NORTH BAY HYDRO

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Tuesday, October 29, 2013

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

Attention: Kristen Walli, Board Secretary

Dear Ms. Walli:

Re: North Bay Hydro Distribution Ltd. (EB-2013-0157)
Application for 2014 Electricity Distribution Rates
Responses – D. Rennick Interrogatories

Please find attached a complete copy of Mr. Rennick's interrogatory responses.

Two hard copies of this submission will be sent via courier. An electronic copy of the response in PDF format will be submitted through the Ontario Energy Board's RESS.

An electronic copy of the response in PDF format will be forwarded via email to the Intervenors as follows:

Donald Rennick
- a) Donald Rennick, Independent Participant

Vulnerable Energy Consumers Coalition
- a) Michael Janigan, Public Interest Advocacy Centre
- b) Shelley Grice, Econalysis Consulting Services

Yours truly,

Original signed by

Melissa Casson, CGA
Regulatory Manager
North Bay Hydro Distribution Limited
(705) 474-8100 (300)
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Manager's Summary – 6) Tax Changes

The "NorthBay_2014_IRM_Tax_Sharing_Model.....XLSM" file contains an error on "Sheet 5 - Z-Factor Tax Changes".

The reference in the formula in Cell C20 should be D29 not D27 which would change the information in that cell to read; "For the 2010 year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #)". That figure, taken from the 2010 COS tax calculation, is $34,000.

Correction of the reference Cell C20 and entry of the $34,000 as a positive amount in Cell I20 will change the Shared Tax Savings amount to a credit of $71,006 which changes the rate rider for some of the volumetric rate classes. (See graphic below)

Please note that this omission was not noticed by anyone in the last three IRM's (EB-2010-0102, EB-2011-0187, and EB-2012-0152) resulting in a $17,000 per year underestimate of the tax saving due to ratepayers.

This change will adjust the Tax Sharing rate rider for a majority of the rate classes. Please adjust Sheet 5 to reflect the above changes or indicate the reasoning for not doing so.

Response:

Since 2011 NBHDL has applied an effective tax rate of 28.72% against regulatory taxable income of $2,313,637; both the effective tax rate and the regulatory taxable income were approved in the 2010 Cost of Service (COS) application (EB-2009-0270) as was the resulting $664,477 in PILS expense that is incorporated into NBHDL's Board-approved base rates. It is this grossed up PILS amount of $644,477 that known tax changes are applied to in order to determine the 50/50 tax savings amount. This method was explained in NBHDL's submission to the Board on January 23, 2012, beginning on page 9 in the 2012 IRM proceeding (EB-2011-0187). For ease of reference, NBHDL has attached the submission as Appendix "A". NBHDL included the 2010 Draft Rate Order (DRO) as Appendix "D" in the 2014 IRM application submitted August 30th, 2013; please see Appendix "G" within the DRO for PILS confirmation. Utilizing the effective tax rate of 28.72% allows NBHDL to incorporate the impact of the tax credits into the calculation and therefore manually entering the tax credits of $34,000 into Cell I20 is not required.

Appendix "J" – Prudence Review of Smart Meter Costs - Application for Recovery of Smart Meter Capital and OM&A Costs

APPLICATION – Page 1 of 21

The application is seeking to recover the balance of $2,207,161 for smart meter costs from 2006 – 2013 and $451,412 for estimated smart meter costs in 2014.

1. After deducting amortization, please indicate the amount included in the figures noted above which does not represent an actual "cost" but represents a calculated figure for such items as deemed interest, return on equity and PIL's. Please note the question does not require that you justify the inclusion of these calculated amounts but requests the figure that represents the total of these amounts.

Response:

NBHDL disagrees with the characterization that there are costs within the application that do not represent an actual "cost". All costs can be found within the Smart Meter Model, tab "5.SM_Rev_Reqt".

2. In this application, Smart meter amortization has been treated differently, from a rate setting point of view, than amortization of other capital assets purchased by NBHDL. Capital asset amortization expense included in rates remains constant between COS applications, except for the effect of the annual adjustment mechanism, until the next COS application.

In this case, NBHDL has charged customers on a retroactive basis for amortization of these capital assets. Please explain why NBHDL has chosen this unique method for dealing with smart meter acquisition costs.

Response:
NBHDL has not chosen a unique method for dealing with smart meter acquisition costs. NBHDL has followed the Ontario Energy Board's Guideline *G-2011-0001 – Smart Meter Funding and Cost Recovery – Final Disposition* which states the Board's policy and practices pertinent to the funding and cost recovery of the smart meter deployment. NBHDL has completed the Board prepared model that assists in documenting costs and calculating the SMDR and SMIRR.

A copy of G-2011-0001 has been attached for reference in Appendix "B".

3. Return on equity for smart meter acquisitions has been treated differently, from a rate setting point of view, than other capital assets purchased by NBHDL. Return on capital (ROC) expense included in rates remains constant between COS applications, except for the effect of the annual adjustment mechanism, until the next COS application.

In this case, NBHDL has charged customers on a retroactive basis for ROC on these capital assets. Please explain why NBHDL has chosen this unique method for dealing with smart meter acquisition costs.

Response:
NBHDL has not chosen a unique method for dealing with smart meter acquisition costs. As explained in Question # 2, NBHDL followed the Ontario Energy Board's Guideline *G-2011-0001 – Smart Meter Funding and Cost Recovery – Final Disposition.*

As well as charging ROC retroactively, NBHDL has used ROC percentages which reflect those in effect as of 2010. If NBHDL is going to change the usual practice and charge ROC on assets purchased in the interval between COS applications then, in order to be consistent, they should use the ROC percentages in effect during those intervening years. This would have the effect of reducing the requested smart meter recovery rates for Residential Customers from $1.28 to $1.16 (2006 – 2013) and from $1.37 to $1.29 (2014) and for General Service <50kW customers from $7.79 to $7.51 (2006 – 2013) and from $3.20 to $3.02 (2014).

Please explain why NBHDL has chosen this unique method for dealing with smart meter ROC calculations and used ROC percentages from 2010 rather than those in effect during the intervening years 2011 - 2013.

Response:
NBHDL has not chosen a unique method for dealing with smart meter ROC calculations. NBHDL's rates for return on capital were approved in the 2010 COS application (EB-2009-0270) and the Board's policy and practice are that the cost of capital parameters from the last approved COS application continue until the next rebasing application. NBHDL is still under the IRM regime and as such the rates approved in 2010 included in the Smart Meter model apply to the intervening years 2011-2013.

Manager's Summary – Item # 10 Web Presentment

States that TOU consumption within 24 hours of availability is critical if customers are to take control of electricity consumption patterns over the longer term and that customers must be provided with the tools to derive the benefit of the provincially mandated smart meter system.

In order to support this ongoing expense:

1. Please give some specific real world examples of why access to consumption within 24 hours of availability is critical and would provide any real benefit to the average residential customer. Please provide these examples with a view to explaining how they would be, in any practical way, superior to the present situation without access to that information.

Response:

Access to electricity information allows homeowners to make more informed decisions about their day-to-day use and expands the capabilities of smart meter two way communication. The web-present solution in question allows customers to readily access their historical electricity consumption to better understand their usage patterns. Homeowners can now understand exactly the times in a day when their electricity consumption is typically high or low and can also compare their seasonal usage. This unique capability allows homeowners to have a higher understanding of their use, thereby encouraging them to conserve energy. More importantly, it allows residents to begin considering energy efficiency upgrade opportunities in their home to reduce costs.

Smart meter data access and presentment is an area that is constantly growing. The Ontario Ministry of Energy is currently encouraging utilities to expand the capabilities of their web-present solutions to include the provinces "Green Button" initiative http://news.ontario.ca/mei/en/2013/10/ontarios-green-button-initiative.html. In the near future, customers will have the ability to share their secured data with a third party vendor who can develop custom applications desired by consumers. For example, an application can parse through two years' worth of historical electricity data in a few seconds and make immediate recommendations to the home owners on what they can do to cut their use. Another example would be an application that can review historical electricity information and size a renewable solar system that the homeowner can acquire to meet their electricity needs.

Currently, none of this capability exists for the customer. The only way for consumers to take part in the market is by following Time-of-Use (TOU) pricing. However, customers are unaware of what they need to do to reduce or shift their energy usage. They are unable to investigate when or why their electricity use was high in any given month. The web-present solution allows customers to become their own investigators or seek help from the local utility.

It is important to note that not every single homeowner will take utilize the web-presentment at this point, however, 20% of NBHDL's customer base is already utilizing the portal on a regular basis after being launched only a few short months ago. A recent customer survey indicated that one the top requests from NBHDL customers was for NBHDL to provide information on how customers can reduce electricity costs; environmental management and energy conservation are becoming extremely important and the average homeowner wants to do their part to conserve. NBHDL is in a position to enable customers to take part and needs to play an integral part in introducing emerging technologies. The industry itself is moving towards integrating social media, benchmarking tools, and applications for end customers and NBHDL needs to be able to offer these capabilities to its customer base.

2. Please give some specific real world examples of how access to consumption within 24 hours of availability would be necessary to assist customers to take control of electricity consumption patterns over the longer term.

Response:

The hourly historical electricity data allows customers to have close oversight on their day-to-day usage. By monitoring their 24 hour historical electricity profile, customers are empowered to take full control of the electrical systems in their home. For example, a customer can be sure that they have been turning their lights off before leaving for work in the morning, or making sure the central AC unit was turned off during hours not required. If items in the household are not being shut off on a regular basis, customers will have the ability to validate this information through the web-present solutions.

Energy conservation does not happen with a press of a button. It is a life style change that needs to be embraced by all parties living in the home. The web-present solution is one step closer to this life style change as it allows customers to monitor their daily usage history and make informed decisions that have long-term benefits.

APPENDIX "A"

NBHDL 2012 IRM – EB-2011-0187

NBHDL REPLY SUBMISSION – JANUARY 23, 2012

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Monday, January 23, 2012

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

Attention: Kristen Walli, Board Secretary

Dear Ms. Walli:

Re: North Bay Hydro Distribution Ltd. (EB-2011-0187)
Application for 2012 Electricity Distribution Rates
Reply Submission to Board Staff, VECC and D.D. Rennick Submissions

Please find attached a copy of North Bay Hydro Distribution Ltd.'s response to Board Staff, VECC and Donald D. Rennick's submissions of comments with regards to the 2012 IRM application.

Two hard copies of this submission will be sent via courier. An electronic copy of the response in PDF format will be submitted through the Ontario Energy Board's RESS.

An electronic copy of the response in PDF format will be forwarded via email to the Intervenors as follows:

Donald Rennick
a) Donald Rennick, Independent Participant

Vulnerable Energy Consumers Coalition
a) Michael Buonaguro, Public Interest Advocacy Centre
b) Shelley Grice, Econalysis Consulting Services Inc.

Yours truly,

Original signed by

Todd Wilcox,
C.O.O
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RESPONSE TO BOARD STAFF, VECC AND D.D. RENNICK SUBMISSIONS
NORTH BAY HYDRO DISTRIBUTION LTD.
EB-2011-0187

North Bay Hydro Distribution Ltd. ("NBHDL") filed an application (the "Application") with the Ontario Energy Board (the "Board"), received on October 14, 2011, under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval for changes to the distribution rates that North Bay charges for electricity distribution, to be effective May 1, 2012. The Application is based on the 2011 3rd Generation Incentive Regulation Mechanism ("IRM").

Based on a review of the evidence submitted by NBHDL, the Board, VECC and Mr. Donald Rennick filed their submissions on January 9, 2012 on the following matters:

- Adjustments to the Revenue-to-Cost Ratios;
- Disposition of Group 1 Deferral and Variance Account Balances;
- Account 1562 – PILs Disposition;
- Account 1521 – Special Purpose Charge ("SPC");
- Shared Tax Savings; and
- Lost Revenue Adjustment Mechanism ("LRAM").

This document reviews the submissions of Board staff, VECC and Mr. Rennick and provides the reply submission of NBHDL on the matters stated above.

BOARD STAFF SUBMISSION REPLY:

Adjustments to the Revenue-to-Cost Ratios

Board staff submits that the proposed revenue-to-cost ratio adjustments are in accordance with the Board's Decision in the EB-2009-0270 proceeding.

NBHDL Reply Submission

NBHDL has no further comments on this issue.

Disposition of Group 1 Deferral and Variance Account Balances

Board staff has reviewed North Bay's Group 1 Deferral and Variance account balances and notes that the principal amounts to be disposed of as of December 31, 2010 reconcile with the amounts reported as part of the RRR. Board staff therefore submits that the amounts should be disposed of on a final basis. Board staff notes that North Bay's application is not consistent with the guidelines outlined in the EDDVAR Report with respect to the default disposition period for Group 1 accounts (i.e. one year). Staff notes that the total bill impact using a one year disposition period is an increase of 2.32% while the total bill impact for two years (as proposed) is an increase of 0.47%. These bill impacts include North Bay's Group1 account balances and accounts 1521 and 1562. While recognizing the value of the EDDVAR Report in guiding decisions with respect to the disposition of deferral and variance account balances, Board staff notes that in the past, the Board has made decisions which deviate from the EDDVAR Report if it deems it in the public interest to do so. In this application, Board staff believes that using a disposition period of 2 years would strike an appropriate balance between reducing intergenerational inequity and mitigating rate volatility. Therefore, Board staff supports North Bay's proposed disposition period of two years.

NBHDL Reply Submission

NBHDL has no further comments on this issue.

Account 1562 – PILs Disposition

2001 Fourth Quarter and 2002 PILS Entitlement

The applicants in the Combined Proceeding had an effective date of rate change including the 2001 and 2002 PILs proxies on March 1, 2002. North Bay requested, and was granted, an effective date of rate change of May 1, 2002 so that, for the 2002 rate year, North Bay was only eligible to recover PILs in rates from May 1, 2002. Board staff submits that since North Bay requested, and the Board granted an effective date of rate change of May 1, 2002, North Bay should not record the 2001 fourth quarter and 2002 PILs proxies or entitlements for the period prior to the effective date of May 1, 2002. Board staff submits that North Bay should file the revised PILs reconciliation worksheet, continuity schedule and EDDVAR continuity schedule. Board staff submits that the proxy recognition in the continuity schedule should be based on the number of months between May 1, 2002 and the next rate change approved by the Board which will result in a lower proxy that reflects the number of months of collection from ratepayers.

NBHDL Reply Submission

NBHDL is unclear on what the Board Staff Submission is actually recommending. It appears that Board Staff is recommending both a reduction in PILs entitlement, from the amount approved in rates, and a change in the timing relating to the entitlement to recover PILs. NBHDL submits that the Board Staff position is not just, not reasonable and is punitive to NBHDL based on the following:

1) *Effective Date of Entitlement*

   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. NBHDL believes that this precedent should apply equally to all LDCs (including NBHDL). The three combined proceeding applicants (EnWin, Halton Hills and Barrie) started recording entitlements on October 1, 2001 (for 2001 PILS) and January 1, 2002 (for 2002 PILS). NBHDL could not locate the 2002 rate decisions approving 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.

It is NBHDL's understanding that the OEB is continuing this principle and is approving entitlements commencing with taxation, not effective date of rate approvals, for PILs applications subsequent to the combined proceeding.

2) *Lower Level of PILS Approved in North Bay Hydro Rates Compared to Regulatory Entitlement*

NBHDL reduced the 2002 PILs recovery in rates from rate payers by 62% (reduction of $780,095) as an effort to mitigate customer impacts. The 2002 PILs approved in rates ($478,122) was 38% of the value calculated using the PILs determination model ($1,258,217). The Board Staff position would further reduce NBHDL's 2002 PILs revenue below the level approved in rates, which has already been lowered to the benefit of ratepayers. NBHDL is of the opinion that it has been more than fair to its rate payers and does not agree that PILs revenue should be further reduced.

The Board Staff submission to alter the entitlement horizon and/or amount for 2001 PILS would further penalize NBHDL through reduced PILs entitlement recovery.

3) *Delay in Approval of Distribution Rates*

NBHDL believes that the Board Staff position disadvantages NBHDL relative to the parameters of approval for other LDCs. As an example, LDCs with rates approved March 1, 2002 are allowed entitlement commencing October 1, 2001. It is unfair to effect a 7 month delay in entitlement (October 2001 to May 2002) for a 2 month (March 2002 to May 2002) delay in rate approval.

4) *North Bay Expectations at Time of Rate Approval (May 1, 2002)*

Excerpt from Board Staff Submission

Ref: Page 2 of the Amended Manager's Summary for North Bay's 2002 Rate Application

> "The increase of distribution revenue as a result of this rate submission is $1,247,835. This excludes about $690,000 in account 1570 for transition costs

and a reduction of $740,854 in 2002 proxy taxes. We plan to recover the associated loss of revenue through efficiency improvements for both these amounts. If need be we will submit for Transition costs and proxy taxes during the next annual filing."

This statement assumed NBHDL would receive full recovery of the approved PILs included in rates. The reference to efficiency gains were to off-set the reduction in full entitlement revenue (2002 PILS reduction and transitions costs). NBHDL did not contemplate having to off-set a further reduction in Distribution Revenue relating to PILs revenue approved in rates, which Board Staff are indicating.

5) *Regulatory Principles of PILs*

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, NBHDL 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).

For the reasons outlined above, NBHDL believes that the continuity schedule as originally filed is just and reasonable and follows the rules as outlined in the combined proceeding. This results in full recovery of PILs approved in rates and an entitlement commencing with taxation not the effective date of rate approvals.

Write-down of Capital Property and Loss of Disposal of Assets

Under the PILs methodology, Board staff submits that fixed asset transactions should not true-up to ratepayers and thus appear on the TAXREC3 sheet of the SIMPIL model. Utilities receive a return on fixed assets included in rate base and, if an asset is written down or disposed, the utility continues to receive a return until its next rate rebasing application. Board staff submits that the write-down of capital property of $540,755 in 2002 and the loss on disposal of assets of $144,597 in 2004 should not true-up to ratepayers. Board staff submits that North Bay should move the transactions to TAXREC3 in the 2002 and 2004 SIMPIL models respectively and that North Bay should re-file the corrected 2002 and 2004 SIMPIL models, PILs continuity schedule and EDDVAR continuity schedule.

NBHDL Reply Submission

NBHDL respectfully disagrees with the Board Staff position above and refers the Board panel to the full body of evidence submitted in response to Board Staff Interrogatories (IR# 7 & 8). NBHDL believes that these two adjustments to taxable income should be part of the SIMPILS methodology process that trues-up to rate payers.

NBHDL has reviewed the SIMPILS models approved as part of the combined proceeding and does not believe a precedent has been established by the OEB regarding the true-up of gains/losses/write-downs on disposal of assets. The combined proceeding applicants had differing treatments of both gains and losses on disposal of assets, contained in the final version of the SIMPILS models. Some of the combined proceeding applicants categorized these items on TaxRec3, resulting in no true-up, while other applicants categorized these items on TaxRec2, but in all instances the amounts were less than materiality, again resulting in no true-ups. Regardless of the categorization (TaxRec2 or TaxRec3) these adjustments would not have been trued-up due to the fact that they are all less than materiality.

NBHDL believes that the write-down and loss on disposal should be trued-up to ratepayers based on the arguments recited below and the fact that these amounts meet the materiality test as part of the SIMPILS true-up process. NBHDL has laid out all pertinent arguments for our proposed treatment in the Board Staff Interrogatory responses which are provided below for reference:

> ***7. Reference: Appendices 13 and 15, 2002 and 2004 SIMPIL models Appendix 20, 2002 T2 Federal Tax Return and 2002 Audited Financial Statements, Write-down of Capital Property and Loss of Disposal of Assets***
>
> *The 2002 T2 Schedule 1 shows an addition for a write-down of capital property of $540,755 that is not deductible for tax purposes.*
>
> *a) What was the business reason for writing down this asset?*
>
> > ***Response:***
> > *The asset (building) was written down to fair market value.*

b) *Was the asset sold to a municipal owner, an affiliated company, or an associated company?*

Response:
The asset was sold in 2004 to a 3rd party.

c) *Did North Bay apply to the Board for the recovery of the write down?*

Response:
No, NBHDL is unaware of any application for recovery of the write down.

d) *This addition was added to the 2002 SIMPIL model TAXREC2 sheet row 34 cell C34. Material items recorded on TAXREC2 true-up to the ratepayers only. However, if the value of the asset was included in rate base in 2001, shareholders are getting a continued benefit in distribution rates. A write down of assets is accelerated depreciation and does not true up in the PILs methodology.*

Please explain why this asset write-down should true up to ratepayers and not to the shareholder.

Response:
The write-down relates to the movement to fair market value of an asset that was, at the time, used by NBHDL to provide distribution services to its customers. Costs related to provision of distribution services are allowed to be recovered in rates.

While NBHDL did not apply for specific recovery of the write-down it continued to receive payments from customers to partially mitigate the loss of economic value. NBHDL continued to receive, in the 2002 to 2006 period, depreciation and market based rate of return related to the write-down amount. This stopped in 2006 when LDCs were permitted to rebase for distribution rates May 1, 2006 based on based on December 31, 2004 values (which reflected the write-down).

In addition, NBHDL through its treatment of the write-down as a TAXREC2 item resulting in true up from its customers is filing for *recovery of the tax impact only related to the write-down. On a net basis the shareholder still absorbed a portion of the write-down.*

NBHDL considers this treatment fair as the asset was required for service and did not exist exclusively for the benefit of the shareholder.

e) If North Bay agrees it benefits shareholders only, please move the transactions to TAXREC3.

Response:
As stated in 7 d) above, NBHDL considers the treatment of this item in TAXREC2 as fair as the asset was required for service and did not exist exclusively for the benefit of the shareholder.

8. The 2004 T2 Schedule 1 shows an addition for a loss on disposal of assets of $144,597.

a) Is this the same asset that was written down in 2002?

Response:
Yes, this is the same asset that was written down in 2002.

b) This addition was added to the 2004 SIMPIL model TAXREC2 sheet row 19 cell C19. Material items recorded on TAXREC2 true-up to the ratepayers only.

Please explain why a loss on disposal of assets on which shareholders are getting a return in distribution rates and a CCA tax benefit should true-up to ratepayers and not to the shareholder.

Response:
NBHDL believes its treatment as a TAXREC2 item with true-up from its customers is fair for the same reasons articulated in response to question 7 d).

NBHDL sold the facility in 2004 as part of an effort to rationalize facilities and ultimately reduce costs for customers. NBHDL did not apply for *specific recovery of the loss on sale. Again, NBHDL continued to receive payments from customers to partially mitigate the loss on sale. NBHDL continued to receive, in the 2004 to 2006 period, depreciation and market based rate of return related to the loss on disposal amount. This stopped in 2006 when LDCs were permitted to rebase for distribution rates May 1, 2006 based on based on December 31, 2004 values (reflected the sale).*

NBHDL through its treatment of the loss on disposal as a TAXREC2 item resulting in true up from its customers is filing for recovery of the tax impact only related to the loss. On a net basis the shareholder still absorbed a portion of the loss on disposal (a larger portion than the write-down to FMV).

NBHDL considers this treatment to be fair as the loss on sale led to future reduced costs for customers and the asset did not exist exclusively for the benefit of the shareholder.

c) *If North Bay agrees it benefits shareholders only, please move the transactions to TAXREC3.*

Response:
As stated in 8 b) above, NBHDL considers the treatment of this item in TAXREC2 as fair as the loss on sale led to future reduced costs for customers and the asset did not exist exclusively for the benefit of the shareholder.

Account 1521 – Special Purpose Charge (“SPC”)

Board staff submits that despite the usual practice, the Board should authorize the disposition of Account 1521 as of December 31, 2010, plus the amount recovered from customers in 2011, including carrying charges as of April 30, 2012, because the account balance does not require a prudence review, and electricity distributors are required by regulation to apply for disposition of this account by April 30, 2012 in any event. It is Board staff’s view that that there is no need to await the outcome of final audited results when these results may be available after April 30, 2012. Consistent with the treatment of Group 1 account balances and account 1562, Board staff submits that a disposition period of two year should also be used.

NBHDL Reply Submission

NBHDL has no further comments on this issue.

Shared Tax Savings

Board staff notes that there are discrepancies between the regulatory taxable income used by North Bay in the 2012 Shared Tax Savings Workform and the regulatory taxable income included in the 2010 Revenue Requirement Work Form ($2,313,638 versus $1,649,160). This change would increase the amount to be returned to ratepayers from $15,638 to $102,200. Board staff invites North Bay to comment on this adjustment in its reply submission and indicate, given the magnitude of the refund, whether it still proposes to record this amount in account 1595 for future disposition.

NBHDL Reply Submission

Based on discussions with Board staff, it was NBHDL's understanding that the regulatory taxable income to be utilized in the 2012 Shared Tax Savings Workform should be the same figure used in the 2011 Shared Tax Savings Workform; the model would then calculate the appropriate tax sharing amount. There was discussion on the use of a regulatory taxable income that incorporated the gross up factor; however, NBHDL was advised that the model worked appropriately and followed Board policy. NBHDL acknowledges that there is a discrepancy between the regulatory taxable income used in the model and the 2010 Revenue Requirement Workform, however, this issue was thought to be fully resolved during the 2011 IRM process. In its 2010 COS application, NBHDL was approved for $686,307 for income and capital taxes[1]; this was based on an effective tax rate of 28.72%. By utilizing the regulatory taxable income of $2,313,638 and an effective tax rate of 28.72%, the model calculates the approved PILS amount. It is NBHDL's assumption that the 2012 IRM3 Shared Tax Savings Work form model should calculate an identical grossed up tax amount as was approved in the 2010 COS decision.

After reviewing Board Staff comments with regards to this model, NBHDL acknowledges the confusion surrounding this particular issue, especially with the unique revisions made to NBHDL's model in 2011 and the complexity of the PILs. Upon further review NBHDL feels that the model as currently calculating does not take into account that the regulatory taxable income used for the 2012 tax saving calculation already incorporates both the approved tax credits and the gross up factor. In the 2011 IRM decision, NBHDL and Board Staff agreed on the appropriateness of a revised Shared Tax Savings Workform to accommodate this calculation method and a tax savings of $16,285 was recorded in variance account 1595[2].

[1] Page 5 of the Draft Rate Order and pages 29 and 54 of the Settlement Agreement – EB-2009-0270
[2] Page 4 of Board Staff Submission – EB-2010-0102 and Page 4 of Decision and Order

NBHDL has prepared a revised Shared Tax Savings calculation using the principals approved in the 2011 decision – please see Appendix "A". The variance between the 2011 IRM Shared Tax Savings estimate of 2012 tax savings and the proposed 2012 IRM Shared Tax Savings is reflective of the decrease in estimated 2012 tax rates. NBHDL respectfully submits that a consistent regulatory taxable income which would incorporate the effective tax rate and therefore eliminate the need to adjust income for both the tax credit and the gross up factor should be utilized in the 2012 Shared Tax Savings Workform. NBHDL submits that the method used to calculate the 2011 IRM shared tax savings should be applied in the 2012 IRM proceeding as it was deemed appropriate in the Board's Decision in EB-2010-0102. Utilizing the same method as approved in the 2011 IRM decision results in total tax amount would be $573,557. Incremental tax savings would be $112,570 and NBHDL submits that 50% of this amount, $56,285, should be recorded in Account 1595. This treatment would be consistent with the 2011 IRM decision and incorporates the impact of tax credits and the gross up factor into the regulatory taxable income which the shared tax savings amount is based on.

LRAM Claim

2010 programs and persisting impacts of 2008-2010 programs

In cases in which it was clear in the application or settlement agreement that an adjustment for CDM was not being incorporated into the load forecast specifically because of an expectation that an LRAM application would address the issue, and if this approach was accepted by the Board, then Board staff would agree that an LRAM application is appropriate. North Bay may want to highlight in its reply whether the issue of an LRAM application was addressed in their cost of service application. In the absence of the above information, Board staff therefore does not support the recovery of the requested persisting lost revenues from 2008 and 2009 CDM programs in 2010, the lost revenues from 2010 CDM programs, or the lost revenues from 2008-2010 CDM programs persisting from January 1, 2011 to April 30, 2012 as these amounts should have been built into North Bay's last approved load forecast.

NBHDL Reply Submission

With a provincial directive to encourage conservation, NBHDL aggressively promoted OPA programs throughout its service territory without hesitation. NBHDL has been a leader in terms of penetrating conservation markets and targets and has voluntarily gone above and beyond in its interactions with customers and the programs it has instituted. NBHDL proactively and voluntarily included estimates of 2009 and 2010 CDM program savings into its 2010 load forecast and it is unreasonable that Board staff would suggest that the savings in excess of that forecast should not be included in its LRAM claim; NBHDL should not be penalized for following provincial directive by promoting conservation and attaining higher than expected results. LRAM is in place to remove the disincentive to deliver CDM programs which erode distribution revenue, to deny this true-up would send a message that LDCs not go above and beyond to achieve forecasted CDM savings targets. This message does not align with the intent of LRAM claims and this very issue is addressed in the recently released CDM guidelines[3]. NBHDL is unclear why the principals outlined in the new CDM guidelines would not be applied to NBHDL's application, especially in light of NBHDL's proactive stance towards conservation.

The Board staff's submission on NBHDL's LRAM claim offers its view that LRAM claims pertaining to a test year and beyond would be unnecessary once a distributor rebases and accordingly updates its load forecast. However, Board staff states in its submission that:

> "In cases in which it was clear in the application or settlement agreement that an adjustment for CDM was not being incorporated into the load forecast specifically because of an expectation that an LRAM application would address the issue, and if this approach was accepted by the Board, then Board staff would agree that an LRAM application is appropriate. North Bay may want to highlight in its reply whether the issue of an LRAM application was addressed in their cost of service application."

An LRAM application for 2008 and 2009 programs beyond 2010 was addressed in NBHDL's 2010 COS application:[4]

> "The lost revenue associated with the OPA programs delivered and/or supported by NBHDL will not be recovered for 2008 and beyond in the 2010 application as the OPA program results are not finalized at this time. Once the final results are known NBHDL will file for recovery of LRAM in future applications."

As indicated by the Board staff quote, Board staff would support NBHDL's LRAM as claimed since NBHDL had reported in their 2010 COS application that its intent was to file LRAM for programs launched in 2008 and beyond at a later date. That NBHDL included estimates of 2009 and 2010 CDM program savings into its 2010 load forecast should be viewed proactively as this reduced the size of the associated LRAM claims for 2010 and beyond.

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[3] See EB-2012-0003 – Guidelines for Electricity Distributor Conservation and Demand Management – page 10
[4] See EB-2009-0270 Exhibit 10 page 3

Board staff also quotes the following from the CDM Guidelines:

> “Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.”

NBHDL understands that lost revenues associated with historic programs are to be incorporated into the load forecast and not to be claimed again. However, it is inappropriate that energy savings for programs that were not available at the time, did not enter the load forecast and thus did not impact these new rates should be denied an LRAM. This is particularly true since NBHDL expressly stated in its COS that an LRAM would be filed on these energy savings at a later date. The load forecast model used by NBHDL was accepted by the Board in NBHDL’s 2010 Cost of Service (COS) proceeding, EB-2009-0270, and as explained in the reply submission to VECC, 2008 OPA programs savings had minimal if any impact on the 2010 predicted purchases used to determine 2010 distribution rates. NBHDL respectfully refers the Board to its submission reply below for VECC for further information on the CDM savings incorporated into its 2012 IRM claim and the justification for NBHDL’s submission that the proposed LRAM claim of $97,210 is appropriate and reasonable. NBHDL submits that the LRAM claim put forward by NBHDL is accounting for the difference between the forecasted revenue loss embedded in rates and the actual revenue loss incurred by the utility and it is reasonable, just and appropriate.

2008 and 2009 programs

Board staff notes that North Bay has not collected 2008 lost revenues from OPA CDM programs and the lost revenues associated with both 2009 third tranche CDM programs and 2009 OPA CDM programs, years during which North Bay was under IRM. Board staff supports the approval of the 2008 and 2009 lost revenues requested by North Bay as these lost revenues took place during IRM years and North Bay did not have an opportunity to recover these amounts. Board staff notes that this is consistent with what the Board noted in its decisions on applications from Horizon (EB-2011-0172), Hydro One Brampton (EB-2011-0174), and Whitby Hydro (EB-2011-0206). Board staff requests that North Bay provide an updated LRAM amount that only includes lost revenues from 2008 and 2009 CDM programs in the years 2008 and 2009 and the subsequent rate riders.

NBHDL Reply Submission

Board staff had requested that NBHDL submit as part of its reply submission lost revenue amounts for 2008 and 2009 programs for 2008 and 2009 as NBHDL was under IRM during that time. NBHDL respectfully notes that it was also under IRM for the first four months of 2010.

Table 1 below provides the breakdown of the requested lost revenue from which the lost revenue during the IRM period can be obtained. Lost revenue during the IRM period was $53,135. However, NBHDL still requests that the Board approve the LRAM claim for $ $97,210 as supported by Board staff and all other evidence.

Table 1 - LRAM claim during and after the IRM period

	IRM	**IRM**	**IRM**	**2010 Load forecast**	**2010 Load forecast**	**2010 Load forecast**	Total
	2008	2009	Jan 1 to Apr 30 2010	May 1 to Dec 31 2010	2011	Jan 1 to Apr 30 2012	
Residential	$12,061	$18,861	$8,704	$8,933	$18,250	$8,302	$75,111
GS < 50 kW	$0	$0	$0	$0	$0	$0	$0
GS > 50 kW	$417	$7,411	$3,733	$463	$3,970	$3,532	$19,526
LRAM total	$12,478	$26,272	$12,437	$9,396	$22,220	$11,834	$94,637
Carrying charges	$773	$861	$315	$253	$313	$58	$2,572
Total claim	$13,250	$27,133	$12,752	$9,649	$22,533	$11,892	**$97,210**
Cumulative LRAM	$13,250	$40,383	$53,135	$62,784	$85,318	**$97,210**	

VECC SUBMISSION REPLY:

Revenue-to-Cost Ratios

VECC submits that the adjustments to revenue-to-cost ratios are in accordance with the Board's EB-2009-0270 decision and that the Revenue-Cost Ratio Adjustment Work Form has been completed appropriately.

NBHDL Reply Submission

NBHDL has no further comments on this issue.

Lost Revenue Adjustment Mechanism (LRAM Recovery)

OPA Funded Programs

VECC submits that NBHDL has appropriately demonstrated through interrogatory responses that the current LRAM claim accounts for any measures that have expired before the full span of the LRAM claim.

NBHDL Reply Submission

NBHDL has no further comments on this issue.

Load Forecast

VECC notes that Table 1 in IndEco's updated LRAM Report shows different values for reductions to the energy savings eligible for an LRAM claim compared to the values provided above in 3.14 as per the response to VECC interrogatory # 2 (b).

NBHDL Reply Submission

NBHDL has verified with IndEco Strategy Consulting Inc. that Table 1 in their 3rd party report should reflect the same values as those referenced in VECC # 2 (b). The values provided in the updated IndEco report were inadvertently from a draft version.

Load Forecast / 2008 Programs

NBHDL's load forecast incorporated 11 years (1998 to 2008) of historical data. VECC submits that the load forecast methodology utilized by NBHDL in its 2010 COS Application for rates effective May 1, 2010 used a regression analysis of historical data that included actual use and therefore included 2008 CDM program impacts. Any conservation effects up to the end of 2008 would be captured in the historical consumption data. Based on these considerations, VECC submits that lost revenues from NBHDL's 2008 CDM programs are eligible for recovery in 2008 and 2009 but are not accruable in 2010 and beyond as the energy savings are assumed to be incorporated in the 2010 load forecast.

NBHDL Reply Submission

The regression model used in NBHDL's load forecast included the years 1999 through 2008 to arrive at the formula for predicting purchases. The prediction formula utilizes 1999 data as much as it does 2008; for example, 1999 actual data influences the regression analysis and the resulting prediction formula in equal proportion to 2008. As a result, the reduction in CDM savings in 2008 has a minimal impact on the prediction formula used to forecast 2010 purchase values. Further to that point, 2008 actual data would not include the full impact of CDM programs implemented throughout that year. NBHDL would also point to EB-2009-0270, Table 3-8 of Exhibit 3 (page 17 of 29) which highlights the variance between predicted and actual purchases for 2008. This table shows that for 2008, the model is actually predicting 1.2 GWh higher than actual data which suggests that the prediction formula may not be taking the 2008 CDM results into consideration at all. Since the prediction formula is used to forecast 2010 values it is most likely not reflecting any or a very little amount of the 2008 CDM savings. With the exception of minor change in the modification of arithmetic mean from geometric mean, NBHDL's load forecast was accepted by the Board in its 2010 COS[5].

[5] Page 6 of 8 in NBHDL's Draft Rate Order – EB-2009-0270

NBHDL respectfully submits that the 2008 energy savings that are assumed to be incorporated into the 2010 load forecast are immaterial and that it is appropriate for NBHDL to include these 2008 program savings into 2010 and beyond.

2009 and 2010 CDM Programs

VECC submits that the LRAM claim in this application should not include any lost revenue in 2010 from 2010 OPA CDM programs, persisting lost revenues from 2008 and 2009 CDM programs in 2010 and persisting lost revenues from 2008 to 2010 CDM programs over the period January 1, 2011 to April 30, 2012, as the rebasing year forecast is final and these savings should have been incorporated in the 2010 load forecast. VECC submits that lost revenues from 2009 CDM programs in 2009 are eligible for recovery as these savings occurred prior to rebasing. In summary, VECC submits that the LRAM claim should be revised to include only energy savings from 2008 and 2009 CDM programs in 2008 and 2009.

NBHDL Reply Submission

The objective of LRAM is to keep the LDC revenue neutral and to ensure that there is not a disincentive to the LDC in delivering energy savings to customers through CDM programs. NBHDL agrees that once savings are incorporated into the load forecast, there will not be lost revenues associated with those savings. However, the full extent of savings from 2008, 2009 and 2010 programs were not included into NBHDL's load forecast since final results were not available at the time. It is not reasonable to suggest that lost revenues from these programs should not be recoverable when final results from these programs were not available at the time of the load forecast and were not fully incorporated into the forecast as explained above. As submitted in the reply submission above for Board Staff, NBHDL addressed the issue of a future LRAM application for those CDM savings not included in its 2010 load forecast, specifically for 2008 and beyond, in its 2010 COS.[6]

In response to VECC interrogatories, NBHDL decreased its LRAM claim by $90,377 to avoid double counting the savings that had previously been included in the load forecast and that were included in the 2012 LRAM claim in error. NBHDL is entitled to an LRAM claim considered by VECC as a true-up related to the portion of energy savings related to 2009 and 2010 programs in the test year and beyond and it was NBHDL's understanding of the LRAM rules when incorporating a portion of 2009 and 2010 savings into its load forecast that an LRAM claim would be possible for any savings not included in the load forecast and not included in rate setting. While decisions from Hydro One Brampton and Hydro Ottawa quoted by VECC side on denying true-up LRAM claims for unforecasted savings, NBHDL remains firm that these decisions are

[6] See EB-2009-0270 Exhibit 10 page 3

decidedly unfair to LDCs since they deny them the ability to remain revenue neutral with respect to CDM, and prevent the LRAM mechanism from having its intended effect.

NBHDL respectfully submits that CDM savings were considered in the 2010 load forecast and that this has been appropriately reflected in the reduced LRAM claim of $97,210 for 2008, 2009 and 2010 OPA program savings.

D.D. RENNICK SUBMISSION REPLY:

NBHDL respectfully acknowledges Mr. Rennick's submission and has no further comments.

All of which is respectively submitted on this 23rd day of January, 2012.

APPENDIX “A”

PROPOSED 2012 SHARED TAX SAVINGS CALCULATION

Summary - Sharing of Tax Change Forecast Amounts

For the year, enter any Tax Credits from the Cost of Service Tax Calculation (Positive #) $ -

1. Tax Related Amounts Forecast from Capital Tax Rate Changes	**2010**	**2012**	**2011 IRM Estimated 2012**	**Variance**
Taxable Capital	$ 44,105,306	$ 44,105,306	$ 44,105,306	
Deduction from taxable capital up to $15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000	
Net Taxable Capital	$ 29,105,306	$ 29,105,306	$ 29,105,306	
Rate	0.150%	0.000%	0.000%	
Ontario Capital Tax (Deductible, not grossed-up)	**$ 21,650**	**$ -**	**$ -**	
2. Tax Related Amounts Forecast from Income Tax Rate Changes	**2010**	**2012**	**2012**	
Regulatory Taxable Income	$ 2,313,638	$ 2,313,638	$ 2,313,638	$ 2,313,638
Corporate Tax Rate	28.72%	24.79%	26.25%	1.46%
Tax Impact	$ 664,477	$ 573,557	$ 607,307	$ 33,750
Grossed-up Tax Amount	**$ 664,477**	**$ 573,557**	**$ 607,307**	**$ 33,750**
Tax Related Amounts Forecast from Capital Tax Rate Changes	$ 21,650	$ -	$ -	$ -
Tax Related Amounts Forecast from Income Tax Rate Changes	$ 664,477	$ 573,557	$ 607,307	$ 33,750
Total Tax Related Amounts	**$ 686,126**	**$ 573,557**	**$ 607,307**	**$ 33,750**
Incremental Tax Savings		**-$ 112,570**	**-$ 78,820**	**-$ 33,750**
Sharing of Tax Savings (50%)		**-$ 56,285**	**-$ 39,410**	**-$ 16,875**
				-$ 56,285

APPENDIX “B”

ONTARIO ENERGY BOARD GUIDELINE

G-2011-0001 – SMART METER FUNDING AND COST RECOVERY –

FINAL DISPOSITION

Ontario Energy Board

Ontario

G-2011-0001

Guideline

Smart Meter Funding and Cost Recovery – Final Disposition

December 15, 2011

Table of Contents

1. Purpose

This guideline sets out the Board's filing instructions in relation to the funding of and the recovery of costs associated with smart meter activities conducted by Ontario electricity distributors. It reflects amendments to a number of smart metering regulations that were enacted on June 25, 2008 as well as the direction provided by the Board in its combined proceeding on smart meter costs (proceeding EB-2007-0063) and in the previous *Guideline G-2008-0002: Smart Meter Funding and Cost Recovery*. It also includes a synthesis of the Board's policy and practices that have emerged from decisions of the Board from 2007 to present pertaining to the funding and cost recovery related to smart meter deployment.

This guideline supersedes *Guideline G-2008-0002: Smart Meter Funding and Cost Recovery*, issued October 22, 2008.

This updated guideline is intended to provide the Board's general policy and practice, and the underlying principles and rationale with respect to smart meter funding and cost recovery as smart meter deployment is approaching completion for the vast majority of Ontario electricity distributors. While providing guidance to distributors on how to apply for smart meter cost recovery beginning with the 2012 rate year, this document is a guideline and is therefore not determinative of how the Board may decide in any case. The onus is on an applicant to make and support its application in light of its own specific circumstances.

2. Background

2.1 Regulations Enacted June 25, 2008

On June 25, 2008, the Government of Ontario enacted regulations under the *Electricity Act, 1998* (O. Reg. 233/08 and O. Reg. 235/08) and the *Ontario Energy Board Act, 1998* (O. Reg. 234/08) with respect to smart meter activities. These regulations amended pre-existing regulations pertaining to smart metering. With these amended regulations, most Ontario electricity distributors have become authorized for smart meter activities, and have been active in the procurement and deployment of smart meters. Further, completion of smart meter deployment is necessary for the implementation of Time-of-Use ("TOU") rates.

The following table provides a summary of the main regulations pertaining to smart meters.

Table 1: Smart Meter Regulations[1]

Regulation	Description
O.Reg. 393/07	"SMART METERING ENTITY". Defines the IESO as the Smart Metering Entity and defines the activities that are the exclusive responsibility of the SME.
O.Reg. 425/06	"CRITERIA AND REQUIREMENTS FOR METERS AND METERING EQUIPMENT, SYSTEMS AND TECHNOLOGY". With the attachment "Functional Specification for Advanced Metering Infrastructure – Version 2" dated July 5, 2007, provides the technical specifications that smart meters for residential and small general service customers must meet.
O.Reg. 426/06	"SMART METERS: COST RECOVERY". This regulation gives direction to utilities and the Board with respect to eligibility of costs for recovery. This deals with: a) costs that meet minimum functionality per O. Reg. 425/06; b) costs beyond minimum functionality are recoverable only if approved by the Board; c) costs for MDM/R functions that are the responsibility of the Smart Metering Entity are not recoverable, except for priority installations or for supporting the IESO with testing/finalizing the MDM/R requirements and interfacing with the Smart Metering Entity, while MDM/R costs that are the distributor's responsibility are recoverable subject to prudence; and d) distributors will not be financially disadvantaged with respect to the costs for replaced conventional

[1] This table provides a summary of the applicable regulations. Readers should refer to the actual regulations, available at http://www.e-laws.gov.on.ca/index.html, for completeness.

	meters owned before, on or after January 1, 2006 if replaced by a smart meter and not in contravention of section 53.18 of the *Electricity Act*.
O.Reg. 427/06	"SMART METERS: DISCRETIONARY METERING ACTIVITY AND PROCUREMENT PRINCIPLES". This is the main regulation specifying how a utility becomes authorized to procure and deploy smart meters. There are primarily two approaches. First, seven named distributors involved in priority installations (Hydro One Networks, Inc., Enersource Corporation, Powerstream Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Toronto Hydro-Electric System Limited and Veridian Connections Inc.) were authorized; distributors (primarily affiliated distributors) who had smart meters procured under the processes authorized for these named distributors were also authorized. O.Reg. 428/06 also added a number of other named distributors as authorized for priority installations. For other distributors, authorization for smart meter activities if smart meter procurement is pursuant to and in compliance with the parameters and process established by the *Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smartmeter Deployment* dated August 14, 2007.
O.Reg. 428/06	"PRIORITY INSTALLATIONS". The regulation named five additional distributors (Chatham-Kent Hydro Inc., Middlesex Power Distribution Corporation, Milton Hydro Distribution Inc., Newmarket Hydro Ltd., and Tay Hydro Electric Distribution Company Inc.) as authorized for smart meter activities under O.Reg. 427/06 as priority installations. Newmarket Hydro and Tay Hydro have since amalgamated as Newmarket-Tay Hydro.

2.2 The EB-2007-0063 Combined Proceeding on Smart Meters

In mid-2007, the Board conducted a combined proceeding in relation to smart meter costs (the "Combined Proceeding", under Board File No. EB-2007-0063) for the 13 distributors that were at that time authorized by regulation to conduct smart meter activities. In its Decision with Reasons, issued on August 8, 2007, the Board addressed the following issues:

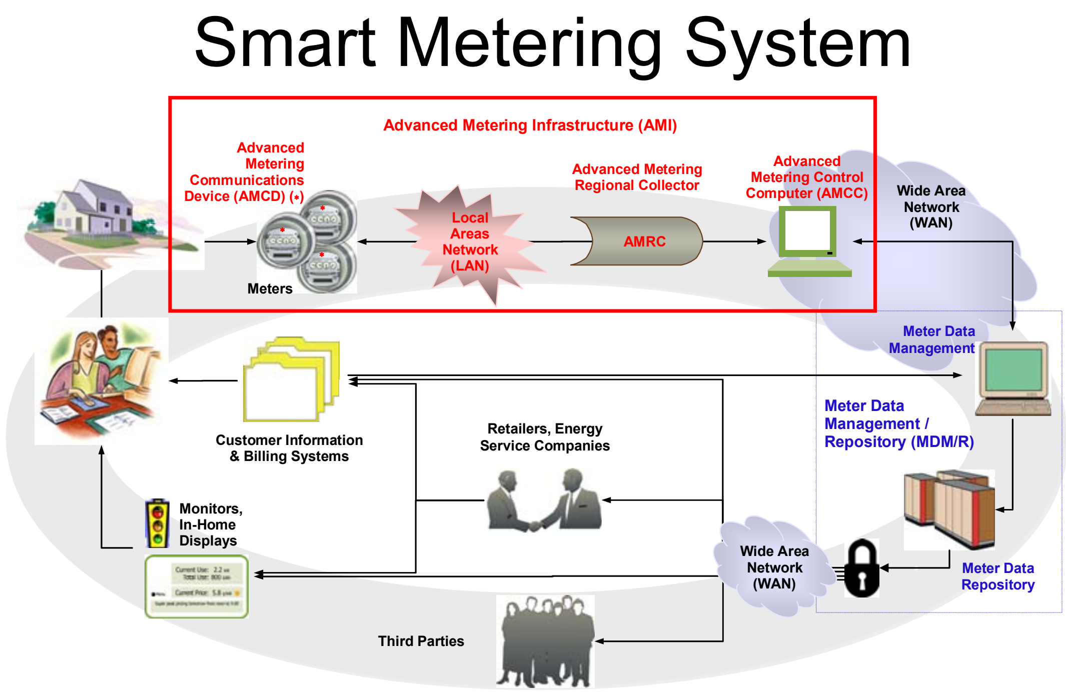
- the interpretation of minimum functionality;
- the smart meter procurement process;
- smart meter costs;
- dealing with stranded meter costs;
- accounting procedures related to smart meter costs; and
- the methodology for recovery of smart meter costs through rates.

These are discussed in further detail below.

Minimum Functionality

The minimum functionality for advanced metering infrastructure for residential and small general service customers is set out in O. Reg. 425/06, *Criteria and Requirements for Meters and Metering Equipment, Systems and Technology* and the associated document *Functional Specification for an Advanced Metering Infrastructure, Version 2*, issued July 5, 2007 (the “Functional Specification”).

In the Combined Proceeding, the Board defined minimum functionality as shown in the “Advanced Metering Infrastructure (AMI)” area in the diagram below. It includes an advanced metering communication device, a local area network, an advanced regional collector, and an advanced metering central computer.



Procurement Process

In terms of the procurement process, the Board noted that its assessment of prudence relates to both the price paid for goods and services and the procurement process itself. In its review during the Combined Proceeding, the Board noted that the procurement process with respect to the original 13 distributors authorized to undertake smart metering activities was unique, and that the Government had been extensively involved. The Board was satisfied that, at a high level, the evidence demonstrated that the distributors acted in a professional manner, exercised the necessary due diligence and maximized buying economies through buying groups.

With the amended regulations enacted in the summer of 2008, most distributors have subsequently become authorized to procure and deploy smart meters under O.Reg. 427/08 and pursuant to the London Hydro RFP process. Under the London Hydro RFP process, there was a selection process to match each participating distributor, or group of distributors, to vendors from a group pre-selected through the London Hydro RFP process. Based on the characteristics and requirements of the distributor(s) and the vendors, pre-selected vendors were ranked from one to three for a particular distributor or distributor group. It was then up to the distributor to enter into a contractual agreement with one of these three vendors, starting with the highest ranked, to determine pricing arrangements, technical specifications and schedules for delivery and installation. The selection process was overseen by a Fairness Commissioner. Any deviations from this process required approval from the Ministry.

Smart Meter Costs

In its decision to the Combined Proceeding, the Board identified the categories of capital and operation, maintenance and administration costs that relate to smart meter minimum functionality.

The Board accepted that different situations can affect the costs. Installation costs in rural areas may be more expensive than in urban areas. Installation costs may also be more expensive in areas characterized by older construction as opposed to newer construction. Other factors that can also affect costs include the number of meters installed and the degree to which costs are incurred up front.

Treatment of costs associated with the repair and replacement of customer-owned equipment were also considered in the proceeding. The Board determined that all labour and associated costs incurred, with the exception of material and parts costs for customer-owned equipment, should be capitalized and tracked in a sub-account of the Smart Meter Capital and Recovery Offset Variance Account 1555. The actual costs for materials and parts to repair or replace any customer-owned equipment should be expensed and also tracked separately in a different sub-account of the Smart Meter OM&A Variance Account 1556 until disposition is ordered by the Board following a review for prudence of the smart meter costs. As the meter base remains the property of the customer, the Board determined that it would not be appropriate to have it form part of the distributor's rate base.

Stranded Costs, Accounting Procedures and Methodology for Cost Recovery in Rates

Although the decision in the Combined Proceeding provided some direction in relation to stranded meters, accounting procedures and cost recovery through rates, the Board's view on these matters has evolved over time as reflected in more recent accounting documents and rate decisions, and the revisions to O.Reg. 426/06. Distributors should therefore be guided by the sections later in this guideline with respect to these matters.

2.3 2011 Smart Meter Applications and Board Decisions

Subsequent to the Combined Proceeding, the Board has considered smart meter funding and cost recovery through individual applications.

The following summarizes key findings from decisions that were issued by the Board during the course of the 2011 electricity distribution rate ("EDR") process.

(i) Smart Meter Funding Adder

In many 2011 EDR rate applications, whether incentive regulation mechanism ("IRM") or cost of service, the Board determined that the existing or proposed Smart Meter Funding Adder ("SMFA") would cease on April 30, 2012. The Board noted that the SMFA is a tool designed to provide advance funding for smart meter procurement and deployment, and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board also observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect.

Since the deployment of smart meters on a province-wide basis is now nearing completion, the Board stated its expectation that distributors would file for a final review for prudence and disposition of smart meter costs at the earliest possible opportunity following the availability of audited costs. The Board indicated that, for those distributors that are scheduled to file a cost of service application for 2012 distribution rates, the Board expects that they will apply for the disposition of smart meter costs and subsequent inclusion in rate base. For those distributors that are scheduled to remain on IRM, the Board expects these distributors to file a stand-alone application with the Board seeking final approval for smart meter related costs.

(ii) Treatment of Stranded Meter Costs

The Board's *Guideline G-2008-0002: Smart Meters Funding and Cost Recovery* provided two options regarding the accounting treatment of stranded meters. The first option was to leave the stranded meter costs in rate base (i.e. Account 1860) while the second option was to record these costs in "Sub-account Stranded Meter Costs" of Account 1555: Smart Meter Capital and Recovery Offset Variance Account.

In some decisions with respect to 2011 rate applications, the Board indicated that the time to address the recovery of stranded meters is optimal in the 2011 or subsequent cost of service applications, as most distributors have completed or have nearly completed their installation of smart meters. The Board found that the net book value of the stranded meters should be removed from rate base and would be allowed for recovery by means of separate rate riders for the applicable customer classes, rather than by leaving the stranded assets in rate base. The stranded meter costs, for recovery purposes, would be comprised of the gross costs of the stranded meters, less any capital contributions, accumulated depreciation and any net proceeds received from the disposition of the replaced meters. Further guidance is provided in section 3.7 below.

3. Smart Meter Funding and Cost Recovery

3.1 Background

Due to the uncertainty of the technology (for meters, communications infrastructure and data processing and storage), regulatory requirements and responsibilities, and the corresponding capital and operating costs associated with smart meters more than five years ago, the Board adopted a regulatory process whereby smart meter costs are tracked in variance accounts 1555 and 1556.[2] Accounts 1555 and 1556 track smart meter related capital and operating costs respectively.

Revenues generated from the SMFA are recorded separately in a sub-account of account 1555. These funding adder revenues, with simple interest, serve as an offset for the deferred revenue requirement and interest on OM&A and amortization/depreciation expenses, to be recovered when the costs are subsequently reviewed and approved for disposition.

The following table provides a summary of the three mechanisms for smart meter funding and cost recovery that the Board has established.[3]

Table 2: Smart Meter Funding and Cost Recovery Rate Adders and Rate Riders

Title	Acronym	Description
Smart Meter Funding Adder	SMFA	• Mechanism to provide funding before and during smart meter deployment and acts to smooth the rate increases due to smart meter implementation. • First implemented in rates for May 1, 2006. • Initially established at a level of about $0.26/month per metered customer for most distributors; some utilities have had unique SMFA rates due to initial Smart Meter Implementation Plans. Distributors could subsequently apply for a standard SMFA of $1.00 per metered customer per month or a utility-specific SMFA.

[2] Generic Proceeding, 2006 EDR, RP-2005-0020/EB-2005-0529
[3] This conceptualization of the three mechanisms for funding and cost recovery was first documented in Board staff's submission in PowerStream Inc.'s application for Smart Meter disposition [EB-2010-0209], filed on October 1, 2010.

		• SMFA revenues are tracked in a sub-account of Account 1555. Upon disposition, the SMFA revenues and simple interest are used to offset the deferred historical revenue requirement of installed smart meters plus interest on the OM&A and amortization/depreciation expenses, with the variance recovered or refunded through the SMDR. • In many 2011 EDR applications, the Board capped the SMFA at $2.50/month per metered customer. Further, the Board indicated that the SMFA would cease by April 30, 2012.
Smart Meter Disposition Rider	SMDR	• The SMDR recovers, over a specified time period, the variance between: 1) the deferred revenue requirement for the installed smart meters up to the time of disposition; and 2) the SMFA revenues collected and associated interest. • The SMDR should be calculated as a fixed monthly charge. The capital (smart meter, AMI, systems hardware and software) and operating expenses are largely fixed costs and invariant to a customer's demand, and hence should be recovered largely through fixed charges. • In earlier cases the SMDR has been recovered on an equal basis from all metered customer classes, although more recent decisions have dealt with class-specific disposition riders.[4] The distributor should determine and support its proposed allocation, based on principles of cost causality and practicality.
Smart Meter Incremental Revenue Requirement Rate Rider	SMIRR	• When smart meter disposition occurs in a stand-alone application, a SMIRR is calculated as the proxy for the incremental change in the distribution rates that would have occurred if the assets and operating expenses were incorporated into the rate base and the revenue requirement. • The SMIRR is calculated as the annualized revenue requirement for the test year for the capital and operating costs for smart meters. • The SMIRR should be calculated as a fixed monthly charge, similar to the SMDR. • The allocation for the SMIRR should generally be the same as for the SMDR. • The SMIRR ceases at the time of the utility's next cost of service application when smart meter capital and operating costs are explicitly incorporated into the rate base and revenue requirement.

[4] Decision and Order (corrected), [EB-2010-0209], PowerStream Inc., issued November 19, 2010 and Decision and Order, [EB-2011-0128], PowerStream Inc., issued November 21, 2011.

3.2 Smart Meter Funding

The level of the SMFA has varied over the years for each distributor depending on its circumstances. However, generally speaking, the SMFA has taken three forms. For many distributors, the first SMFA was for $0.26/month per metered customer. As distributors began their actual deployments in 2008, many received approval for a standard SMFA of $1.00 per metered customer per month if they demonstrated that they received confirmation from the Fairness Commissioner that they followed the appropriate procurement process. Finally, as distributors began nearing completion of their deployments, many requested and received approval for a distributor-specific SMFA which was calculated using an Excel model that took into account actual costs for deployments and revenues. For most distributors requesting increased SMFAs, the approved SMFA varied from $1.00 to approximately $2.50 per metered customer per month.

Smart Meter Funding Adder, beyond 2011

In decisions for 2011 distribution rates, the Board generally established a sunset date of April 30, 2012 for the termination of the SMFA. Given that all distributors are expected to have completed their smart meter deployment by the end of 2011 or shortly thereafter, the Board considered that further advance funding was no longer warranted. The Board stated its expectation that distributors would file for a final review for the prudence of their smart meter costs at the earliest possible opportunity following the availability of audited costs.

A distributor that wishes to continue the SMFA after April 30, 2012 may apply to do so, but will have to provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted.

Approval of a smart meter funding adder does not constitute regulatory approval of any costs actually incurred to conduct smart meter activities. The prudence of such costs will be examined, and the costs will be approved (or denied), at the time the distributor applies to recover these costs.

3.3 Final Smart Meter Cost Recovery

Cost of Service Applications

The recovery of smart meter capital and operating costs is normally approved (or denied) following a review for prudence and disposition in a cost of service proceeding. A smart meter disposition rate rider ("SMDR") is used to recover the residual revenue requirement that is made up of smart meter costs up to the time of disposition plus interest on the deferred OM&A and amortization/depreciation expenses, less amounts collected through the SMFA and associated interest.[5] The approved gross book value and accumulated depreciation of installed smart meters are then added to rate base, and the test period operating expenses are added to OM&A. This ensures the recovery of the incremental revenue requirement on a going-forward basis through base rates. Further, smart meter capital and operating costs should be reflected in the cost allocation study to ensure an appropriate allocation of costs to the various customer classes.[6]

If a distributor seeks approval for costs related to 100% smart meter deployment, any capital and operating costs for smart meters that are installed beyond the (2012) test year (i.e. for new customers) should not be recorded in Accounts 1555 and 1556.[7]

The Board considers that rates will be fully compensatory when smart meter costs are either incorporated into base rates or recovered by means of the SMIRR. When smart meters are installed for new customers, these customers will pay rates that reflect the recovery of smart meter costs. These additional smart meter costs should be reflected in normal capital and operating accounts,

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[5] This methodology is documented in an Accounting Procedures Handbook FAQ (Frequently Asked Question) issued in August 2008. Specifically, FAQ # 8 shows an example of this approach. The FAQ was also reproduced in Appendix C: Accounting Procedures Handbook – Excerpt of Frequently Asked Questions August 2008 in *Guideline G-2008-0002*.

[6] See Section 2.10 – Cost Allocation of Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011. In particular, section 2.10.3 – Revenue-to-Cost Ratios notes that Smart Meter costs still being recorded (or proposed to being recorded) in Accounts 1555 and 1556 should be excluded from the Cost Allocation analysis. Where a utility is applying for disposition in a Cost of Service application, the Smart Meter capital and operating costs should be included in the cost allocation study, with the costs for the stranded meters being removed from rate base and excluded from the Cost Allocation.

[7] However, account 1555 is still used for tracking the costs of and recovery of the costs related to stranded (conventional) meters. See section 3.6.

akin to other normal distribution assets and costs.

Stand-alone Applications

When rates are adjusted in a stand-alone application, there is no re-evaluation of rate base or of the revenue requirement for the purpose of setting distribution rates. Where the Board approves smart meter capital and operating costs outside of a cost of service proceeding, a SMDR is still required. In addition, a smart meter incremental revenue requirement rate rider ("SMIRR") is established to recover the prospective annualized incremental revenue requirement for the approved smart meters, until the distributor's next cost of service application. The SMIRR continues until the effective date of the distributor's next cost of service rate order, at which time assets and costs are incorporated into the rate base and revenue requirement and recovered on a going-forward basis through base rates.

As in a cost of service application, when smart meter costs are approved for 100% deployment, capital and operating costs for smart meters on a going-forward basis are no longer recorded in Accounts 1555 and 1556; instead the costs are recorded in the applicable capital or operating expense account (e.g. Account 1860 – Meters for smart meter capital assets).

3.4 Costs Beyond Minimum Functionality

While authorized smart meter deployment must meet the requirements for minimum functionality, a distributor may incur costs that are beyond the minimum functionality as defined in O.Reg. 425/06. To date, the Board has reviewed three types of costs that are beyond minimum functionality:

- Costs for technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06;
- Costs for deployment of smart meters to customers other than residential and small general service (i.e. Residential and GS < 50 kW customers); and

- Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.

  Further comments on each of these are provided below.

A. Costs for technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg. 425/06

O.Reg. 425/06 specifies that costs that exceed minimum functionality may be approved by the Board for recovery. In deciding whether technical capabilities of installed smart meters or associated communications or other infrastructure that exceed minimum functionality are recoverable, the Board will consider the benefits of the added technical features and the prudence of these costs. Any distributor seeking recovery for these additional capabilities should provide documentation of the additional technical capabilities, the reasons for them and a detailed cost/benefit analysis.

B. Costs for deployment of smart meters to customers other than residential and small general service

O.Reg. 425/06 defines smart meter deployment as pertaining to residential and small general service customers. The Functional Specification sets the required minimum level of functionality for the AMI to be "for residential and small general service consumers where the metering of demand is not required." As such, minimum functionality has been defined as customers in the residential and general service ("GS") < 50 kW classes.

While some customers in other metered customer classes (GS > 50 kW, Intermediate, Large Use) have interval meters that measure peak demand in a time interval, some distributors may have customers in these classes that have conventional meters and are not eligible for the regulated price plan ("RPP") and therefore are subject to the weighted average spot market price.

A distributor may, as part of its smart meter deployment program, decide to install smart meters for these customers. This could be on the basis that these customers will have higher demand than will typical residential and GS < 50 kW customers, and providing them with better information on how much and when they consume electricity may provide these customers with opportunities for more energy conservation and load shifting. While such meter conversions may generally appear to be logical, they are outside of the regulation and hence are beyond minimum functionality. In other instances, a distributor may convert the meters of interval-metered customers upon repair or re-sealing to "smart" meters that communicate using the AMI infrastructure that the distributor has installed, replacing the existing communications systems for these meters. Again, as these are for meters for customers other than residential and small general service, they are outside of the regulation and hence beyond minimum functionality.

The Board, as part of the Combined Proceeding, approved cost recovery for meter conversions for GS > 50 kW customers for both Toronto Hydro Electric System Limited ("Toronto Hydro") and Hydro Ottawa Limited. However the Board stated:

> The Board is explicitly not finding that the costs associated with these meters fall into the minimum functionality costs. The Board approval of these costs is ancillary to the smart meter decision.[8]

With respect to Toronto Hydro, the Board subsequently approved the recovery of these costs for smart meter installation/conversion for GS > 50 kW customers in Toronto Hydro's 2008-2009 [EB-2007-0681] and 2011 [EB-2010-0142] cost of service rate applications.

Some distributors may be doing "smart meter" conversions for General Service > 50 kW customers upon repair or resealing to enable meter data collection through the AMI infrastructure. While it is recognized that these smart meter installations and conversions are beyond minimum functionality, a distributor may apply for the recovery of such costs. The application should document the nature, the justification and the cost per meter separately from those for the residential and GS < 50 kW customers.

[8] Decision and Order, [EB-2007-0063], August 8, 2007, pg. 20

C. Costs for TOU rate implementation, CIS system upgrades, web presentation, etc.

Costs for CIS systems, TOU rate implementation, etc., are beyond minimum functionality as established by the Board in the Combined Proceeding. However, such costs may be recoverable. In its application, a distributor should show how these costs are required for its smart meter program. Further, a distributor should document how these costs are incremental. For example, if a distributor has a normal budget for maintenance of its billing and CIS systems, costs claimed for system maintenance and upgrades must be shown to be incremental to the normal budget that is already recovered in base rates.

All costs beyond minimum functionality should be clearly identified and supported. Costs that are for meter data functions that will be the responsibility of the Smart Metering Entity will not be recoverable, unless already allowed for per O.Reg. 426/06.[9] Costs for other matters such as CIS changes or TOU bill presentment may be recoverable, but the distributor will have to support these costs and will have to demonstrate how they are required for the smart meter deployment program and that they are incremental to the distributor's normal operating costs.

Cost recovery for ongoing costs of the Smart Metering Entity should not be included in any smart meter cost recovery application, until such time as the Board establishes a cost recovery mechanism. To date, the Board has disallowed requests for either cost recovery or the establishment of a deferral account to track these costs.

[9] Per O.Regs. 393/07 and 426/06, certain utilities that may be working with the SME to test the MDM/R data interface and data validation may have costs for duplicative or overlapping functions for the purposes of testing the MDM/R interface and operations. Such costs will be allowed, subject to a review for the prudence of such costs.

3.5 Evidence to be Filed in Support of Smart Meter Cost Recovery in a Cost of Service Application

When applying for the recovery of smart meter costs, a distributor should ensure that historical cost information has been audited including the smart meter-related deferral account balances up to the distributor's last Audited Financial Statements. A distributor may also include historical costs that are not audited and estimated costs, corresponding to a stub period or to a forecast for the test rate year. The Board expects that the majority (i.e. 90% or more) of the total program costs for which the distributor is seeking recovery will be audited. This threshold should be assessed against total program costs and not the costs in any individual application. In all cases, the Board expects that the distributor will document and explain any differences between unaudited or forecasted amounts and audited costs in its application.

At a minimum, the following information should be provided:

- a report on the status of implementation of smart meters (i.e., how many have been installed and when 100% completion is expected);
- a copy of the letter from the Fairness Commissioner, if applicable, as support that the distributor is authorized for smart metering activities. A general description of contractual arrangements with the selected vendors should be provided.
- capital and operating unit cost per installed smart meter and in total for:
  - procurement and installation of the components of the AMI system;
  - customer information system;
  - incremental operating and maintenance activities;
  - changes to ancillary systems; and
  - stranded meters;
- if applicable, a variance analysis comparing actual costs to previously approved costs;
- identification of and justification for any smart meter or AMI costs incurred to support functionality that exceeds the minimum functionality adopted in O. Reg. 425/06, as discussed in section 3.4 above;
- for any costs incurred that are associated with functions for which the SME has the exclusive authority to carry out pursuant to O. Reg. 393/07,

the basis on which recovery of those costs is allowed under applicable law; and

- a calculation of the SMDR, including the proposed cost allocation methodology.

The onus is on the distributor to support its case, and the distributor should provide any additional information necessary to understand the distributor's costs in light of its circumstances. In considering the recovery of smart meter costs, the Board also expects that a distributor will provide evidence on any operational efficiencies and cost savings that result from smart meter implementation.[10] As an example, meter reading expenses may be reduced with the activation of remote meter reading through the AMI network for residential and small general service customers.

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

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[11].

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

[10] This was first highlighted in the Board's Decision, issued March 3, 2011, with respect to an application by Horizon Utilities Corporation for an increase to its SMFA for 2011, considered under Board File No. EB-2010-0292. Approval of smart meter costs was not sought in the application, but was considered in the concurrent Cost of Service application [EB-2010-0131].
[11] Decision and Order [EB-2011-0128], November 21, 2011, pp. 12-13.

available.

Recognizing that SMFA revenues have been collected from all metered customers since May 1, 2006, the Board's decision in EB-2011-0128 also addressed the treatment of smart meter adder amounts collected from customer classes for which smart meter costs were not incurred, as it related to PowerStream's smart meter deployment program. The Board directed PowerStream to allocate the smart meter adder amounts collected from the GS > 50 kW and Large Use customer classes evenly to the Residential and GS < 50 kW classes when calculating the true-up for the SMDR. The Board concluded that this approach was appropriate because the amounts involved were not significant enough to warrant a more precise allocation.[12] However, for all customer classes for which smart meter costs have been directly incurred, the SMFA revenues plus carrying costs should be directly used as an offset to the incremental revenue requirement to determine the SMDR for that class.

The distributor should also make a proposal for treatment and recovery of stranded meter costs, as discussed in section 3.7.

3.6 Additional Evidence to be Filed when Cost Recovery is Requested in a Stand-Alone Application

When a distributor applies for the disposition of the smart meter variance accounts in a stand-alone application, the distributor should propose both a SMDR and a SMIRR. The SMIRR is assumed to be compensatory during the IRM plan term.[13]

A distributor will need to file the following information in addition to the information listed in section 3.5 above:

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[12] Decision and Order [EB-2011-0128], November 21, 2011, pp. 12-13.
[13] The incremental revenue requirement would actually change over time, due to amortization/depreciation of the assets, and also due to inflation less productivity impacts on operating costs, changes in the Cost of Capital and possibly tax rates. However, it is assumed that the differences are immaterial for the few years until the distributor's next rebasing. As such, the SMIRR will be held constant until rebasing. Upon rebasing, assets and costs will be explicitly reflected in the rate base and revenue requirement, and the SMIRR will no longer be needed.

- calculation of the SMIRR, including the cost allocation methodology. In general, the cost allocation methodology should be the same for both the SMDR and the SMIRR.

A distributor can rely on the order obtained in a stand-alone proceeding in (a) subsequent rate proceeding(s) as evidence that the Board has reviewed and approved the underlying costs. In its next cost of service application, the distributor should include the approved smart meter capital (and associated accumulated depreciation) and annual operating costs in its application, and seek to include the above in its rate base and revenue requirement.

3.7 Stranded Meter Rate Rider ("SMRR")

The regulations provide that distributors be held whole with respect to the cost recovery of stranded meters (i.e. conventional meters replaced as part of the smart meter initiative).

Requirement for Distributors to File Requests for Stranded Meter Costs Recovery

The Board made findings on the treatment and cost recovery for stranded meters in recent decisions[14] which form the basis for the following guidance for distributors seeking recovery of stranded meter costs in future applications. In its EB-2010-0132 Decision and Order on Hydro One Brampton's 2011 cost of service application, the Board stated, among other things, that the time to address the recovery of stranded meters is optimal starting in the 2011 cost of service applications process since most distributors have completed or nearly completed their installation of smart meters and have included a significant portion of these costs in rate base.

Consequently, starting in the 2012 EDR process, distributors seeking recovery of stranded meter costs should bring forward these requests in a cost of service application. It is preferable for the Board to review concurrently a distributor's smart meter and stranded meter costs in the same application where all the required adjustments to the rate base and the revenue requirement are reflected

[14] Hydro One Brampton Networks Inc. (EB-2010-0132) *Decision and Order* of April 4, 2011 and Kenora Hydro Electric Corporation (EB-2010-0135) *Decision and Order* of May 25, 2011

in rates at the same time. Requests for the recovery of stranded meter costs should be in accordance with the guidance provided in this section of the guideline and the cost of service filing requirements previously issued by the Board. Also, the stranded meter costs should be removed from any Cost Allocation run.

While it would be preferable, conceptually, to also deal with stranded meter costs in a non-cost of service (i.e. stand-alone) application, the Board recognizes the practical difficulties that arise since there is no restatement of rate base and base rates. The Board therefore expects that stranded meter costs will be left in rate base until the distributor's next cost of service application.

Determination of when to use Actual or Estimated Stranded Meter Costs

A few distributors fully completed their installation of smart meters in 2010 and all other distributors are expected to complete their installations in 2011. A distributor that files a 2012 cost of service application but who has not completed its smart meter deployment should forecast the stranded meter net book value ("NBV") to the end of 2011 (with appropriate adjustments for depreciation expenses, etc.) to establish the amount requested for recovery. In this situation, if the forecast amount is approved, the distributor would need to true-up this amount as discussed below in Appendix A-1: *Accounting Treatment on Approval of Stranded Meters.*

For a distributor filing a cost of service application after 2012, the requested recovery of stranded meter costs should be on an actual basis as smart meter deployment is expected to be completed by most distributors no later than the end of 2011.

Allocation of Costs, Proposed Recovery Period and Rate Rider

It is expected that a distributor, as part of its application for the disposition of smart meter costs in a cost of service application, will propose (a) rate rider(s) to recover the NBV of the stranded meters.

The recovery period should generally be accelerated (i.e. shorter than the average remaining life of the stranded meters). As a general rule of thumb, the Board expects that the recovery of stranded meter costs should be achievable in a period no longer than four years. The distributor can propose a shorter recovery period, but should take into account rate impacts on its affected customers, and may make proposals to mitigate potential material and adverse impacts. A distributor should provide an explanation for a recovery period longer than four years since the stranded meters are no longer used and useful and the proposed recovery period should, ideally, not go beyond the distributor's next cost of service rate application.

The distributor should determine and support its proposed allocation, based on the principles of cost causality and practicality. The stranded meter NBV should be recovered through rate riders for applicable customer classes. A distributor must outline the manner in which it intends to allocate the stranded meter costs to the applicable customer rate classes and the rationale for the selected approach. If a distributor has recorded the NBV of the stranded meters by customer class, it should propose class-specific rate riders for each applicable class (Residential, GS < 50 kW and any other classes approved by the Board for smart meter deployment). If the NBV is not known on a class-specific basis, a distributor should propose an allocation between the affected metered customer classes and support its proposal.

The charge determinant for the SMRR should be the number of customers, as the stranded meter costs are invariant to a customer's demand or consumption. Thus, the stranded meter rate rider should be a monthly charge applicable for a period of time, and may differ between customer rate classes.

Further information is also provided on stranded meters in Appendix 2-R – Stranded Meter Treatment of Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*, issued June 22, 2011.

4. Smart Meter Model

The Board has made available on its website an updated Smart Meter Model designed for calculating the SMDR and SMIRR. If applicable, the model can also be a vehicle for calculating the SMFA. The updated Smart Meter model is also designed to assist distributors in documenting their smart meter costs.

The model does not deal with allocations between customer rate classes. As noted in section 3.5 above, the Board views that where practical and where the data is available, class-specific SMDRs should be calculated based on cost causality. An allocation on the basis of all metered customers resulting in one uniform rate rider for all metered customer classes would be suitable only where adequate data is not available for the more specific allocation.

If a distributor proposes class-specific SMDRs in its application; it will have to adjust it to its own circumstances.[15]

Whichever method is adopted, the Board is of the view that any cost allocation approach should be consistent between the SMDR and the SMIRR when disposition is sought in a stand-alone application.

Stranded meter costs are dealt with separately. In particular, Appendix 2-R of Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*, updated June 22, 2011, is used for documenting stranded meter costs. The distributor will have to provide its own calculations for the derivation of the stranded meter rate rider(s) as a monthly charge to recover the net book value of stranded meters over the proposed time interval and for the applicable metered customer classes for which there are stranded meter costs, typically from one to four years in duration.

The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious

[15] For example, if a distributor has deployed smart meters to classes other than Residential and GS < 50 kW, it will have to reflect the additional classes in any cost allocation proposal.

review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Appendices

Applicants seeking recovery of smart meter costs, whether through a cost of service or a stand-alone application, should complete Appendices 2-Q and 2-R from Chapter 2 of the *Filing Requirements for Transmission and Distribution Rate Applications*, issued June 22, 2011, and the Smart Meter Model, Version 2.17 issued December 15, 2011, along with this Guideline. The documents and model are found at the following links.

http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Filing_Requirements_Chapter2_Appendices%20-%20Excel.xls

http://www.ontarioenergyboard.ca/OEB/_Documents/2012EDR/2012_smart_meter_model.xls

These spreadsheets and models may be updated from time to time to reflect the most current Board policies and practices with respect to smart meter and stranded meter cost recovery.

Appendix A-1: *Accounting Treatment for Approved Stranded Meter Costs*

Background

There are two accounting treatment options for stranded meters related to the installation of smart meters:

(1) leave them recorded in Account 1860, Meters; or
(2) record them in "Sub-account Stranded Meter Costs" of Account 1555.

In either of these two scenarios, the stranded meter assets are still included in rate base unless the distributor has received approval to remove them from rate base and adjust its revenue requirement accordingly.

These treatment options arose from the Board's letter of January 17, 2007, in which distributors authorized to conduct smart metering activities at the time were directed to record stranded meter costs in "Sub-account Stranded Meter Costs" of Account 1555. Subsequently, in its August 8, 2007 decision in the Combined Proceeding the Board agreed that the stranded meter costs for these distributors should remain in rate base (i.e. Account 1860 – Meters).

The recovery of the stranded meter costs are permitted regardless of which account the stranded meter costs are recorded as indicated in the accounting guidance in the December 2010 Accounting Procedures Handbook FAQs (Q and A #15). However, the distributor may need to make necessary accounting adjustments to conform to the Board-approved methodology for the recovery of stranded meters outlined in this guideline.

Determination of Stranded Meters Net Book Value Eligible for Recovery

The stranded meter NBV eligible for recovery purposes comprise the gross costs of the stranded meters, net of any capital contributions, less the associated accumulated depreciation and any net sale proceeds from the disposition of the stranded meters.

Accounting Treatment of Stranded Meters for 2012 and Beyond

For a distributor that has not previously sought recovery of stranded meter costs, the distributor continues to receive a return on the stranded meter assets included in rate base and continues to recover the meter depreciation expenses in distribution rates. Thus, the recording of depreciation expenses should continue to reduce the NBV of the stranded meters through accumulated depreciation until the end of the fiscal year before the distributor brings forward stranded meter costs for recovery in a cost of service application. For example, if a distributor completed its smart meter deployment in the 2010 fiscal year and then seeks recovery of stranded meter costs in a 2012 application, the depreciation expenses should be recorded up to end of 2011 to reduce the NBV of the stranded meters through the accumulated depreciation as of the end of 2011.

Distributors should make the appropriate adjustments to reflect depreciation expenses and accumulated depreciation for the stranded meters recorded in Account 1860 or 1555 (as applicable) up to the end of the applicable year prior to a request for recovery cited above.

Upon approval of the final rate order, the total stranded costs should be tracked in "Sub-account Stranded Meter Costs" of Account 1555. If the approved amounts are recorded in Account 1860, they should be transferred to this sub-account. The associated recoveries collected from the separate stranded meter rate riders should be recorded in this sub-account to draw down the balance in the sub-account (i.e., the recoveries should not be recorded in Account 1595, Disposition and Recovery of Regulatory Balances Control Account). No interest carrying charges should apply to the sub-account balance prior to the effective date of the rate order approving stranded meter recoveries in rates. Effective on the date of the rate order, interest carrying charges should be calculated on the monthly opening principal balance in the sub-account at the Board prescribed interest rates and recorded separately in the sub-account of Account 1555 (i.e., "Approved Stranded Meter Costs Carrying Charges").

If the distributor has received approval of a forecasted amount for stranded meter costs recovery, the distributor will need to true-up to the actual stranded meter costs when the installation of all smart meters is completed. An adjusting entry should be recorded for this adjustment in the sub-account.

The residual balance (net of recoveries) in “Sub-account Stranded Meter Costs” and the balance in “Approved Stranded Meter Costs Carrying Charges” of Account 1555 should be submitted for review and finalization as part of the distributor’s next cost of service application.

Distributors should maintain records to substantiate the stranded meter costs recovered. Records of items that should be kept include the type and number of each meter type and by customer class, accumulated depreciation, capital contributions and net sale proceeds (if any), to support the stranded meter costs to be recovered.