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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #8

Board Staff

1. General

Issue1.1: Is the Proposed approach to set rates for two years appropriate?

Reference. E1-T2-S1 p3-6

a) When finalizing its plans for 2014 rate setting, did Enersource consider the IRM-Incremental Capital Module (ICM) approach? If not, why not?

b) Did Enersource prepare an analysis that compared the approach proposed in this application with the IRM-ICM one? If so, please provide it.

c) Please indicate the primary purpose of the alternative approach proposed by Enersource (as compared to IRM-ICM). For example is it rate smoothing or the generation of adequate returns on capital investments?

d) What adjustments to Enersource's 2015 IRM-ICM application would be required in the event that: (i) the final model that results from the Renewed Regulatory Framework for Electricity is not materially different from the IRM-ICM and (ii) the Board approves Enersource's 2014 rates based on its proposed alternative approach?

e) Enersource at p.6 states that if its proposed treatment of capital is approved, Enersource will hold flat OM&A levels in rates over the two years, with greater incentive for increased productivity and performance outcomes.

   In that Enersource's 2013 OM&A shows an increase as compared to 2012, what are the two years where OM&A will be held flat?

Response:

a) Enersource is not proposing an approach that makes use of the ICM. Instead, it seeks to recover the cost of capital expenditures for two years: the 2013 Test Year and the 2014 Incremental Capital and Return Year. Enersource is of the view that its proposed approach is just and reasonable because it smoothes the amount of one-time rate increases for rebasing years under the current model, and more accurately provides compensation for the cost of capital.

No, Enersource did not prepare an analysis comparing the approach proposed in this Application, i.e., the ICR, with the existing IRM-ICM.

b) Enersource is of the view that its proposed approach is just and reasonable, serving two primary purposes: it smoothes what are otherwise expected to be step rate increases to customers every rebasing year under the current cost of service rate setting model; and it more accurately provides compensation for the cost of capital.

c) It is not possible to speculate on all of the permutations of what decisions may be made in the Renewed Regulatory Framework for Electricity ("RRFE") and how they may impact Enersource's 2015 rate application. As indicated in the evidence, if approved, Enersource's proposed approach can provide experience and information that may be helpful for the Board in finalizing the RRFE. In addition, the proposed approach does not address a multi-year solution that may interfere with the Board's timing horizon for implementing a new approach.

d) At page 6, lines 19-22 of Exhibit 1 Tab 2 Schedule 1, Enersource states "However, unlike the Straw Man Model, if Enersource's proposed treatment of capital is approved, Enersource will hold flat OM&A levels in rates over the two years, with greater incentive for increased productivity and performance outcomes." Enersource is noting that OM&A is flat or unchanging over the two years 2013 (once adjusted) and 2014.

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory # 4

The Consumers Council of Canada
(CCC)

1 General

1.1: Is the proposed approach to set rates for two years appropriate?

Please explain why, for 2014, the current IRM with the ICM is not appropriate for Enersource. What would be the proposed revenue requirement for 2014 if Enersource followed the Board's IRM with an incremental capital module? Please compare this to Enersource's proposed revenue requirement for 2014.

Response:

Enersource is not proposing an approach that makes use of the ICM because it is of the view that Enersource's proposed approach is more just and reasonable than the ICM model because it smoothes the amount of one-time rate increases for rebasing years under the current model, and more accurately provides compensation for cost of capital.

Please see the response to Board Staff Issue 1.1 Interrogatory 8(b).

EB-2012-0033 **EXHIBIT______**

	B	C / D	E	F	G	H	I	J	K	L	M	N	O
2													
3		**OM&A**	**2008 Board Approved**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**2011 Actual** (IFRS)	**2012 Bridge**	**2013 Test Year**	2013Test Year vs. 2008 Brd. App'd		2013 Test Year vs. 2008 actual	
4										2008-2013	Ave. Annual	2008-2013	Ave. Annual
5	(1)(2)	OM&A Updated	$ 41,653,058	$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,011,000				
6		yearly increase (dec.)		(13.0%)	14.6%	9.8%	11.4%	12.3%	7.0%	46.5%	7.9%	68.4%	11.0%
7	(3)	Smart Meter Component	($1,177,058)	($94,120)	$332,437	($918,558)	($751,218)	($634,685)	($727,000)				
8		OM&A (excluding Smart Meter)	$ 40,476,000	$ 36,140,000	$ 41,856,000	$ 44,680,000	$ 50,032,000	$ 56,374,000	$ 60,284,000				
9		yearly increase (dec.)		(10.7%)	15.8%	6.7%	12.0%	12.7%	6.9%	48.9%	8.3%	66.8%	10.8%
10													
11	(4)	Customers (Ave.)	187,551	185,116	188,136	191,156	193,983	196,534	198,990				
12		Yearly % inc.		-1.3%	1.6%	1.6%	1.5%	1.3%	1.2%	6.1%	1.2%	7.5%	1.5%
13	(4)	Customer& Connections (Ave.)	238,914	236,360	239,713	243,071	246,146	248,978	251,917				
14		yearly increase (dec.)		-1.1%	1.4%	1.4%	1.3%	1.2%	1.2%	5.4%	1.1%	6.6%	1.3%
15													
16	(5)	IRM increase			1.18%	0.18%	0.18%	0.88%					
17													
18		Note1: Includes Property Taxes	$ 897,400	$ 866,050	$ 863,606	$ 867,586	$ 864,465	$ 1,075,000	$ 1,200,000				
19		Note2: reflects Suite Metering Inspection cost Adj. in 2013 ($88k) per IR Issue 4.1 Brd Staff #36 & includes Smart Meters											
20		Note 3: Per Undertaking JT2.11 (OM&A excluding SMART Meter costs in 2008-2012) & see Brd Staff Issue 4.1 No. 34											
21		OM&A per E4-T1-S1 table 1	$ 41,653,058	$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,011,000				
22		<u>less</u> revised table 1 per JT2.11	$ 40,476,000	$ 36,140,000	$ 41,856,000	$ 44,680,000	$ 50,032,000	$ 56,374,000	$ 60,284,000				
23		<u>equals</u> Smart Meter amount	$ 1,177,058	$ 94,120	($332,437)	$ 918,558	$ 751,218	$ 634,685	$ 727,000				
24		Note 4: E3-T1-S2 p.31 attachment 6											
25		Note 5: source: IR Issue 1.1 Brd Staff 10: the cumulative increase over 2009 to 2012 is about **2.4%**										v1 aug.24	
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Table 1: Operating Costs, 2008 to 2013 ($000s)

Business Unit or Key Driver	2008 Rates[1]	2008 Actual	2009 Actual	2010 Actual	2011 Actual CGAAP	2011 Actual IFRS	2012 Bridge IFRS	2013 Test IFRS
Business Unit Summary -								
Health Safety & Security	654	597	606	580	676	676	821	846
Customer Care	7,639	6,653	7,365	8,318	8,014	8,014	8,901	9,317
Engineering & Operations	9,435	8,517	11,399	11,821	12,229	12,229	13,062	13,923
Metering	2,157	756	374	1,632	2,295	2,295	2,356	2,017
Exec, Admin & Corp Alloc'n[2]	9,980	9,921	10,664	10,823	11,171	11,171	11,785	12,574
ISTS	5,457	4,477	4,971	5,862	6,279	6,279	7,559	8,227
Regulatory Affairs	1,074	898	1,053	1,215	1,340	1,340	1,473	1,518
Facilities Management	1,488	1,378	1,157	811	991	991	1,420	1,377
Other Expenses	2,194	1,767	2,681	1,734	1,437	1,437	1,876	1,904
Business Unit Sub-Total	**40,078**	**34,964**	**40,271**	**42,796**	**44,432**	**44,432**	**49,253**	**51,703**
Other Key Drivers -								
IFRS Overhead Burdens	-	-	-	-	-	2,525	3,022	2,774
Bad Debt Expense	1,575	1,270	1,253	2,802	3,706	3,706	3,600	3,550
Asset Mngm't Plan Initiative	-	-	-	-	120	120	287	1,153
New Administration Building	-	-	-	-	-	-	847	1,668
One-Time Costs	-	-	-	-	-	-	-	251
Other Key Drivers Sub-Total	**1,575**	**1,270**	**1,253**	**2,802**	**3,826**	**6,351**	**7,756**	**9,396**
Total Operating Costs	**41,653**	**36,234**	**41,524**	**45,598**	**48,258**	**50,783**	**57,009**	**61,099**

1. OM&A for 2008 Rates has been adjusted to include smart meter costs of $1,177. Note that this differs from Table 1 of Exhibit 2 Tab 1 Schedule 4, which agrees with EB-2007-0706 Settlement Agreement dated December 21, 2007, page 16.
2. "Exec, Admin & Corp Alloc'n" consists of Enersource Executive and Administration, and Shared Services/Corporate Allocation.

The total operating costs will rise from $41,653, as approved by the Board for 2008, to $61,099 in the 2013 Test Year. This is an increase of $19,446, or 47%.

Table 2 below identifies the cost variances since 2008 that are attributable to business units and to other key drivers.

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Undertaking No. JT2.11

To produce Table 1 unadjusted for smart-meter-related costs. P. 86

Business Unit or Key Driver	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual CGAAP	2011 Actual IFRS	2012 Bridge IFRS	2013 Test IFRS
Business Unit Summary -								
Health Safety & Security	654	597	606	580	676	676	821	846
Customer Care	7,639	6,653	7,365	8,318	8,014	8,014	8,901	8,975
Engineering & Operations	9,435	8,517	11,399	11,821	12,229	12,229	13,062	13,923
Metering	980	662	707	714	1,544	1,544	1,721	1,632
Exec, Admin & Corp Alloc'n[1]	9,980	9,921	10,664	10,823	11,171	11,171	11,785	12,574
ISTS	5,457	4,477	4,971	5,862	6,279	6,279	7,559	8,227
Regulatory Affairs	1,074	898	1,053	1,215	1,340	1,340	1,473	1,518
Facilities Management	1,488	1,378	1,157	811	991	991	1,420	1,377
Other Expenses	2,194	1,767	2,681	1,734	1,437	1,437	1,876	1,904
Business Unit Sub-Total	**38,901**	**34,870**	**40,603**	**41,878**	**43,681**	**43,681**	**48,618**	**50,976**
Other Key Drivers -								
IFRS Overhead Burdens	-	-	-	-	-	2,525	3,022	2,774
Bad Debt Expense	1,575	1,270	1,253	2,802	3,706	3,706	3,600	3,550
Asset Mgm't Plan Initiative	-	-	-	-	120	120	287	1,153
New Administration Building	-	-	-	-	-	-	847	1,668
One-Time Costs	-	-	-	-	-	-	-	251
Removal of IMS costs[2]								(88)
Smart Metering Costs[3]								727
Other Key Drivers Sub-Total	**1,575**	**1,270**	**1,253**	**2,802**	**3,826**	**6,351**	**7,756**	**10,035**
Total Operating Costs	**40,476**	**36,140**	**41,856**	**44,680**	**47,507**	**50,032**	**56,374**	**61,011**

1. "Exec, Admin & Corp Alloc'n" consists of Enersource Executive and Administration, and Shared Services/Corporate Allocation.
2. Deferral account requested for IMS costs.
3. 2013 SM operating costs have been included in this table. Previously these costs were funded through the rate adder.

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #36

Board Staff

4. Operating Costs

Issue 4.1: Is the proposed 2013 and 2014 OM&A forecast appropriate?

Reference: E 4-T1-S6 p.6

Regarding the costs of inspecting (certifying) installed suite meters, Enersource notes that $141k will be incurred in 2012 and $211k in 2013. Enersource indicates that that in the calculation of its 2013 revenue requirement, it excluded $211k, from the 2013 Test Year OM&A costs, but included $88k, representing one quarter of $352k, the total one-time certification costs.

a) Are the meter inspections or certification costs for newly installed meters normally charged to OM&A or to capital?

b) Did Enersource request the establishment of a variance (or deferral) account to record the $141k in costs which will be incurred in 2012 for future recovery in 2013 and 2014?

c) Please explain why it is appropriate to charge ratepayers in 2013 and 2014 for meter inspection OM&A costs that were incurred in 2012?

Response:

a) Meter inspections or certification costs for newly installed meters are normally charged to capital. However, Enersource has 26 existing IMS buildings that were not previously inspected, and the meter inspections have to be completed to achieve Measurement Canada's SE-04 certification. Since those meter inspection (certification) costs are "one-time" in nature, they are charged to OM&A.

b) Enersource did not request the establishment of a variance account to record the one-time costs of $141 that will be incurred in 2012. Enersource believes that the costs would be expensed under IFRS and that it would simply seek recovery of the costs in 2013. Since the recognition of the expense and

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recovery of the costs would be occurring very close together there would be no need to charge interest on the account.

However, Enersource is still negotiating the contract for the certification work and has not incurred any expenses year-to-date June 2012. Enersource has also received an extension from Measurement Canada to perform the work over a three-year period. Enersource will remove the request for recovery and will be seeking approval of a deferral account to track the expenses and will seek recovery during its next cost of service rate application.

c) Prior to 2012, there were no clear rules or regulations explained to distributors regarding the need to inspect/certify installed suite meters. In 2012 Enersource was made aware by Measurement Canada that it was required to complete meter inspections to achieve SE-04 certification for existing IMS buildings.

As stated in response b) above, Enersource will be requesting a deferral account to track the expenses instead of seeking recovery at this time.

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #10

Board Staff

1. General

Issue 1.1: Is the Proposed approach to set rates for two years appropriate?

Reference: E1- T1- S1 p3

The evidence states that "The Board's current rate setting model has resulted in nominal rate increases via incentive regulation mechanism ("IRM") since Enersource's last COS rate application for the 2008 rate year. During this period, Enersource has continued to invest in essential capital infrastructure in order to deliver on the Company's mission to consistently fulfill and exceed customer needs and stakeholder requirements".

Please provide the nominal increase (expressed as a %) for each of 2009, 2010, 2011 and 2012.

Response:

Since Enersource's last COS rate application for the 2008 rate year, Enersource has received the following nominal rate increases via IRM:

	2009	2010	2011	2012
IRM Price Cap Index	1.18%	0.18%	0.18%	0.88%

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Ontario Energy Board

Commission de l'énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

Ontario Energy Board

Chapter 1 of the Filing Requirements For Electricity Transmission and Distribution Applications

June 28, 2012

including the impact on the distributor's customers and its cash flow position, and other matters such as intergenerational equity. No carrying charges will be applied to the balance in the PP&E account.

For an applicant that files a 2013 cost of service application on the basis of MIFRS:

- The applicant must provide evidence that indicates the IFRS-CGAAP Transitional PP&E Amount is to be cleared in rates as follows:
    - an adjustment to the test year depreciation expense (Appendix 2-CD or Appendix 2-CH, 2013 MIFRS Depreciation Expense) as part of distribution expenses for the amortization of Account 1575, and
    - an adjustment to the test year revenue requirement as part of the return on rate base component. The applicant must not record the return on rate base component in Account 1575 for accounting purposes.
- The Fixed Asset Continuity Schedule (Appendix 2-B) in the rate application must not be adjusted for balances related to the IFRS-CGAAP Transitional PP&E Amount.
- The applicant must provide a breakdown of the balance related to the IFRS-CGAAP Transitional PP&E Amount that is effective on the transition date to MIFRS. The applicant must provide the supporting analysis of the amounts in this account by completing Appendices 2-EA or 2-EB. The drivers of the change in closing net PP&E (CGAAP versus MIFRS) must be identified and quantified.

2.12.5 Disposition of Deferral and Variance Accounts

The applicant must:

- Identify all accounts for which it is seeking disposition;
- Identify any accounts for which the applicant is not proposing disposition and the reasons why;
- Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year; if the applicant is proposing an alternative recovery period, an explanation should be provided;
- Indicate if the balances proposed for disposition before forecasted interest match the last Audited Financial Statements and provide explanations for any variances;
- Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period; and

- Establish separate rate riders to recover the RSVA Power Account Global Adjustment from non-RPP customers.

In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:

- Causation - The forecasted expense must be clearly outside of the base upon which rates were derived.
- Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence - The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

2.12.6 Smart Meters

If the applicant is applying for smart meter-related recoveries, the applicant should refer to *Guideline G-2008-0011: Smart Meter Funding and Cost Recovery – Final Disposition*, or any successor document issued by the Board, with respect to any proposal to dispose, or partially dispose balances in accounts 1555 and 1556. In support of such proposals, the applicant must provide a completed smart meter model.

For those distributors that were subject to an IRM-based rate adjustment for their 2011 rates, the Board approved the continuation of any Smart Meter Funding Adder ("SMFA") to be in effect until no later than April 30, 2012. The Board has upheld the cessation of the SMFA as of April 30, 2012 in most decisions for 2012 IRM applications. The Board stated that distributors would be expected to file for a final prudence review of the costs in the smart meter variance accounts at the earliest possible opportunity following the availability of audited costs, since the deployment of smart meters on a province-wide basis is now nearing completion. Distributors scheduled to file cost of service applications for 2013 or later would be expected to apply for the disposition of smart meter costs, subsequent inclusion in rate base, and for recovery of stranded costs, in that application, if not previously addressed in a prior stand-alone or cost of service application.

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Ontario Energy Board

Ontario

EB-2008-0408

Addendum to Report of the Board:

Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment

June 13, 2011

The Board believes that in general, the account should be cleared at the first rebasing under MIFRS, while recognizing that some portion of the amount for which clearance is sought is based on a forecast. In individual cases where a real concern exists regarding the reliability of the forecast numbers, the Board may decide to clear only a portion of the balance, and await actual results for the clearance of the remainder of the account.

Applicability of the Account to Cost of Service Applications

Hydro One proposed that the PP&E deferral account should be available to utilities as part of a cost of service application. Hydro One provided the example of a utility that adopts IFRS on January 1, 2012, but has effectively had to adopt IFRS on January 1, 2011, the comparative year. This utility would still be under CGAAP for rate purposes in 2011, and would therefore have differences driven by the IFRS transition in its 2012 opening PP&E balances.

The Board acknowledges that the proposed account has relevance for utilities making cost of service applications and therefore sees no reason to restrict its application to IRM applications.

P&OPEB Account

The staff paper recommended that no generic deferral account for differences in P&OPEB costs should be granted, noting that many of utilities rate-regulated by the Board are participants in the Ontario Municipal Employees Retirement System pension plan, which is not expected to be materially affected by the changes associated with IFRS, and few utilities would have other post-employment benefit plans that would be significantly affected. The staff paper suggested that utilities with defined benefit plans and/or other post-employment benefit plans that expect to experience a large cost impact may apply to the Board on an individual basis for a deferral account.

Contrary to the recommendation in the staff paper, the CLD and the EDA recommended the creation of an additional generic account to capture differences in P&OPEB amounts caused by the transition to IFRS. If such an account were created, it could be structured and operated in much the same fashion as the deferral account for PP&E.

The CLD was concerned that if a generic account is not established, the adjustment to P&OPEB liability at the date of transition to IFRS may never be reflected in rates. The CLD submitted that affected utilities transitioning to IFRS may be required to immediately recognize actuarial gains and losses as an adjustment to opening retained earnings at the date of transition. The CLD agreed that only a few large distributors will experience a large change in their P&OPEB balances, but the impact may be significant for some distributors. The EDA pointed out that the creation of a generic account would reduce the administrative burden on the Board of dealing with applications for such an account from individual utilities.

No ratepayer representative supported the creation of a P&OPEB deferral account. Hydro One and EGD supported the Board staff recommendation that individual utilities could apply for such an account if they anticipate large impacts in P&OPEB accounts on transition to IFRS. Hydro One submitted that given the different P&OPEB plan types, utility sizes and accounting methods in use, a generic approach is not warranted.

The Board will not approve the creation of a generic account for IFRS related impacts on P&OPEB accounts occurring at the date of transition. As acknowledged by the CLD, the impacts are anticipated to be significant for only a few large utilities. The option remains for these utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

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Appendix A: Summary of Board Policy in this Addendum

Issue 1

Information supporting rate adjustments during an IRM period should be provided in the same basis of accounting as the information upon which the rates were set. This means that if rates were set on CGAAP, the financial information supporting the adjustment must be provided under CGAAP, and the adjustment to rates will be made on the basis of the CGAAP filing.

In addition, a reconciliation of the CGAAP-based financial information mentioned above to the relevant information in the last annual RRR reporting under modified IFRS is required. Where the distributor has adopted IFRS for financial reporting but has not yet made an annual RRR reporting under modified IFRS, the financial information mentioned above must be provided in both CGAAP and modified IFRS format, and a reconciliation provided between the two accounting standards.

No third party assurance is required for the reconciliations, although an applicant can choose to file such assurance as part of its evidence supporting the reconciliation.

Issue 2

The Board authorizes the creation of a generic IFRS transition PP&E deferral account to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS as follows (for purposes of this account, PP&E includes rate base related intangible assets.):

1. Utilities shall maintain records using CGAAP of the amounts in the PP&E accounts that will be included in rate base, commencing at their last rebasing under CGAAP, and continuing until their first rebasing under MIFRS. This will produce a figure for the PP&E accounts that is consistent with their last rebasing. Records should be kept to at a level of detail sufficient to support the analysis and justification of the entries made to the account.

2. Utilities shall also calculate "adjusted rate base" values for the PP&E components of rate base using the accounting system applicable in each year

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between rebasing under CGAAP and the first rebasing under MIFRS. For example, if a utility rebased using CGAAP in 2010, and continued with CGAAP in 2011, and then moved to IFRS for financial reporting for 2012 and 2013, it would calculate the PP&E components of rate base using CGAAP in 2010 and 2011, and MIFRS in 2011, 2012 and 2013. (2011 must be included in MIFRS because the year before the move to IFRS has to be restated under IFRS.)

3. Utilities shall record in the deferral account the cumulative difference between items 1 and 2 above. The calculations for the balance in this account (which does not accrue carrying charges), will provide the Board with the evidence to consider an adjustment to the opening values of the PP&E components of rate base up or down in the first MIFRS rebasing year to match the "adjusted rate base" figure above. For that rebasing year, and every subsequent year, rate base will be calculated on a MIFRS basis.

4. The amount of the cumulative adjustment up or down (unamortized balance of the deferral account) should be recorded as a balance to be recovered from, or refunded to, ratepayers and as an adjustment to opening rate base in the year of rebasing (with rate base otherwise calculated on an MIFRS basis).

5. Utilities shall reflect the deferral account balance as an adjustment to MIFRS calculated rate base going forward, and amortize that adjustment over a period of time approved by the Board. The rate base, upon which the utility return on rate base calculation is based in the cost of service application, will therefore include two components: the MIFRS based elements of PP&E; and, the unamortized balance in the deferral account. Thus the unamortized balance in the deferral account will attract the same level of return in determining revenue requirement in a cost of service application as other PP&E balances.

The Board will determine the period of time for amortization on a case-by-case basis and will be guided primarily by such considerations as the impact on rates, implications of any other IFRS transition matters and any requirements for rate mitigation.

Amortization of the adjusting amount, up or down, shall be reflected in any applicable rate application as an adjustment to depreciation expense (the refund or recovery of the amount of the adjustment over time) and the return on rate base calculation on the

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unamortized balance shall be included in applicable revenue requirement calculations in the same way as for any other component of rate base.

Utilities must propose the level and pattern of recovery in rates of the amounts in the account for consideration by the Board in their next cost of service application after adopting IFRS. In general, the account will be cleared at the first rebasing under MIFRS. In individual cases, the Board may decide to clear only a portion of the balance, and await actual results for the clearance of the remainder of the account.

The Board will not approve the creation of a generic account for IFRS related impacts on P&OPEB accounts occurring at the date of transition. The option remains for utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

Issue 3:

The Board will not create or define a specific account for IFRS impacts on taxes or PILs. Board staff and industry participants should monitor developments in this area and notify the Board should a specific need for additional guidance from the Board emerge.

Issue 4:

The Board requires a utility that adopts USGAAP or an alternate accounting standard other than IFRS, in its first cost of service application following the adoption of the new accounting standard, to:

- demonstrate the eligibility of the utility under the relevant securities legislation to report financial information using that standard;
- include a copy of the authorization to use the standard from the appropriate Canadian securities regulator (if applicable); and
- set out the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

If a utility is required to transition to IFRS for financial reporting purposes a few years after adopting USGAAP, the Board will carefully scrutinize the costs incurred to

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory # 55

Board Staff

9. Modified International Financial Reporting Standards

9.1 Is the treatment and disposition of the Property Plant & Equipment adjustments due to the transition to MIFRS appropriate?

Ref: E2-T1-S1, p.16 and E9-T1-S1, p.18-19

Per the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism (EB-2008-0408) dated June 13, 2011, the Board approved a generic deferral account to capture PP&E differences arising only as a result of the accounting policy changes caused by the transition from CGAAP to MIFRS. The operation of the deferral account is set out in Appendix A of the report.

In relation to the transition to IFRS regarding PP&E, Enersource is proposing to refund customers over a one year period commencing January 1, 2013 through a separate rate rider. This treatment is different than the Board approved treatment, where page 32 of the Addendum to the Report of the Board states:

> Amortization of the adjusting amount, up or down, shall be reflected in any applicable rate application as an adjustment to depreciation expense (the refund or recovery of the amount of the adjustment over time) and the return on rate base calculation on the unamortized balance shall be included in applicable revenue requirement calculations in the same way as for any other component of rate base.

Please explain the rationale of why Enersource is requesting to deviate from Board guidance:

- o requesting for a new variance account instead of using Account 1575 IFRS-CGAAP Transitional PP&E Amounts as per the APH, and
- o refunding customers over a one year period over a separate rate rider rather than clearing the PP&E deferral account through a one time adjustment to rate base

Board staff noted that Enersource has included CWIP in the calculation of PP&E differences arising from the transition to MIFRS, even though CWIP is not included in the rate base.

Please revise and recalculate the PP&E differences excluding CWIP, arising from the result of the IFRS transition using Board approved methodology by completing the schedules noted in Board staff interrogatory number 5 under Filing Requirements.

Response:

Enersource confirms that PP&E differences arising only as a result of the accounting policy changes caused by the transition from CGAAP to MIFRS will be recorded in Account 1575 IFRS-CGAAP Transitional PP&E Amounts.

Enersource has requested a refund period of one year to reduce the intergenerational inequities for customers compared to a one-time adjustment to rate base that would effectively refund customers over a four-year period. Furthermore, a one-year disposition period would help mitigate rate volatility caused by the recovery of stranded meter costs over that same period. Lastly, a one-year disposition period would more closely align with the length of time over which the IFRS-CGAAP transitional differences arose.

A separate rate rider has been requested to more accurately track the amount refunded so that both Enersource or customers are not negatively impacted by an over/under refund based on billing determinants.

The IFRS – CGAAP transitional difference calculated for both 2011 and 2012 captured the difference between net fixed assets including cumulative overheads in CWIP balances of $220. Enersource has recalculated this transitional difference to exclude CWIP balances as presented in Appendix 2-EA, PPE Deferral account.

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Appendix 2-EA
IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$				
PP&E Values under CGAAP								
Opening net PP&E - Note 1			453,053,965	467,850,354				
Additions (including disposals/retirements)			49,183,927	66,328,843				
Depreciation (amounts should be negative)			(34,387,539)	(36,409,961)				
Closing net PP&E (1)			467,850,354	497,769,236				
PP&E Values under MIFRS (Starts from 2011, the transition year)								
Opening net PP&E - Note 1			453,053,965	474,514,796				
Additions (including disposals/retirements)			46,909,059	63,287,087				
Depreciation (amounts should be negative)			(25,448,228)	(26,991,423)				
Closing net PP&E (2)			474,514,796	510,810,461				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)			(6,664,442)	(13,041,225)				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance			-	(6,664,442)	(13,041,225)	-	13,041,225	26,082,449
Amounts added in the year			(6,664,442)	(6,376,782)				
Sub-total			(6,664,442)	(13,041,225)	(13,041,225)	-	13,041,225	26,082,449
Amount of amortization, included in depreciation expense - Note 2					13,041,225	13,041,225	13,041,225	13,041,225
Closing balance in deferral account			(6,664,442)	(13,041,225)	-	13,041,225	26,082,449	39,123,674

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	(13,041,225)	**WACC**	6.582%	
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	(858,373)	**Period - Note 4**	1	Years
Amount included in Revenue Requirement on rebasing (excluding PILS)	(13,899,598)			
PILS	(171,414)			
Amount included in Revenue Requirement on rebasing (including PILS)	**(14,071,013)**			

Notes:

1 For an applicant that adopts IFRS on January 1, 2012, the PP&E values as of January 1, 2011 under both CGAAP and MIFRS should be the same.

2 Amortization of the deferred balance in Account 1575 will start from the rebasing year.
Assume the utility requests for a certain disposition period, the amortization that should be included in the depreciation expense is calculated as:
the opening balance of Account 1575 / the approved disposition period

3 Return on rate base associated with deferred balance is calculated as:
the deferred account opening balance as of 2013 rebasing year x WACC
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

4 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to ratebase to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

Note: All Balances shown in the table exclude CWIP balances

In addition to the amount shown above, Enersource is seeking approval to dispose of the corresponding decrease in revenue requirement as a result of the $12,821 decrease in rate base in 2013. Table 13 details the impact on 2013 revenue requirement.

Table 13: Impact of MIFRS on Revenue Requirement ($000s)

		2013	
Decrease to rate base	$	(12,821)	(A)
Return on capital		6.58%	
	$	(844)	
Decrease in PILs	$	(160)	
2013 Revenue requirement to be refunded	$	(1,004)	(B)
Total Amount to be Refunded	$	(13,825)	(A) + (B)

In summary, due to the transition to IFRS in relation to fixed assets, Enersource is proposing to refund a total of $13,825 to customers over a one-year period commencing January 1, 2013 through a separate rate rider and is requesting it to be tracked in a new variance account.

Other Comprehensive Income MIFRS Post-Employment Adjustment

Enersource is requesting a deferral account to capture the impact of the post-employment adjustment resulting from the transition to MIFRS. Upon adoption, Enersource was required to record all re-measurements at the date of transition to MIFRS as opening adjustments to retained earnings. Under CGAAP, a portion of this amount would have been recorded as an expense each year and would have been recovered in distribution rates through OM&A. The net impact to Enersource at the date of transition was a reduction of the post-employment accrued liability of $150.

Enersource is also requesting that the new deferral account be used for future re-measurements of the defined benefit obligation which will be recorded in Other Comprehensive Income ("OCI") instead of being amortized in OM&A using the corridor approach under CGAAP. For 2011, the actuary loss relating to the post-employment obligation was $769. For further details of the impact of MIFRS on post-employment benefits refer to Exhibit 1 Tab 3 Schedule 1.

In total, Enersource is seeking to recover from customers $619 over a one-year term. Due to the amount requested for disposition, a recovery period of longer than one year would result in a $0.000/kWh rate rider for certain customer classes. See Table 14 below. Actuary gains and losses that are recognized in OCI between the end of 2012 and the next cost of service rate application will be tracked in the deferral account and will be refunded or recovered in future rates.

Table 14: OCI MIFRS Post-Employment Adjustment ($000s)

Description	Accounting Impact
Enersource Portion of IFRS Transition	$(150)
Enersource 2011 Portion of OCI Re-Measurements	769
Total to be Recovered Over One Year	**$ 619**

Accounts Not Proposed for Clearance

All deferral and variance account balances as at December 31, 2011 are being requested for disposition except for:

i. Account 1595 (2009) as the rate riders pertaining to disposition of this account are effective until January 31, 2012; and

ii. Account 1595 (2010) as the rate riders pertaining to disposition of this account are effective until January 31, 2014.

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #56

Board Staff

9. Modified International Financial Reporting Standards

Issue 9.2 - Are the proposed new MIFRS deferral and variance accounts appropriate?

Reference: E9-T1-S1, p. 19 and E1-T4-S1, p.1

Enersource is requesting a deferral account to capture the impact of the post-employment adjustment resulting from MIFRS. The net impact at the date of transition was a reduction of the post-employment accrued liability of $150,000.

Per the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism (EB-2008-0408) dated June 13, 2011, page 15:

> The Board will not approve the creation of a generic account for IFRS related impacts on P&OPEB accounts occurring at the date of transition. The option remains for these utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

a) Enersource's materiality threshold is $645,000. The net impact at the date of transition is a reduction of the post-employment accrued liability of $150,000. Please demonstrate how there is a large cost impact to Enersource from the $150,000.

b) Please provide supporting documentation (e.g. actuarial valuation report) to support the $150,000 reduction in post-employment accrued liability.

Response:

a) Due to the transition to IFRS, Enersource is requesting a new deferral account for Post-Employment Benefits as Enersource is unable to forecast whether any actuarial gain or loss will be recognized in any given year. Further, IFRS requires Enersource to obtain an annual valuation and recognize actual gains or losses immediately into income or expense as per IFRS IAS19R.

Enersource is requesting a variance account to track these actuarial gains and losses between cost of service applications. Enersource's intent is that the variance account would be cleared similar to the corridor method.

Enersource recorded a reduction of the post-employment benefit accrual of $150 at the date of transition. However due to the requirements under IFRS, Enersource recorded an expense of $769 at December 2011 relating to the re-measurement of the post-employment liability based on Enersource's actuarial report. Enersource is requesting to dispose $619, the net of these two amounts, in this Application.

b) Attached to this response is Enersource's Actuarial Evaluation as at January 1, 2011. Per the report, Enersource's consolidated post-employment accrued liability as at January 1, 2011 was $4,496 (p. 5 of report). As at December 31, 2010, Enersource's post-employment accrued liability per Enersource's audited consolidated financial was $4,656. Therefore, Enersource consolidated IFRS opening day adjustment for its post-employment accrued liability was $160. Please see the tables below for the allocation of this amount amongst Enersource Corporation and its affilliates.

Post-Employment Accrued Liability	December 31, 2010[1]	January 1, 2011[2]
Enersource Hydro Mississauga	$3,783	$3,654
Enersource Corporation	624	601
Enersource Hydro Mississauga Services	249	241
Total post-employment liability	**$4,656**	**$4,496**
Change (consolidated)		$(160)

Enersource Hydro Mississauga Post-employment accrued liability Opening Day Adjustment	January 1, 2011[2]
Enersource Hydro Mississauga (per above: $3,783 – $3,654)	$129
Allocation of 95% of Enersource Corporation's portion to Hydro (management fee) ((per above ($624-$601)*95%))	21
Enersource Hydro Mississauga reduction in its liability	**$150**

Notes:

1. Based on Enersource's audited consolidated financial statements as at December 31, 2010.

2. Allocation of the $160 amongst the companies is based on December 31, 2010 total active headcount.

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Ontario Energy Board

Ontario

EB-2009-0349

Report of the Board

Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09

June 10, 2010

benefit assessment as explained below, while essentially all distributors required to file a Detailed GEA Plan will be required to undertake a detailed direct benefit assessment. However, if a distributor that files a Detailed GEA Plan falls below the threshold once all Smart Grid capital costs are excluded, that distributor will be permitted to use the standardized approach since Smart Grid costs are not relevant for the purpose of this framework.

Any distributor that is permitted to use the standardized approach will be provided with the option to undertake a detailed direct benefit assessment.

3.2.2.3 Basic Benefit Assessments for Basic GEA Plans

The Board will use an ongoing weighted average of actual direct benefits (relative to total eligible investment costs) associated with all distributors that have completed a detailed direct benefit assessment. As this is an evolutionary framework, it is the intent of the Board that the percentage used in the standardized approach will be refined over time as experience is gained and more distributors complete a detailed benefit assessment. For example, this may take the form of different percentages for different investments in the future.

At this time, only Hydro One Distribution has completed a detailed direct benefit assessment. The Board agrees with the comment that the Hydro One estimates of the direct benefits have an empirical basis and are based on a large number of projects, and therefore can be used as a transitional step in this evolutionary framework for distributors permitted to use the standardized approach. However, the Board does not believe the suggested use of a single percentage (i.e., 15%) for all eligible investments would be appropriate. The percentages of direct benefits differ for Expansion and Renewable Enabling Improvement (REI) investments, as Expansion investments tend to benefit load customers more than REI investments.[9] In addition, distributors will have different relative proportions of such investments. As such, separate percentages for Expansion and REI investments will be utilized to provide a more accurate estimate of the direct benefits.

Absent the information limitations identified during the consultation process, the Board would have been hesitant to use the Hydro One Distribution percentages of direct benefits in relation to REI and Expansion investments for other distributors. However, aside from the number of projects, the characteristic that differentiated Hydro One Distribution most from other distributors is customer density and it was learned in this consultation process that no distributors, including Hydro One, have such information specific to different areas in their service territories. The number of projects is also not a factor at all in the determination of direct benefits associated with an investment. As such, the Board is of the view that the percentages that are ultimately approved for

[9] For example, based on the provisionally approved methodology and allocation (i.e., dollar amounts) proposed by Hydro One as part of its 2010 and 2011 distribution rates application, those dollar amounts represent 6% for REI investments and 17% for Expansion investments.

Hydro One Distribution[10] in relation to Expansion and REI investments should provide a reasonable estimate for other distributors until more distributors complete detailed benefit assessments and a rolling weighted average can be used, particularly given the limited amount of eligible investments expected in Basic GEA Plans.

The Board has only approved the allocation of costs proposed by Hydro One, on a provisional basis, at this time. The Board's Partial Decision notes that "the allocation methodology and the resulting responsibility for Green Energy Plan costs for 2010 and 2011 will be subject to later revision to reflect the Board's final policy determination in EB-2009-0349." As such, the percentages that are initially to be used by distributors undertaking a basic benefit assessment will be the percentages based on the methodology and allocation that are approved by the Board on a final basis subsequent to the issuance of this Board Report. Those revised percentages will be communicated by the Board when they become available.

As noted above, in the future, the Board will use an ongoing weighted average of actual direct benefits associated with all distributors that have completed a detailed direct benefit assessment. As the percentages are updated to reflect changes in this ongoing weighted average, the updated percentages will only apply to incremental eligible investments for which the Board has not yet determined the direct benefits. In other words, the Board will not make future adjustments to previous calculations of direct benefits that have already been approved by the Board to reflect changes in the weighted average.

Consistent with the Board's interpretation of O. Reg. 330/09 above, the calculation of this category of direct benefits will also be on either an *ex post* basis or on an *ex ante* basis with a variance or deferral account.

3.2.2.4 Detailed Benefit Assessments for Detailed GEA Plans

As noted above, distributors required to file a Detailed GEA Plan will be expected to undertake a detailed direct benefit assessment based on the principles and criteria set out below unless the total capital costs in the plan are below the threshold once all Smart Grid capital costs have been excluded.

Guiding Principles

The Board generally agrees with the principles that were identified in the Discussion Paper with some modifications to reflect certain stakeholder comments.

In relation to the first principle, the Board agrees with the comment that it is important to clarify "load" customers and "eligible" investments.

In regard to the second principle, a number of stakeholders commented that the circumstances of the distributor should not be related to the size of the distributor in

[10] EB-2009-0096.

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #19

Board Staff

2. Rate Base

Issue 2.3 – Is the proposed Green Energy Act Plan appropriate?

Reference:
Exhibit 2/Tab2/Sch3/Appendix1/p.14/ 4.3 Direct Benefits to Customers; (b) Report of the Board, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09, Paragraph 1.1, Regulation 330/09;

(c) Exhibit 2/Tab2/Sch3/Appendix1/p.8/ 3.4 Expenditures Related to Renewable Generation Connections;

(d) Exhibit/Tab2/Sch3/Appendix1/p.11/ 4.2.3 Continuing Capital Expenditures; (e) Filing Requirements, Part VII, Capital and OM&A Deferral Accounts for Renewable Generation Connection or Smart Grid Development;

(f) Report of the Board, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09, Paragraph 3.2.2.3, Basic Benefit Assessments For Basic GEA Plans;
(g) Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-2009-0397].

In spite of the implementation of the GEA plan and evidence regarding REI and expansion work, reference (a) states that:

Enersource has not undertaken any projects where costs may be recovered from provincial ratepayers, and does not forecast any projects in this category during the next 5 years.

With respect to reference (b), on OM&A costs, the *Framework for Determining Direct Benefits* clarifies that:

There is therefore a relationship between the eligible investments costs and the associated direct benefits. [...]

"Eligible investment" costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, are not limited to only the initial capital investment costs but also include the *up-front* OM&A costs necessary for the purpose of "enabling the connection of a qualifying generation facility". However, given that section 79.1 focuses solely on the initial investment, ***ongoing OM&A costs that are incurred by the distributor after the investment has been made will not be eligible for provincial recovery.[emphasis added]***

Reference (c) suggests that initial OM&A costs in relation to the implementation of the GEA plan have been incurred, highlighting that :

In addition to increasing the workload of the pre-existing Customer Engineering team, Enersource has also added the following resources:

- 2 co-op intern Engineering students [...]
- A contracted independent Professional Engineer Field Inspector [...]
- A contracted Services Engineering firm [...]

Enersource is currently supporting the FIT Program with its existing staff compliment and the additional resources as outlined above. It has incorporated the associated costs during the course of annual budgeting.

OM&A costs associated with the implementation of the GEA plan are generally not reflected in Enersource's current plan. At reference (d):

Enersource will continue to connect generation projects as is required under the DSC. In order to achieve this, Enersource will require continued expenditures in the areas previously identified in section 3.4. This includes the Customer Engineering team as well as the additional resources such the two co-op students, Field Construction Inspector and Service Engineering company. The forecasted costs associated with this are shown in the table below.

Reference (e) points to the various accounting instruments twinned with the GEA Plan.

Reference (f) outlines the methodology for deriving direct benefits.

a) Please explain why costs referred to at reference (d) are not taken into account to derive direct benefits accruing to Enersource's ratepayers.

b) Please indicate whether capital expenses at table 6 of reference (d) would normally generate associated OM&A.

c) Based on the above, please reconcile the statement at reference (a) with the evidence at references (c) and (d).

d) Keeping in perspective reference (e) please explain why Enersource is choosing not to utilize the various accounting instruments at its disposal.

e) Enersource's GEA plan does not indicate how the distributor will recover costs strictly associated with the implementation of the plan. Please explain why Enersource is choosing not to follow the methodology outlined in the *Framework* at reference (f) given that it is a non-discretionary step where it is applicable.

f) If the noted requirement in Question e above is applicable, please include a direct benefits calculation arising from REI and expansion work that are primarily generated by the connection of renewable generation.

g) If the answer to Question f above is affirmative, please confirm that Enersource would be recording the costs as described on pages 22 and 23 of reference (g).

Response:

a) Enersource advises that the reference (d) above should be page 13 and not page 11, of Exhibit 2 Tab 2 Schedule 3 Appendix 1.

From the June 10, 2010 EB-2009-0349 Report of the Board "Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09" Enersource is mindful of the Board's approach to strike "a reasonable balance between administrative burden and incremental precision". Hence, its application seeks to minimize the administrative burden required by the Board and the parties to this proceeding in their consideration of what are nominal amounts being proposed in the GEA Basic Plan.

The EB-2009-0397 "Filing Requirements Distribution System Plans – Filing under Deemed Conditions of Licence", revised May 17, 2012, stated that a standardized approach is to be applied": "Currently, that approach calls for the use of the direct benefits allocation approved by the Board in the EB-2009-0096 proceeding pertaining to Hydro One Networks Inc., as follows: for expansions, 17% of the cost constitutes the direct benefits, and for REIs the direct benefits percentage is 6% of the costs."

Due to the fact that Enersource's proposed GEA Plan budget for the Test Year is relatively small at $183, and 6% of that amount is only $11, (for 2014 ICR those amounts are $219 and $13, respectively) Enersource did not believe that this warranted seeking any allocation to the provincial ratepayers.

b) Enersource has determined that any OM&A costs related to the implementation of the GEA plan would be immaterial and any incremental costs that would be incurred have not been included in OM&A.

c) Up to this point Enersource has been able to manage the incremental amounts of capital and OM&A related to RESs within its existing budgets. Please also refer to the response to a) above.

d) Enersource is aware that the Board has created capital and OM&A deferral accounts for renewable generation connection. However, Enersource has been able to fund all renewable generation connections since the inception of the GEA within base rates. Enersource's proposal to include a nominal capital amount in base rates for 2013 and 2014 reflects the immateriality of the expected renewable generation activity.

e) As described above the costs are immaterial and as such any direct benefits (calculated at 6% of these costs) would also be immaterial.

f) Not applicable, please refer to response g) above

g) Not applicable, please refer to response g) above.

Enersource requests to remove the total forecasted stranded meter net book value as of December 31, 2012, totalling $7,640, from rate base and to recover this amount through separate rate riders for the applicable customer classes. Enersource proposes the recovery period to be twelve months, effective January 1, 2013. Table 3 shows the proposed stranded meter rate rider by customer class.

Table 3: Stranded Meter Rate Rider by Customer Class

	Residential	GS < 50 kW	GS > 50 kW	Total
Smart Meters Forecasted Installed at May 1, 2012	167,525	17,627	1,410	186,562
Smart Meters Installed as a Percentage of Total	89.8%	9.4%	0.8%	100.0%
Stranded Meters Balance to be Recovered ($000s)	$ 6,860	$ 722	$ 58	$ 7,640
Number of Customers - 2013 Forecast	176,865	17,703	3,950	198,518
Rate Rider ($ per Customer/month)	**$ 3.23**	**$ 3.40**	**$ 1.22**	

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #67

Board Staff

10. Smart Meters

Issue: 10.1 - Is the proposed treatment of stranded meter costs appropriate?

Reference: E9/T2/S2 – Stranded Meters

A copy of Table 3 from Exhibit 9/Tab 2/Schedule 2 is shown below:

	Residential	GS < 50 kW	GS > 50 kW	Total
Smart Meters Forecasted/Installed at May 1, 2012	167,525	17,627	1,410	186,562
Smart Meters Installed as a Percentage of Total	89.80%	9.40%	0.80%	100.00%
Stranded Meters Balance to be Recovered ($000s)	6860	722	58	7640
Number of Customers - 2013 Forecast	176,865	17703	3950	198,518
Rate Rider ($ per Customer/month)	$3.23	$3.40	$1.22	

Enersource is proposing to recover the remaining net book value of stranded meters through class-specific stranded meter rate riders. For an allocator of the stranded meter costs, Enersource is using the number of smart meters installed in each class, as a percentage of total smart meters installed.

Table 4 of Exhibit 9/Tab 2/Schedule 1 shows that Residential Smart Meters capital costs are about $160/meter, while those for GS < 50 kW customers and for GS > 50 kW customers average about $500/meter and $540/meter, respectively. Board staff acknowledges that these include installation costs as well as the costs of the meters.

a) For the stranded conventional meters, please explain whether the cost per meter differs between Residential, GS < 50 kW and GS > 50 kW customer classes. This may be due, in part to the specifications and manufacture of meters (e.g., single-phase versus polyphase meters, maximum demand rating, etc.).
b) What is Enersource's rationale for using the number of smart meters installed as the allocator for stranded meter costs?
c) Please confirm whether the value of stranded meters by customer class is available, or a suitable proxy from, for example, Enersource's prior cost allocation studies.

d) If there is a suitable direct or proxy allocator of the value of stranded meters by customer class, please provide an updated Table 3 in working Microsoft Excel format.

Response:

a) The cost per stranded conventional meter would differ between Residential, GS < 50 kW and GS > 50 kW customer classes based on the type/specifications of the meter required for that particular customer class.

b) Enersource used the number of smart meters installed as a suitable allocator for stranded meter costs as the net book value of stranded meters by customer class is not available. Stranded meters for all customer classes were recorded together as pooled assets and not segregated by customer classes.

c) Refer to the response to part b) above.

d) Enersource believes that the number of smart meters installed is a suitable allocator for stranded meter costs given the lack of information surrounding net book value by customer class.

Undertaking No. JT1.1

To provide tab I7.1 of 2006 Cost Allocation informational filing. P. 19

Response:

Two cost allocation model runs, resulting from EB-2006-0247, were provided in Enersource's 2008 cost of service proceeding. Attachment 1 is Tab I7.1 of Run 1 of the CA Model. Attachment 2 is Tab I7.1 of Run 2.

See also Exhibit 7 Tab 1 Schedule 1.

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2006 Cost Allocation Information Filing
Enersource Hydro Mississauga
EB-2005-0360 EB-2006-0247
January 15, 2007
Sheet I7.1 Meter Capital Worksheet - First Run

		Residential			Small Commercial			GS < 50kW			GS 50 - 499kW		
		1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			33.40%			0%			32%			30%
	Cost Relative to Residential Average Cost			1.00			1.46			9.27			35.96
	Total	154805	8253960	53.31843287	226	17625	77.98672566	15848	7835165	494.3945508	3906	7489810	1917.514081
Meter Types	**Cost per Meter (Installed)**												
Single Phase 200 Amp - Urban	50	152,586	7629300		195	9750		1482	74100			0	
Single Phase 200 Amp - Rural	150		0			0			0			0	
Central Meter	250		0			0			0			0	
Network Meter (Costs to be updated)	225	1,854	417150		19	4275		169	38025			0	
Three-phase - No demand	210	21	4410		10	2100		9844	2057240		1	210	
Smart Meters	300		0			0			0			0	
Demand without IT (usually three-phase)	500	1	500		1	500		1,875	937500		594	297000	
Demand with IT	2,100		0			0		1,904	3998400		1727	3626700	
Demand with IT and Interval Capability - Secondary or Primary	2,300		0			0		137	315100		1531	3521300	
Demand with IT and Interval Capability - Primary	10,000		0			0			0			0	
Demand with IT and Interval Capability - Special (WMP)	40,000		0			0			0			0	
LDC Specific - single Phase w/IT	400	234	93600			0		143	57200		18	7200	
- 3 Phase w/IT No Demand	1200		0			0		42	50400			0	
- Single phase w/Dem, w/IT	1000	109	109000		1	1000		139	139000		29	29000	
- 3 Phase noIT w/Dem+Mass Memory	1400		0			0		113	158200		6	8400	

GS 500 - 4999kW			Large User > 5MW			Street Light			TOTAL		
1	2	3	1	2	3	1	2	3	1	2	3
Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
		4%			0%			0%			100%
		43.14			43.14			-			2.64
463	1064900	2300	22	50600	2300	0	0	-	175270	24712060	140.9942375
	0			0			0		154.263	7713150	
	0			0			0		0	0	
	0			0			0		0	0	
	0			0			0		2.042	459450	
	0			0			0		9.876	2073960	
	0			0			0		0	0	
	0			0			0		2.471	1235500	
	0			0			0		3.631	7625100	
463	1064900		22	50600			0		2.153	4951900	
	0			0			0		0	0	
	0			0			0		0	0	
	0			0			0		395	158000	
	0			0			0		42	50400	
	0			0			0		278	278000	
	0		0	0			0		119	166600	

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2006 COST ALLOCATION FILING
Enersource Hydro Mississauga
EB-2005-0360 EB2006-0247
January 15, 2007
Sheet 17.1 Meter Capital Worksheet - Second Run

#

Meter Types	Cost per Meter (Installed)	Residential 1 Number of Meters	Residential 2 Weighted Metering Costs	Residential 3 Weighted Average Costs	Small Commercial 1 Number of Meters	Small Commercial 2 Weighted Metering Costs	Small Commercial 3 Weighted Average Costs
Allocation Percentage Weighted Factor				33.40%			0%
Cost Relative to Residential Average Cost				1.00			-
Total		154805	8253960	53.3184328/	0	0	-
Single Phase 200 Amp - Urban	50	152,586	7629300			0	
Single Phase 200 Amp - Rural	150		0			0	
Central Meter	250		0			0	
Network Meter (Costs to be updated)	225	1,854	417150			0	
Three-phase - No demand	210	21	4410			0	
Smart Meters	300		0			0	
Demand without IT (usually three-phase)	500	1	500			0	
Demand with IT	2,100		0			0	
Demand with IT and Interval Capability - Secondary or Primary	2,300		0			0	
Demand with IT and Interval Capability - Primary	10,000		0			0	
Demand with IT and Interval Capability - Special (WMP)	40,000		0			0	
LDC Specific - single Phase w/IT	400	234	93600			0	
- 3 Phase w/IT No Demand	1200		0			0	
- Single phase w/Dem. w/IT	1000	109	109000			0	
- 3 Phase noIT w/Dem+Mass Memory	1400		0			0	

Meter Types	GS < 50kW 1 Number of Meters	GS < 50kW 2 Weighted Metering Costs	GS < 50kW 3 Weighted Average Costs	GS 50 - 499kW 1 Number of Meters	GS 50 - 499kW 2 Weighted Metering Costs	GS 50 - 499kW 3 Weighted Average Costs	GS 500 - 4999kW 1 Number of Meters	GS 500 - 4999kW 2 Weighted Metering Costs	GS 500 - 4999kW 3 Weighted Average Costs	L 1 Number of Meters
Allocation Percentage Weighted Factor			32%			30%			4%	
Cost Relative to Residential Average Cost			9.16			35.96			43.14	
Total	16974	7852790	488.5396761	3906	7469810	1917.514081	461	1060300	2300	22
Single Phase 200 Amp - Urban	1677	83850			0			0		
Single Phase 200 Amp - Rural		0			0			0		
Central Meter		0			0			0		
Network Meter (Costs to be updated)	188	42300			0			0		
Three-phase - No demand	9854	2069340		1	210			0		
Smart Meters		0			0			0		
Demand without IT (usually three-phase)	1,876	938000		594	297000			0		
Demand with IT	1,904	3998400		1727	3626700			0		
Demand with IT and Interval Capability - Secondary or Primary	137	315100		1531	3521300		461	1060300		22
Demand with IT and Interval Capability - Primary		0			0			0		
Demand with IT and Interval Capability - Special (WMP)		0			0			0		
LDC Specific - single Phase w/IT	143	57200		18	7200			0		
- 3 Phase w/IT No Demand	42	50400			0			0		
- Single phase w/Dem. w/IT	140	140000		29	29000			0		
- 3 Phase noIT w/Dem+Mass Memory	113	158200		6	8400			0		0

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Undertaking No. JT1.2

To determine, if the response to the previous undertaking is that there is data in previous cost allocation studies that go to demonstrate the difference between the meter classes costs, would Enersource use that data in order to recalculate the rider, the stranded meter rider, and if not then provide a reason why that would not be a good methodology to use. P. 23

Response:

Enersource's proposal to allocate the stranded meter disposition rate rider to the applicable customer classes based on the number of smart meters installed is consistent with the allocation methodology approved by the Board in Guelph Hydro Electric System Inc.'s 2012 cost of service application (EB-2011-0123).

Based on the information provided in JT 1.1 and assuming Run 2 is used as the basis of the allocation, the stranded meter rate rider would be as follows:

Table 1: Stranded Meter Disposition Rate Rider Based on Cost Allocation Model Run 2

	Residential	GS < 50 kW	GS > 50 kW	Total
Smart Meters Forecasted Installed at May 1, 2012	167,525	17,627	1,410	186,562
Tab I7.1 Meter Weighting (2006 CA Model Tab I7.1 Run 2)	1	9.16	35.96	
Calculation	167,525	161,463	50,704	379,692
Weighting	44.1%	42.5%	13.4%	100.0%
Stranded Meters Balance to be Recovered ($000s)	$ 3,369	$ 3,247	$ 1,024	$ 7,640
Number of Customers - 2013 Forecast	176,865	17,703	3,950	198,518
Rate Rider ($ per Customer/month)	**$ 1.59**	**$ 15.28**	**$ 21.60**	