Rate Base - Overview

This exhibit provides Enersource's distribution rate base forecast for the 2013 Test Year. It also provides an explanation of variances between the 2008 Board-approved rate base and each of these years: 2009 to 2011actuals, 2012 Bridge Year and the 2013 Test Year.

As discussed at Exhibit 1 Tab 2 Schedule 1, Enersource is seeking approval in this Application, based on a forward test year, for 2013 electricity distribution rates ("EDR") effective January 1, 2013 ("Test Year"), and for incremental capital and return ("ICR") for 2014 EDR, effective January 1, 2014 ("ICR Year"). To support this proposal, Enersource has also included the rate base forecast for the 2014 ICR Year in this exhibit. The ICR Year rate base includes the forecast of net capital assets, the related depreciation, and the payments-in-lieu-of-taxes ("PILS") impact.

In accordance with the Board's Filing Requirements, the rate base used to determine the Test Year revenue requirement includes the average of the opening and closing balances for net capital assets plus a working capital allowance. Net capital assets are gross assets in service minus accumulated depreciation and contributed capital from third parties.

Capital assets include property, plant and equipment and intangible assets. These have been referred to as "capital assets" throughout this evidence.

Based on the Board Report[1] at the first rebasing in Modified International

[1] OEB proceeding EB-2008-0408 resulted in the issuance of the *Report of the Board, Transition to IFRS*, on July 28, 2009, subsequently amended November 8, 2010, and March 15, 2011, and then appended by an addendum, dated June 13, 2011, (collectively, the "Board Report").

Financial Reporting Standards ("MIFRS"), a distributor's rate base will include an additional component relating to the transition to MIFRS. This is referred to as "IFRS-CGAAP Transitional Rate Base Adjustment" throughout this document.

Table 1 shows the 2008 Board-approved distribution rate base and the rate base forecast for the 2013 Test Year and the 2014 ICR Year. Table 2 shows the continuity of rate base from 2008 to 2014.

Table 1: 2008 Board-Approved Rate Base and 2013/2014 Rate Base ($000s)

Description	2008 Board Approved	2013 Test Year MIFRS	2014 ICR Year MIFRS
Asset Values at Cost	$ 794,248	$ 582,788	$ 624,629
Construction Work in Progress	$ (5,182)	$ (4,519)	$ (4,519)
Accumulated Depreciation	$ (378,429)	$ (58,621)	$ (83,966)
Net Assets	**$ 410,637**	**$ 519,647**	**$ 536,143**
Working Capital Allowance	$ 85,925	$ 107,241	$ 107,241
Rate Base	**$ 496,562**	**$ 626,888**	**$ 643,384**
IFRS-CGAAP Transitional Rate Base Adjustm	$ -	$ (12,821)	$ -
Adjusted Rate Base	**$ 496,562**	**$ 614,067**	**$ 643,384**

Table 2: Continuity of Calculated Rate Base, 2008-2014 ($000s)

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual MIFRS	2012 Bridge Year MIFRS	2013 Test Year MIFRS	2014 ICR Year MIFRS
Asset Values at Cost	$ 794,248	$ 785,012	$ 826,146	$ 868,888	$ 695,580	$ 531,521	$ 582,788	$ 624,629
Construction Work in Progress	$ (5,182)	$ (12,211)	$ (10,043)	$ (6,624)	$ (6,510)	$ (4,570)	$ (4,519)	$ (4,519)
Accumulated Depreciation	$ (378,429)	$ (363,426)	$ (386,709)	$ (413,366)	$ (225,286)	$ (34,289)	$ (58,621)	$ (83,966)
Net Assets in Rate Base	**$ 410,637**	**$ 409,375**	**$ 429,395**	**$ 448,899**	**$ 463,784**	**$ 492,663**	**$ 519,647**	**$ 536,143**
Working Capital Allowance	$ 85,925	$ 81,578	$ 82,606	$ 95,874	$ 97,609	$ 101,256	$ 107,241	$ 107,241
Rate Base	**$ 496,562**	**$ 490,953**	**$ 512,001**	**$ 544,772**	**$ 561,393**	**$ 593,918**	**$ 626,888**	**$ 643,384**
IFRS-CGAAP Transitional Rate base adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ (12,821)	$ -
Adjusted Rate Base	**$ 496,562**	**$ 490,953**	**$ 512,001**	**$ 544,772**	**$ 561,393**	**$ 593,918**	**$ 614,067**	**$ 643,384**

The 2013 Test Year adjusted rate base forecast of $614,067 is $117,505 higher than the 2008 Board-approved rate base due to:

- Increase in average net capital assets of $109,010;
- Decrease in rate base due to the IFRS-CGAAP Transitional Rate Base Adjustment of $12,821; and
- Increase in the working capital allowance of $21,317.

The major drivers of the increase in net capital assets are:

- Inclusion of smart meter expenditures in rate base;
- Purchase of an Administration Office and retrofit of the Operations Centre;
- An increase of distribution and substations net assets;
- Continuous investments in information systems and other general plant assets;

- Transition to IFRS (change of useful lives, non-capitalization of overhead costs, early de-recognition of assets); and
- A decrease resulting from the transfer of stranded meters to regulatory asset 1555 account. See Exhibit 9 Tab 2 Schedule 2 for further details.

The IFRS-CGAAP Transitional Rate Base Adjustment of $12,821 for the 2013 Test Year represents the difference in rate base arising by the transition from CGAAP to MIFRS. This amount, plus the return on capital and PILs impact, is proposed to be refunded to customers over a one-year period commencing January 1, 2013 through a rate rider as detailed in Exhibit 9 Tab 1 Schedule 1. This will serve to align MIFRS capital assets to Enersource's capital assets presented in the IFRS external financial statements.

The working capital allowance increased by $21,317 over the five-year period mainly due to the inclusion of Global Adjustment in the cost of power forecast. This is discussed further at Exhibit 2 Tab 1 Schedule 4.

The 2014 ICR Year rate base forecast of $643,384 is $29,317 higher than 2013 Test Year forecast. This is due to the $16,496 increase in net capital assets and the prior year IFRS-CGAAP Transitional Rate Base Adjustment of $12,821.

The working capital allowance requested for the 2014 ICR Year is the same as the 2013 Test Year due to the fact that none of the factors influencing this calculation are considered for the 2014 ICR Year. Please refer to Exhibit 1 Tab 2 Schedule 1 which addresses the 2014 proposal in more detail.

In accordance with the Board's Filing Requirements, Appendix 2-B "Fixed Asset Continuity Schedule" is provided at Exhibit 2 Tab 1 Schedule 2. Also, the Working Capital Allowance is discussed at Exhibit 2 Tab 1 Schedule 4.

Enersource's materiality threshold used for the Test Year and the ICR Year is $645, per Exhibit 1 Tab 4 Schedule 1.

Capital Assets

Enersource's capital assets are recorded and recognized at cost, and include direct labour and benefits, materials, fleet and contractor costs, which are incurred during the development, implementation, or construction phase of the asset.

Certain capital assets may be funded or paid by a customer or third party developer through capital contributions. Under IFRS, the capital contributions that are recognized as deferred revenue have been reclassified as a reduction to rate base under MIFRS. Enersource's capital assets that are included in rate base are also net of accumulated depreciation based on pre-determined rates, which vary by asset class or type.

Up to 2011, under CGAAP, Enersource had capitalized interest based on the OEB's prescribed allowance for funds used during construction ("AFUDC"). Starting in 2011, under IFRS, Enersource began to use its actual borrowing costs as the basis for determining the amount of interest to be capitalized for qualifying assets and has included this amount in capital asset additions for 2011-2014.

The continuity of capital assets cost, accumulated depreciation, and net book value is shown in Tables 3 to 5 below.

Table 3: Continuity of Capital Assets Cost, 2008-2014 ($000s)

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual MIFRS	2012 Bridge MIFRS	2013 Test MIFRS	2014 Test MIFRS
Opening Balance	$ 756,357	$ 766,280	$ 803,744	$ 848,548	$ 464,327	$ 501,932	$ 561,110	$ 604,466
Capital Additions	$ 47,517	$ 51,503	$ 59,342	$ 53,028	$ 42,563	$ 64,486	$ 46,446	$ 45,624
Retirements/ Disposals	$ (9,625)	$ (14,039)	$ (14,537)	$ (12,348)	$ (4,958)	$ (5,308)	$ (3,091)	$ (5,297)
Closing Balance	$ 794,248	$ 803,744	$ 848,548	$ 889,228	$ 501,932	$ 561,110	$ 604,466	$ 644,792
Average Balance	**$ 794,248**	**$ 785,012**	**$ 826,146**	**$ 868,888**	**$ 695,580**	**$ 531,521**	**$ 582,788**	**$ 624,629**

Table 4: Continuity of Capital Assets Accumulated Depreciation, 2008 – 2014 ($000s)

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual MIFRS	2012 Bridge MIFRS	2013 Test MIFRS	2014 Test MIFRS
Opening Balance	$ (363,457)	$ (352,393)	$ (374,460)	$ (398,957)	$ -	$ (22,797)	$ (45,780)	$ (71,462)
Capital Additions	$ (24,597)	$ (33,847)	$ (35,335)	$ (38,114)	$ (23,589)	$ (25,068)	$ (26,791)	$ (28,264)
Retirements/ Disposals	$ 9,625	$ 11,780	$ 10,838	$ 9,297	$ 792	$ 2,085	$ 1,109	$ 3,256
Closing Balance	$ (378,429)	$ (374,460)	$ (398,957)	$ (427,774)	$ (22,797)	$ (45,780)	$ (71,462)	$ (96,470)
Average Balance	**$ (378,429)**	**$ (363,426)**	**$ (386,709)**	**$ (413,366)**	**$ (225,286)**	**$ (34,289)**	**$ (58,621)**	**$ (83,966)**

Table 5: Continuity of Net Capital Assets, 2008-2014 ($000s)

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual MIFRS	2012 Bridge MIFRS	2013 Test MIFRS	2014 Test MIFRS
Closing Net Assets including CIP	$ 415,819	$ 429,284	$ 449,591	$ 461,454	$ 479,135	$ 515,330	$ 533,003	$ 548,322
Closing Average Net Assets	$ 415,819	$ 421,585	$ 439,438	$ 455,523	$ 470,295	$ 497,232	$ 524,166	$ 540,663
Less Average CIP	$ (5,182)	$ (12,211)	$ (10,043)	$ (6,624)	$ (6,510)	$ (4,570)	$ (4,519)	$ (4,519)
Net Assets in Rate Base	**$ 410,637**	**$ 409,374**	**$ 429,395**	**$ 448,899**	**$ 463,784**	**$ 492,663**	**$ 519,647**	**$ 536,143**

The variances in closing net assets including construction-in-progress ("CIP") balances are explained below:

2008 Board-Approved Net Capital Assets to 2011 Actual Net Capital Assets

The cumulative net assets for 2011 (line 1 on Table 5) increased by $63,315 compared to 2008 Board-approved net assets, or an average of 5.08% each year, as a result of:

- $26,794 net expenditures in smart metering;
- $15,733 increase in overhead and underground distribution system investments including $1,239 for the PCB transformer replacements;
- $4,693 payment to Hydro One to build the Churchill Meadows Transformer Station;
- $6,814 increase in distribution substation equipment upgrades and rebuilds;
- $6,514 continuous investments in information systems and other distribution system assets including $2,859 for Customer Care and Billing ("CC&B") System and $2,003 for JD Edwards ("JDE") upgrade;
- $6,444 transition to MIFRS impact for 2011 (change of useful lives, non-capitalization of overhead costs, early de-recognition of assets);
- $1,824 for facilities, equipment and substation facilities improvements;
- $2,059 for metering projects primarily wholesale metering upgrades and individual metered suites retrofits; and

- Offsetting the increase in the net assets is the transfer of $7,560 stranded meters to regulatory asset 1555 account.

2012 Forecast Net Capital Assets vs. 2011 Actual Net Capital Assets

Total net assets for 2012 are expected to increase by $36,195, or 7.55%, over the actual amount for 2011.

The major drivers of the net assets increase in 2012 are:

- $20,000 for the purchase and retrofit of a new administration office;
- $2,023 for improvements to the operations and substation facilities;
- $9,239 increase in overhead and underground distribution system investments;
- $1,846 increase in substation assets primarily due to the new Erin Mills Substation and continuous upgrades and refurbishments of existing substation equipment;
- $1,593 continuous investments in information systems;
- $2,579 for investments in wholesale meter upgrades;
- $1,424 for other metering projects, primarily individual metered suites retrofits; and
- Offsetting the increase in the net assets is the transfer of stranded meters to regulatory asset 1555 account of $1,300 and the depreciation of smart meters of $1,209.

2013 Forecast Net Capital Assets vs. 2012 Forecast Net Capital Assets

Total net assets for the 2013 Test Year are expected to increase by $17,673, or 3.43%, over the forecasted amount for 2012.

The major drivers of the net assets increase in 2013 are:

- $6,722 for improvements to the operations centre and substation facilities;
- $9,687 increase in overhead and underground distribution system investments;
- Purchase of a $2,000 easement required for Churchill Meadows TS Egress Feeders project;
- $1,162 increase in substation assets primarily due to the new Erin Mills Substation and continuous upgrades and refurbishments of other substation equipment;
- $828 for metering projects, primarily wholesale metering upgrades and individual metered suites retrofits; and
- Offsetting the increase in the net assets is the depreciation of smart meters of $2,726.

2014 Forecast Net Capital Assets vs. 2013 Forecast Net Capital Assets

The net book value of capital assets for the 2014 ICR Year is expected to increase by $15,319, or 2.87%, over the forecasted amount for 2013.

The major drivers of the net assets increase in 2014 are:

- $1,301 for continuous upgrades and refurbishments of substation equipment;
- $11,527 increase in overhead and underground distribution system investments;
- $3,938 for facilities, equipment and substation facilities improvements;
- $1,224 increase in metering, mainly due to investments in individual metered suites retrofits; and
- Offsetting the increase in the net assets is mainly the depreciation of smart meters of $2,671.

Working Capital Allowance

The Working Capital Allowance for 2013 is $107,241, as discussed at Exhibit 2 Tab 1 Schedule 4. A continuity of the working capital from 2008 to 2013 is provided at Table 1 of that exhibit.

IFRS Impact

Under IFRS[2], an entity must present and record separately from property, plant, and equipment ("PP&E") those assets that are within the scope of International Accounting Standard 38 Intangible Assets ("IAS 38").

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[2]On March 31, 2012, an announcement by Canada's Accounting Standards Board ("AcSB"), who were meeting on March 20-21, noted the following:

"The AcSB decided to extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate regulated activities by one year to January 1, 2013 in light of the recent discussions of the IASB's future agenda."

Enersource understands that the basis for the AcSB's extended deferral relates to the continuing deliberations by the International Accounting Standards Board regarding its agenda project on rate regulatory activities and the potential

The Board Report[3] states the following:

"IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E. Utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining the revenue requirement. This reclassification is also necessary to preserve continuity of the rate base."

Based on the above, for MIFRS, Enersource has included intangible assets as PP&E for rate setting purposes.

The major differences between IFRS and CGAAP with respect to the accounting for PP&E and intangible assets are outlined below.

Opening Balances

The International Accounting Standards Board ("IASB") amended "*IFRS 1 – First-time adoption of IFRS"* in May, 2010 to allow rate-regulated entities to use the previous accounting net book value as the IFRS cost on the date of transition to IFRS. This is referred to as the deemed cost exemption.

Enersource has elected to use the deemed cost election under IFRS 1 for opening balance sheet values for its capital assets.

Based on paragraph D8B of IFRS 1, entities with operations subject to rate regulations may hold items of PP&E or intangible assets where the carrying

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development of interim guidance prior to pre-changeover standards. However, Enersource had already proceeded with its transition to MIFRS, effective January 1, 2012, and has elected to maintain its adoption of IFRS.

[3] OEB proceeding EB-2008-0408 resulted in the issuance of the *Report of the Board, Transition to IFRS*, on July 28, 2009, subsequently amended November 8, 2010, and March 15, 2011, and then appended by an addendum, dated June 13, 2011, (collectively, the "Board Report").

amount of such items might include amounts that were determined under previous GAAP but do not qualify for capitalization in accordance with IFRS. In this case, a first-time adopter may elect to use the previous GAAP carrying amount of such an item at the date of transition to IFRS as deemed cost.

For the purposes of paragraph D8B, operations are subject to rate regulation if they provide goods or services to customers at prices (i.e., rates) established by an authorized body empowered to establish rates that bind the customers, and that are designed to recover the specific costs the entity incurs in providing the regulated goods or services, and to earn a specified return. Based on the definition above, Enersource qualifies for this exemption.

Under this exemption the deemed cost at the date of transition becomes the new IFRS cost basis. Therefore, on January 1, 2011, the opening accumulated depreciation is $nil under IFRS and the opening cost equates to the closing CGAAP net book value ("NBV") as shown in Table 6 below.

Table 6: Reconciliation of MIFRS Opening 2011 Net Book Value ($000s)

	CGAAP Ending 2010			IFRS Opening 2011			MIFRS Opening 2011	
Description	**Cost**	**Accumulated Depreciation**	**NBV**	**Cost**	**Accumulated Depreciation**	**NBV**	**Transfer from Reg Asset (1555)**	**NBV adjusted**
Land and Buildings	$ 22,705	$ (6,147)	$ 16,557	$ 16,557	$ -	$ 16,557		$ 16,557
TS Primary Above 50	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Distribution System	$ 79,857	$ (30,403)	$ 49,454	$ 49,454	$ -	$ 49,454		$ 49,454
Poles, Wires	$ 674,820	$ (315,716)	$ 359,104	$ 264,797	$ -	$ 264,797		$ 264,797
Line Transformers	$ 63,439	$ (44,627)	$ 18,812	$ 50,307	$ -	$ 50,307		$ 50,307
Services and Meters	$ 57,299	$ (24,027)	$ 33,272	$ 33,272	$ -	$ 33,272	$ 2,873	$ 36,145
General Plant	$ -	$ -	$ -	$ -	$ -	$ -		$ -
Equipment	$ 23,685	$ (13,229)	$ 10,456	$ 10,456	$ -	$ 10,456		$ 10,456
IT Assets	$ 23,698	$ (6,347)	$ 17,351	$ 17,351	$ -	$ 17,351		$ 17,351
Other Distribution Assets	$ 17,048	$ (8,303)	$ 8,746	$ 10,859	$ -	$ 10,859		$ 10,859
CIP	$ 8,400	$ -	$ 8,400	$ 8,400	$ -	$ 8,400		$ 8,400
Customer Contributions	$ (81,724)	$ 21,026	$ (60,699)	$ -	$ -	$ -		$ -
Closing Balance	**$ 889,228**	**$ (427,774)**	**$ 461,454**	**$ 461,454**	**$ -**	**$ 461,454**	**$ 2,873**	**$ 464,327**

The amount of $2,873, shown as a transfer from regulatory assets in Table 6, represents an adjustment to the MIFRS opening balance to reduce the amount recorded in regulatory assets (account 1555) based on Guideline G-2011-0001[4].

Stranded meters were kept in capital assets and were depreciating as part of net capital assets. The NBV was moved from PP&E each period to account 1555 via a contra account to PP&E, but the consequent depreciation related to this NBV was not transferred to the regulatory asset account.

In 2011, to comply with Guideline G-2011-0001, Enersource reduced the amount recorded in the stranded meters 1555 account and increased the net book value of its PP&E by $2,873. This amount represents the accumulated

[4] *Ontario Energy Board G-2011-0001 Guideline, Smart Meter Funding and Cost Recovery – Final Disposition*, dated December 15, 2011 ("Guideline G-2011-0001").

depreciation that was kept in PP&E and should have been moved to 1555 USofA account.

Table 7 below shows the details of MIFRS capital assets opening balances as of January 1, 2011.

Table 7: Reconciliation of CGAAP Cost Closing Balance to MIFRS Cost Opening Balance ($000s)

2011 IFRS Opening Cost Reconciliation

Description	2010 CGAAP Closing Balance	Accumulated Depreciation Adjustment	Capital Contribution Adjustment	Transfers	2011 MIFRS Opening Balance
Land and Buildings	$ 22,705	$ (6,147)			$ 16,557
TS Primary Above 50	$ -	$ -			$ -
Distribution System	$ 79,857	$ (30,403)			$ 49,454
Poles, Wires	$ 674,820	$ (315,716)	$ (58,692)	$ (35,616)	$ 264,797
Line Transformers	$ 63,439	$ (44,627)	$ (2,007)	$ 33,503	$ 50,307
Services and Meters	$ 57,299	$ (24,027)		$ 2,873	$ 36,145
General Plant	$ -	$ -			$ -
Equipment	$ 23,685	$ (13,229)			$ 10,456
IT Assets	$ 23,698	$ (6,347)			$ 17,351
Other Distribution Assets	$ 17,048	$ (8,303)		$ 2,113	$ 10,859
CIP	$ 8,400	$ -			$ 8,400
Customer Contributions	$ (81,724)		$ 81,724		$ -
Closing Balance	**$ 889,228**	**$ (448,800)**	**$ 21,026**	**$ 2,873**	**$ 464,327**

Accumulated Depreciation Adjustment column in Table 7 represents the adjustment done to reset the IFRS January 1, 2011 opening cost values to equal to the CGAAP closing NBV of December, 2010.

Capital contribution adjustment column in Table 7 represents the adjustment to net book value of distribution system assets. Accumulated customer contribution balance has been set to zero as at January 1, 2011 for IFRS, as the cumulative balance has been offset against the costs of related capital assets for which the contribution was received. Starting in 2011, customer

contributions will be recorded as deferred revenue for IFRS as explained below.

Transfers in Table 7 represent:

- The movements from poles and wires category to line transformers and other distribution assets represent the net book value allocation from overhead and distribution system category to line transformers and supervisory control equipment due to the adoption of IFRS; and

- The increase in services and meters of $2,873 represents opening balances adjustment to reduce the amounts recorded in regulatory assets (account 1555) based on Guideline G-2011-0001.

Table 8: Reconciliation of CGAAP Accumulated Depreciation Closing Balance to MIFRS Opening Balance ($000s)

Description	2010 CGAAP Closing Balance	Accumulated Depreciation Adjustment	Capital Contribution Adjustment	Transfer	2011 MIFRS Opening Balance
Land and Buildings	$ (6,147)	$ 6,147			$ -
TS Primary Above 50	$ -	$ -			$ -
Distribution System	$ (30,403)	$ 30,403			$ -
Poles, Wires	$ (315,716)	$ 315,716			$ -
Line Transformers	$ (44,627)	$ 44,627			$ -
Services and Meters	$ (24,027)	$ 24,027			$ -
General Plant	$ -	$ -			$ -
Equipment	$ (13,229)	$ 13,229			$ -
IT Assets	$ (6,347)	$ 6,347			$ -
Other Distribution Assets	$ (8,303)	$ 8,303			$ -
CIP	$ -	$ -			$ -
Customer Contributions	$ 21,026		$ (21,026)		$ -
Closing Balance	**$ (427,774)**	**$ 448,800**	**$ (21,026)**	**$ -**	**$ -**

As shown in Table 8 above, the accumulated depreciation has been set to zero as at January 1, 2011 for IFRS, as the cumulative balance as of December 31, 2010 has been offset against the costs, as illustrated and explained in Table 7 above..

Under IFRS, the ending net capital assets for 2011 and forecast 2012 will be different from those under CGAAP. These differences are shown in Tables 9 and 10 below and explained in detail in the following sections.

Table 9: 2011 Difference in Total Net Assets, MIFRS vs. CGAAP ($000s)

Description	2011 CGAAP
Asset Values at Cost	$ 904,872
Accumulated Depreciation	$ (432,181)
Total Net Assets CGAAP	**$ 472,691**
Change of useful Lives of assets	$ 10,734
Overhead capitalization	$ (2,525)
Early Derecognition of Assets	$ (1,859)
Reduction in Depreciation due to Burdens & Derecognition	$ 94
Total Net Assets MIFRS	**$ 479,135**
Total Net Assets Difference	**$ 6,444**

Table 10: 2012 Difference in Total Net Assets, MIFRS vs. CGAAP ($000s)

Description	2012 CGAAP
Asset Values at Cost	$ 964,685
Accumulated Depreciation	$ (462,177)
Total Net Assets	**$ 502,508**
2011 Net Difference	$ 6,444
2012 Change of useful Lives of assets	$ 11,030
2012 Overhead capitalization	$ (3,022)
2012 Early Derecognition of Assets	$ (1,924)
2012 Reduction in Depreciation due to Burdens & Derecognition	$ 292
Total Net Assets MIFRS	**$ 515,330**
Total Net Assets Difference	**$ 12,821**

New Componentization Structure/Change of Useful Lives

IFRS requires each part of an item of PP&E and intangible asset with a cost that is significant in relation to the total cost of the item and for which different depreciation methods or rates are appropriate, to be depreciated separately.

IAS 16.43 requires an entity to depreciate separately each part of an item of PP&E that has a cost that is significant in relation to the total cost of the item. This requirement means that the total cost of a PP&E item should either be allocated to each significant part (where acquired as a whole) or (if constructed) the cost should be capitalized according to the significant part.

Under CGAAP, Enersource generally followed the guidance as specified in the Board's Accounting Procedures Handbook.[5] Under CGAAP, Enersource recorded PP&E as pooled assets based on major accounting classes in the year of capitalization, and generally consisted of high level asset groupings such as overhead distribution, underground distribution, as well as distinct components such as buildings and rolling stock.

IFRS currently does not have a standard for rate-regulated activities and does not allow for the use of externally mandated useful lives.

Prior to the adoption of IFRS, Enersource and four other distributors engaged Kinectrics Inc., to undertake a study, entitled *Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets*, dated December 10, 2009. For reference purposes, the short

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[5] Enersource has followed the Board's *Accounting Procedures Handbook for Electric Distribution Utilities*, revised July 31, 2007. On March 28, 2012, the Board released the *Accounting Procedures Handbook for Electricity Distributors* ("new APH"). Enersource is reviewing the new APH to confirm no changes to the Application are required.

name is "Enersource's Useful Lives Study" and is filed at Exhibit 2 Tab 1 Schedule 2 Appendix 1.

The OEB subsequently retained Kinectrics Inc. to prepare a similar study, entitled *Asset Depreciation Study for the Ontario Energy Board*, dated July 8, 2010, ("OEB Asset Depreciation Study") available on the OEB's website.[6] These two studies are generally consistent.

The Enersource's Useful Lives Study identified additional components or asset groups, and pinpointed several assets that had significant values and different typical useful lives such as poles, transformers, switchgears, underground cables, metering, etc. Informed by the Enersource's Useful Lives Study, Enersource applied its professional judgment to establish a new level of asset componentization under IFRS which is consistent with the requirements under IAS 16.9. Enersource determined that some of the assets identified were individually insignificant and would not be recognized as separate assets or components under IFRS. Enersource's asset management practices are to replace immaterial and insignificant components at the same time as the significant component, if it is more prudent and efficient to do so at the time of replacement.

Therefore, while there remains a degree of pooling of capital assets under IFRS, Enersource now has a more detailed level componentization than previously recognized under CGAAP. Due to their nature, buildings and

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[6] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0178/Kinetrics-418033-OEB%20Asset%20Amortization-%20Final%20Rep.pdf

rolling stock (fleet vehicles) will continue to be separately-identified assets and will not be pooled.

As an outcome of the OEB Asset Depreciation Study, distributors will remain responsible for the review and updates of their capital asset service lives for financial reporting and regulatory requirements. Enersource's new asset useful lives are shown in Table 11 below and are within the ranges specified in the OEB Asset Depreciation Study.

Table 11: Enersource's Asset Useful Lives

Asset Category	Enersource Useful Life (years)
Land	n/a
Easements	n/a
Building & Fixtures – Brick, Stone, Concrete & Steel	60
Building & Fixtures – Other Construction	20
General Equipment	10
Distribution station equipment	40
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The revised componentization structure under IFRS resulted in the extension of the useful lives of the majority of Enersource's capital assets. The extended useful lives reduced depreciation expense recorded under IFRS as compared to CGAAP, for 2011 and 2012, as shown in Table 12 below.

Table 12: IFRS Componentization Impacts in 2011 and 2012 ($000s)

	2011	2012
Componentization/Useful Lives	$ 10,734	$ 11,030

Change of Capitalization Policy

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP, are not allowed under IFRS.

Based on the Board Report, the Board requires utilities to adhere to IFRS capitalization accounting requirements for rate-making and regulatory reporting purposes after the date of adoption of IFRS, and that a utility is required to file a copy of its capitalization policy, as part of its first cost of service rate filing after adopting IFRS.

In light of all the above, Enersource, in conjunction with its IFRS advisor and auditor, performed a thorough analysis of all costs that were being capitalized under CGAAP in order to determine if they were eligible for capitalization under IFRS. These costs included materials, labour, benefits, truck, sub-contractor, overhead, customer contributions, and borrowing costs. The analysis conducted by Enersource has been summarized in the following sections of this evidence.

Material Cost

These costs include stocked items taken from warehouse and issued out to each project as well as direct materials which are purchased and delivered to

the job site directly. These costs represent the purchase price and initial delivery/handling costs of the materials.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management, hence there will be no impact on the amount of material costs being capitalized for IFRS.

Material Burden

Under CGAAP a fixed percentage or a fixed fee is allocated to capital projects which represents the cost associated with acquiring, handling, and storing of materials. The material burden also included the labour costs and the associated employee benefits of staff working in Stores Operations and the Procurement department.

Since IFRS only allows directly attributable costs to be capitalized, Enersource has concluded that material burden will not be capitalized under IFRS as it is impractical for Enersource to determine whether these costs are directly attributable to an individual project and even more difficult to attribute them to each inventory item being issued. Therefore, these costs are determined to be general overhead and will be recognized as an expense in the period incurred.

Labour Costs

The labour costs that are capitalized to PP&E comprise of engineering, design, linemen, construction, supervision, and managerial time working directly on the item of PP&E. These costs are allocated to PP&E via timesheets which record the nature of the actions and activities being

undertaken and time spent on each task by each type of employee. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. Therefore, there will be no impact on the amount of labour costs being capitalized under IFRS relating to this cost category.

Benefit Costs

Employee benefit costs represent the costs associated with employee pensions, vacations, sick leave, etc. For each hour of regular time recorded, via a timesheet, directly to a capital project, Enersource adds a benefit rate per hour that allocates the estimated annual costs per employee type.

Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. Enersource has determined there will be no impact on the amount of employee benefit costs being capitalized under IFRS.

Labour Burden

Under CGAAP, a fixed percentage of overhead and administration costs, referred to as “labour burden”, is allocated to direct labour costs, and forms part of the cost of an asset. These costs include the labour costs, related benefits and other general administrative costs of the senior operations management and directors that cannot be attributed to a specific project.

Therefore, Enersource has concluded that labour burden will not be capitalized under IFRS and therefore these costs will be expensed in the period incurred.

Transportation and Fleet Costs

These costs include the costs associated with maintaining automobiles, trucks and equipment, trailers and other fleet equipment. Some of these costs include depreciation expense of the fleet vehicles, fuel costs, repairs, and parts, insurance and all other items of expense necessary to keep the rolling stock in service. These costs can also include the labour costs and the associated benefits of the staff directly involved in rolling stock maintenance (mechanics and other garage staff) as tracked via timesheets.

Each vehicle has an individual JDE work order and all the above costs related to the maintenance of that vehicle are accumulated under the work order, and therefore all the costs are directly attributable. A fleet rate is determined on an annual basis for each vehicle group by dividing the annual costs accumulated for each vehicle type by their annual usage. When a vehicle is used for a capital project, a fleet rate is charged based on the type of vehicle used multiplied by hourly usage of the vehicle. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. Enersource has determined there will be no impact on the amount of transportation costs being capitalized under IFRS.

Fleet Burden

Under CGAAP, a fixed percentage of fleet costs referred to as “truck burden” is allocated to transportation costs and forms part of the cost of the asset. These costs include general maintenance costs such as salaries and benefits of administration personnel and any other general maintenance activities not

directly attributed to each vehicle. Therefore, Enersource has concluded that truck burden will not be capitalized under IFRS.

Third Party Costs

Sub-contractor costs are incurred when Enersource engages a third party to perform services. Under both CGAAP and IFRS, these costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management. Enersource has determined there will be no impact on the amount of third party costs being capitalized under IFRS.

Discontinued Capitalization

Due to all the above, effective January 1, 2011, Enersource discontinued the capitalization of general overhead costs including labour burdens, general administration, material handling and fleet burdens.

This change resulted in a decrease of capital expenditures of $2,525 compared to CGAAP and the offsetting increase in OM&A for the same amount for 2011. The estimates for 2012 to 2014 are shown in Table 13 below.

Table 13: IFRS Overhead Capitalization 2011 to 2014 ($000s)

	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Overhead Capitalization	$ (2,525)	$ (3,022)	$ (2,774)	$ (3,026)

Early Derecognition of Assets

Under IFRS an asset should be derecognized when it is disposed or when no future economic benefits are expected from its use. Any gain or loss upon

early derecognition should be included in profit or loss when the item is derecognized.

The Board Report[7] states:

> *"Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the Board."*

Consistent with guidance in the Board Report, Enersource is recording the loss or gain from early derecognition of assets as depreciation expense and disclosing it separately as shown in Exhibit 4 Tab 6 Schedule 1.

In order to comply with IFRS requirements, Enersource has set up processes to enable tracking items of plant removed from the distribution system.

Currently, Enersource uses its Automated Mapping / Facilities Management / Geographical Information System ("AM/FM/GIS") to track all assets in the distribution system and to record various attributes relating to the assets. AM/FM captures both graphical (GIS) and database information pertaining to Enersource's field equipment. The AM/FM consists of a map of the City of Mississauga including all streets and lots, with the location of Enersource

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[7] OEB proceeding EB-2008-0408 resulted in the issuance of the *Report of the Board, Transition to IFRS*, on July 28, 2009. See page 19.

equipment and civil structures overlaid on the map in the appropriate locations, equipment attributes, and connectivity.

The equipment attributes along with equipment counts are used as data inputs to the Integrated Operating Model ("IOM") system, the annual asset condition assessment ("ACA") and the asset management plan ("AMP"). Enersource uses these sources of data to assess the status of the assets in its distribution system.

These informational tools and the related IT systems support Enersource's determination of the capital and operational investments to be made in the system, and will continue to increase the sophistication of Enersource's preparation for significant infrastructure replacement starting in the next four to five years. Enersource's asset investment and replacement approach is prudently managed, to achieve the lowest long-term owning cost of the distribution equipment while meeting the needs and expectations of Enersource's customers with respect to performance and reliability.

In order to calculate the value of items removed prematurely from the system, a linkage was established between the fixed asset financial system (JDE) and the GIS component of AM/FM. At the end of 2010, a dedicated attribute for each asset in AM/FM, based on year of acquisition, was populated with a financial asset number that links it to the financial information.

Reporting tools were developed in order to extract this information periodically in order to show differences in items of plant currently installed in the field for each period.

As discussed at Exhibit 2 Tab 2 Schedule 2, Enersource has implemented new asset management and planning initiatives, including the utilization of

additional tools and new processes, and has future software enhancements planned to assist with meeting the derecognition requirements under IFRS.

In the future, the AM/FM system will also record all maintenance activities, equipment failure data, and other transaction history for each item of plant.

As result of the AM/FM and JDE linkage put in place due to IFRS, Enersource incurred a write off of $1,859 for 2011 which has been coded to depreciation expense for the purpose of this application.

The write-off amounts forecast for 2012 to 2014 are shown in Table 14 below.

Table 14: Write-Off Amounts for Early Derecognition of Assets, 2011 to 2014 ($000s)

	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Early Derecognition of Assets	$ (1,859)	$ (1,924)	$ (1,981)	$ (2,041)

Depreciation for 2011 actuals and 2012 forecast for IFRS are lower compared to CGAAP due to removal of assets from the net assets balances and less capitalization of overhead costs compared to CGAAP as shown in Table 15 below.

Table 15: Depreciation Impact in 2011/2012 Due to Early Derecognition of Assets ($000s)

	2011	2012
Derecognition & Less Overhead Capitalized	$ 94	$ 292

Capitalization of Borrowing Costs

IAS 23 Borrowing Costs establishes the criteria for the recognition of interest on borrowings as a component of the carrying amount of an acquired or self-constructed item of capital assets. Borrowing costs that are directly

attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset.

Under CGAAP, rate regulated entities were permitted to include an allowance for funds used during construction ("AFUDC") in the cost of an asset that is acquired, constructed, or developed over time.

Enersource will no longer be able to capitalize AFUDC under IFRS but will be required to capitalize interest as per IAS 23. IAS 23 states that an entity can capitalize borrowing costs only on qualifying assets.

A qualifying asset is an asset that takes a substantial period of time to complete. Enersource has defined a substantial period of time as being greater than six months, and will capitalize borrowing costs for every qualifying asset or project that is expected to take longer than six months to be completed.

Since Enersource's debt is acquired on an arm's length basis, the actual borrowing costs are used. The amount of borrowing costs eligible for capitalization is determined by applying a capitalization rate to the expenditures on qualifying assets. The capitalization rate for Enersource, under IFRS, is the weighted average cost of borrowing, which was 5.0914% for 2011. This is forecast to be unchanged for 2012 through 2014 since Enersource does not anticipate any additional borrowings during this period.

Customer Contributions

Under CGAAP, Enersource recorded customer contributions as an offset to the cost of capital asset and amortized as part of the net capital asset.

Under IFRS, Enersource cannot capitalize these customer contributions as part of its net capital assets, but instead will defer the contributions as a liability and amortize them as revenue.

According to the Board Report[8]:

> *"For regulatory reporting and rate making purposes the amount of customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facility to which it relates".*

Consistent with the Board's guidance, Enersource is recording customer contributions received after January 1, 2011 as deferred revenue and amortizing them as revenue over the life of the related asset. Customer contributions received prior to this date have been netted against the cost of the related asset as a result of deemed cost election chosen for IFRS 1.

For the purpose of this Application, capital contributions are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense.

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[8] OEB proceeding EB-2008-0408 resulted in the issuance of the *Report of the Board, Transition to IFRS*, on July 28, 2009. See page 18.

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

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Contents of this report shall not be disclosed
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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro.

@Kinectrics Inc., 2009.

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro, & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

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1 Executive Summary

1.1 Introduction

One of the aspects of switching to International Financial Reporting Standards (IFRS) methodology that Ontario's Local Distribution Companies (LDCs) are embarking upon is trying to align the time period assets are amortized over with their actual useful life.

This is a rather onerous task because LDCs own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Moreover, some assets are comprised of several components that may have differing useful life than the assets themselves. It is therefore important for LDCs to properly account for the useful lives of assets and their components to facilitate conversion to IFRS.

This report reviews the useful lives of the assets, and their components that are applicable to Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro and Milton Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all listed in Section 35 of this Report. Useful lives of assets are dependent on a number of utilization factors (mechanical stress, electrical loading, environmental factors and operating practices) that are described in more detail in Section 1.4 of this report and it is worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

1.2 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by the Consortium members. The typical parent system(s) to which the asset belongs is provided and these "parent" systems are: *Overhead Lines* (OH), *Transmission Stations* (TS), *Municipal Stations* (MS), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism of each asset category is described for each asset category and when applicable assets are sub-categorized into components: components are included when their cost is material enough and, at the same time, component could be replaced without a need to replace the whole asset. For each asset or component, the following information is presented:

- Useful Life Range
- Typical Life
- Typical time-based maintenance intervals, if applicable
- Impact of Utilization Factors

Section 1.4 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

1.3 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by Consortium, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

- The initial list of assets and components was produced by the Consortium members to Kinectrics for review.
- Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.
- The intermediate list was reviewed jointly by the Consortium members and Kinectrics to derive a "final" list.
- For each asset and component in the "final" list, Kinectrics then gathered the information described in Section 1.2 from the sources described in Section 1.1 of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was then produced.
- This Draft Report was reviewed by the Consortium members and their feedback was incorporated in the Final Report.

1.4 Definition of Terms

1.4.1 *Typical Distribution System Asset*

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

1.4.2 *Component*

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

- Its value is significant enough, relative to the asset value.
- A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

1.4.3 *Useful Life*

Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report, the useful life range, in years, is presented in terms of a minimum, maximum, and typical value. An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. An overwhelming majority of the units within this class will perform as required for at least 20 years. Very little number units will operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in Utilization Factors described below.

1.4.4 *Typical Life*

Refers to the typical age at which the asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

1.4.5 *Typical Time-based Maintenance Intervals*

For the purposes of this report, time-based maintenance refers to either *Routine Inspections* (RI) or *Routine Testing/Maintenance* (RTM). Other maintenance techniques such as Condition Based Maintenance, Reliability Centered Maintenance, and more intrusive periodic overhauls are very much dependent on individual utility's maintenance strategy and practices and, as such, could not be included in compiling industry-wide typical values.

Typical time-based maintenance intervals will be given only for assets that are proactively maintained, i.e. assets for which useful life is affected by regular planned maintenance. This excludes assets that are not routinely maintained.

1.4.6 *Impact of Utilization Factors*

For the purpose of this report, stress that impacts the assets refers to *Mechanical Stress* (MC), *Electrical Loading* (EL), *Environmental Conditions* (EN) and/or *Operating Practices* (OP):

- Mechanical stress includes factors such as wind and ice that leads to degradation over time
- Electrical loading refers to either constant loading that creates long term degradation or temporary overloading that may causes a severe degradation
- Environmental conditions include pollution, salt, acid rain, extreme temperature and detrimental animals (i.e. woodpeckers) that may cause degradation over time
- Operating practices refers to how frequently an asset is subject to operating procedure (automatic or manual) that impacts its useful life, e.g. reclosers operations.

Each asset could be impacted by one or more of these factors resulting in a different degradation rates for the same assets and/or components in different jurisdictions. Therefore, it is expected that some of the utility specific typical life values would be different than the ones provided in this report based on the qualitative assessment of the above factors.

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for Consortium assets.

Table 1-1 Summary of Componentized Assets

Report Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life *(years)*			Maint. Type**	Time Based Maint. Schedule *(years)*	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
2	OH	Wood Poles	Pole		40	44	50	RI	15	MC, EN	[1], [2], [3], [4], [38],[39], [40]
			Cross Arm	Wood	20	40	50				
				Composite	40	60	80				
				Steel	20	70	100				
			Bracket	Galvanized Steel	20	40	50				
			Insulator	Composite	10	20	45				
				Porcelain	40	40	50				
			Anchors & Guying		20	40	50				
3	OH	Concrete Poles	*Refer to Wood Poles (1)*		50	60	60	RI	15	MC, EN	[5], [6]
4	OH	Steel Poles	*Refer to Wood Poles (1)*		60	60	80	RI	15	MC, EN	[7], [8], [41]
5	OH	Composite Poles	*Refer to Wood Poles (1)*		50	70	100	N/A	N/A	MC	[9]

* OH = Overhead Lines TS=Transmission Stations MS=Municipal Stations UG=Underground Systems S=Monitoring & Control System
** RI=Routine Inspection RTM=Routine Testing/Maintenance
*** MC=Mechanical Stress EL=Electrical Loading EN=Environmental Factors OP=Operating Practices

Report Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life (years)			Maint. Type**	Time Based Maint. Schedule (years)	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
6	OH	Wires	Conductor	ACSR	50	60	77	N/A	N/A	MC, EL, EN	[5], [10]
				AAC	50	60	77				
				Cu	50	60	77				
				Insulated wire	50	60	77				
			Arrester								
7	OH	Pole Mounted Transformers	Transformer		30	40	60	N/A	N/A	EL, EN	[5]
			Arrester								
8	OH	Manual Overhead Line Switches			30	50	60	RTM	2	EL, EN	[6]
9	OH	Local Motorized Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[6]
			Motor		15	20	20				
10	OH	Remote Automated Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[11], [12]
			Motor		15	20	20				
			RTU		15	20	30				
11	OH	Fuse Cutouts			30	40	60	N/A	N/A	EL, EN	[6]
12	OH	Voltage Regulator			15	20	40	N/A	N/A	EL, EN, OP	[5], [42]

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Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
13	OH	Reclosers	Breaker	Vacuum	30	40	40	RTM	10	EL, OP	[5], [6], [11], [12]
				Oil	30	42	60				
			RTU		15	20	30				
14	TS	Station Service Transformers	Dry Type		20	30	40	RTM	3	EL, EN	[1],[13], [45],[46]
			Other		32	45	55				
15	TS	TS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
16	MS	MS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
17	MS	DC Station Service	Battery bank		10	20	30	RTM	1	EL, EN, OP	[6],[17], [18],[19]
			Charger		20	20	30				
18	MS	Air Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				

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Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
19	MS	Gas Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				
20	MS	Building	Building		30	50	80	RI	1	MC, EN	[13]
			Roof		15	20	20				
			Fence		30	35	45				
21	MS	Station Grounding System			25	40	50	N/A	N/A	EN	[13],[22], [23]
22	UG	UG Primary Cables	TR-XLPE	In Duct	40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
				In Concrete Encased Duct	40	40	60				
				Direct Buried	20	25	40				
			Termination		25	40	60				
			Arrester								
23	UG	UG Secondary Cables	PI (polyethylene insulated)		40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
			PIJ (PVC jacket)		40	40	60				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
24	UG	Distribution Transformer	Transformer	Pad Mounted	30	40	40	N/A	N/A	EL, EN, OP	[5],[4], [6]
				Vault	30	40	40				
				Submersible	25	35	40				
			Elbows and Inserts		20	40	60				
25	UG	Pad Mounted Switchgear	Air Insulated		20	30	40	RI	3	EL, EN, OP	[26],[27], [28]
			Gas Insulated		30	30	50				
			Solid Dielectric		30	30	50				
26	UG	Vault Switch	Metal Enclosed Switch		20	30	40	RI	3	EL, EN, OP	[6],[26], [27]
			Metal Enclosed Cutout		30	40	60				
27	UG	Utility Chamber			50	60	80	RTM	3	EN	[5],[6], [29]
28	UG	Duct	Duct Bank		30	50	80	N/A	N/A	EN	[5],[6], [30]
			Direct Buried Pipe (PVC)		30	50	75				
			HDPE		50	50	100				
29	UG	Transformer and Switchgear Foundations			30	60	80	RTM	3	EN	[5],[6]
30	UG	Junction Cubicle			25	40	50	N/A	N/A	EN	[5]
31	S	"Classic" SCADA	RTU		15	20	30	N/A	N/A	OP	[1],[11], [12],[32]
			Relay		20	30	50				
			Battery		5	10	10				

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Section #	Parent*	Asset Category	Componentization *(sub category)*		Useful Life			Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
					Minimum	Typical	Maximum				
32	S	IED Based SCADA	IED		10	15	15	N/A	N/A	OP	[13],[32], [33]
			Battery		5	10	20				
33	S	Fault Indicators	Overhead		5	10	20	N/A	N/A	EN	[34], [47]
			Underground		10	20	30				
34	S	Metering	Meter	Residential	20	30	45	N/A	N/A	EN	[5],[35], [36]
				Industrial	20	30	60				
				Wholesale	20	30	60				
			CT		30	45	50				
			PT		30	45	50				
35	S	Smart Metering	Smart Meter		15	15	20	N/A	N/A	EN	[5],[37]
			Repeaters		5	10	15				
			Antennas								
			Data Concentrator	Sockets & Poles	10	20	20				
			Powerline Repeaters		5	10	15				
			Sky Pilot Devices								
			WAN Equipment								

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2 Wood Poles

The asset referred to in this category is the fully dressed wood pole ranging in size from 30 to 75 feet. This includes the wood pole, cross arm, bracket, insulator, and anchor & guys. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines.

The most significant component of this asset is the wood pole itself. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

2.1 Degradation Mechanism

The end of life criteria for wood poles includes loss of strength, functionality, or safety (typically due to rot, decay, or physical damage). As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

2.2 System Hierarchy

Wood poles are considered to be a part of the Overhead Lines asset grouping.

2.3 Useful Life and Typical Life

The overall useful life of a wood pole is in the range of 40 to 50 years; the typical life is 44 years.

This asset also has several major components, each with a different useful life:

- Cross Arm (Wood, Composite, Steel)
- Bracket (Galvanized Steel)
- Insulator (Composite, Porcelain)
- Anchor and Guying

2.3.1 *Cross Arm*

The useful life of a wood cross arm is in the range of 20 to 50 years; the typical life is 40 years.

The useful life of a composite cross arm is in the range of 40 to 80 years; the typical life is 60 years.

The useful life of a steel cross arm is in the range of 20 to 100 years; the typical life is 70 years.

2.3.2 *Bracket (Galvanized Steel)*

The useful life of an aluminum bracket component ranges from 20 to 50 years, with a typical value of approximately 40 years.

2.3.3 *Insulator*

The useful life of a composite insulator is in the range of 10 to 45 years; the typical life is 20 years.

The useful life of a porcelain insulator is in the range of 40 to 50 years, with a typical life of 40 years.

2.3.4 *Anchors and Guying*

The useful life of anchors and guying is in the range of 20 to 50 years; the typical life is 40 years.

2.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

2.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

3 Concrete Poles

This asset category includes the concrete pole with the same components as for the wood poles, namely cross arm, bracket, insulator, and anchor. These poles range in size from 35 to 80 feet, with the typical pole being 60 feet.

3.1 Degradation Mechanism

The most significant component in this class is the concrete pole itself. Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in), however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice, resulting in cracking and separation of the concrete. The spun concrete process used in manufacturing poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

3.2 System Hierarchy

Concrete poles are considered to be a part of the Overhead Lines assets grouping.

3.3 Useful Life and Typical Life

The useful life range of the concrete pole component is 50 to 60 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

3.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

3.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

4 Steel Poles

This asset category includes the directly buried steel pole, cross arm, bracket, insulator, and anchor.

4.1 Degradation Mechanism

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground. In-ground situations are vastly different because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground.

There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations.

Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

4.2 System Hierarchy

Steel poles are considered a part of the Overhead Lines asset grouping.

4.3 Useful Life and Typical Life

The useful life of steel poles is in the range of 60 to 80 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

4.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

4.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

5 Composite Poles

This asset category includes the composite pole, cross arm, bracket, insulator, and anchor. At Consortium the composite poles are fiberglass.

5.1 Degradation Mechanism

The most significant component in this class is the composite pole itself. The major degradation of composite poles is ultra violet (UV) degradation. It represents an attack from ultra-violet radiation, which might result in crack or disintegration in composite poles. It is a common problem in products exposed to sunlight. Continuous exposure is a more serious problem than intermittent exposure, since attack is dependent on the extent and degree of exposure. In fiber products like composite poles, useful life will be shortened because the outer fibers will be attacked first, and will easily be damaged by abrasion. This will end up with fiber blooming and fading.

5.2 System Hierarchy

Composite poles are considered to be a part of the Overhead Lines assets grouping.

5.3 Useful Life and Typical Life

The useful life range of the composite pole component is 50 to 100 years; the typical life is 70 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

5.4 Time Based Maintenance Intervals

. Composite poles are not subject to planned maintenance.

5.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress.

6 Wires

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, and insulated wire.

6.1 Degradation Mechanism

To function properly, conductors must retain both their conductive properties and mechanical (i.e. tensile) strength. Aluminum conductors have three primary modes of degradation: corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation.

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

Fatigue degradation presents greater detection and assessment challenges than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes. However, under normal operating conditions, with proper design and application of vibration control, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases detectable indications of fatigue may only exist during the last 10% of a conductor's life.

In designing transmission lines, engineers ensure that conductors receive no more than 60% of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor's RTS, significant sag occurs, requiring either resagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminum

strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

6.2 System Hierarchy

The Wire asset category belongs to the Overhead Lines assets grouping.

6.3 Useful Life and Typical Life

The useful life of conductors is in the range of 50 to 77 years; the typical life is 60 years.

6.4 Time Based Maintenance Intervals

Overhead conductors are not subject to planned maintenance.

6.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress, Electrical Loading and Environmental Conditions.

7 Pole Mounted Transformers

Distribution pole top mounted transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

7.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

7.2 System Hierarchy

The Pole Mounted Transformer asset category belongs to the Overhead Lines assets grouping.

7.3 Useful Life and Typical Life

The useful life of the pole mounted transformer is in the range of 30 to 60 years, with a typical value close to 40 years.

7.4 Time Based Maintenance Intervals

Pole mounted distribution transformers are not subject to planned maintenance.

7.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

8 Manual Overhead Line Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

8.1 Degradation Mechanism

The main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

8.2 System Hierarchy

Overhead Switches asset category belongs to the Overhead Lines assets grouping.

8.3 Useful Life and Typical Life

The useful life of manually operated switches is in the range of 30 to 60 years; the typical life is 50 years.

8.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for manually operated overhead switches is two years.

8.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

9 Local Motorized Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches and a motor. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism is controlled by a motor.

9.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with local motorized overhead switches include the following:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of degradation are a function on operating duties and environment.

9.2 System Hierarchy

Local Motorized Overhead Switches category belongs to the Overhead Lines assets grouping.

9.3 Useful Life and Typical Life

The local motorized overhead switch can be componentized into two components:

- Switch
- Motor

9.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead switch in section 8.3 of this report).

9.3.2 *Motor*

The useful life of the motor of local motorized switches is in the range of 15 to 20 years; the typical life is about 20 years.

9.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for local motorized switches is every two years.

9 Local Motorized Overhead Line Switches

9.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

10 Remote Automated Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions and operate only when the current through the switch is zero. Most distribution line switches are rated 600 to 900 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in open position. This component also consists of a remote terminal unit (RTU) component.

10.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

10.2 System Hierarchy

Remote Automated Overhead switches asset category belongs to the Overhead Lines assets grouping.

10.3 Useful Life and Typical Life

The remote automated overhead switch can be componentized into three components:

- Switch
- Motor
- Remote Terminal Unit (RTU)

10 Remote Automated Overhead Line Switches

10.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead Switch in section 8.3 of this report).

10.3.2 *Motor*

The useful life of a motor is in the range of 15 to 20 years; the typical life is 20 years (the same as for Local Motorized Overhead Switch in section 9.3.2 of this report).

10.3.3 *Remote Terminal Unit (RTU)*

The useful life of an RTU is in the range of 15 to 30 years; the typical life is 20 years.

10.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for remote automated overhead switches is every two years.

10.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

11 Fuse Cutouts

This asset is applied on overhead transformers, capacitors, cables or lines. Fuse Cutouts will interrupt all faults including low current that will melt the fuse link and high rated interrupting current so long as the system is under realistic transient-recovery-voltage conditions.

11.1 Degradation Mechanism

The major degradation of fuse cutouts is on fuse body. There are several degradation modes in practice including the production of carbon from organic materials in the fuse, generation of water vapor to assist current interruption and electrical breakdown in high stress areas of the core.

The production of carbon from organic materials in the fuse body is one degradation mode in practice. This carbon is not produced until a particular body temperature is reached, and the time for this to occur depends on the fuse design. The most critical factors would appear to include the heat generated in the fulgurite, the distance between the fulgurite and the fuse body, the thermal conductivity of the filler material, and the breakdown temperature of the organic material.

For some fuses that generate water vapor to assist current interruption, the water is deposited on the inside surface of the body. Treeing is observed on the surface, ultimately leading to a steady increase in leakage current until failure.

For the fuse cores that contain organic material, hollow core is developed at high temperature due to release of water molecules, resulting in electrical breakdown in high stress areas of the core in certain designs.

11.2 System Hierarchy

Fuse Cutouts asset category belongs to the Overhead Lines assets grouping.

11.3 Useful Life and Typical Life

The useful life of fuse cutouts is in the range of 30 to 60 years; the typical life is 40 years.

11.4 Time Based Maintenance Intervals

Fuse Cutouts are not subject to planned maintenance

11.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

12 Voltage Regulators

Voltage regulators are static devices that perform step-up and step-down voltage change operations. Distribution line transformers change the medium or low distribution voltage to 120/240 V or other common voltages for use in residential and commercial applications.

12.1 Degradation Mechanism

It has been demonstrated that the life of the voltage regulator's internal insulation is related to temperature-rise and duration. Therefore, voltage regulator life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of voltage regulators.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of voltage regulator that should be selected for a given number and type of customers to obtain optimal life. There is also the operating practices affect on voltage regulators. If it is a strong system, the voltage regulator may not need to step-up or step-down the voltage, in which case there would be less stress on the device itself.

12.2 System Hierarchy

Voltage Regulators asset category belongs to the Overhead Lines assets grouping.

12.3 Useful Life and Typical Life

The useful life of voltage regulators is in the range of 15 to 40 years; the typical life is 20 years.

12.4 Time Based Maintenance Intervals

Voltage Regulators are not subject to planned maintenance.

12.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

13 Reclosers

This asset class consists of light duty circuit breakers equipped with interrupters that use controllers. This is where the breaking and making of fault current takes place. The interrupters use oil of vacuum as the insulating agent. The controllers are either hydraulic or electric. It is designed for single phase or three phase use, depending on the model.

13.1 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect suppression devices as well as the contacts, the oil, and the arc control. The degradation of these devices depends on the prevailing fault, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism mal-function. For deterioration, exposure to weather is a potentially significant degradation process – primarily corrosion of the tank and other metallic components and deterioration of bushings.

13.2 System Hierarchy

Recloser asset category belongs to the Overhead Lines assets grouping.

13.3 Useful Life and Typical Life

Reclosers can be categorized into two components:

- Breaker (Vacuum, Oil)
- RTU

13.3.1 *Breaker*

The useful life of Vacuum breakers is in the range of 30 to 40 years; the typical life is 40 years.

The useful life of Oil breakers is in the range of 30 to 60 years; the typical life is 42 years.

13.3.2 *RTU*

The useful life of recloser RTUs is in the range of 15 to 30 years; the typical life is 20 years.

13.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for the breaker component of reclosers is every ten years.

13 Reclosers

13.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Operating Practices.

14 Station Service Transformers

The station service transformers are the small transformers are configured to provide power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. This report refers to both to both dry type and other types of transformers.

14.1 Degradation Mechanism

As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

For dry type transformers, the major degradation factors are dirt and moisture. Dirt will contaminate insulation surfaces allowing the formation of conductive paths along the surfaces and eventually to ground. In the case of ventilated dry type transformers, the windings are in direct contact with the air. External air-carrying contaminants or excessive moisture could reduce winding insulation. Dust and dirt accumulation can also reduce air circulation through windings, which eventually shorten the life expectancy of a dry type transformer.

14.2 System Hierarchy

Station service transformers are considered part of the Transmission Stations assets grouping.

14.3 Useful Life and Typical Life

The useful life of a station service transformer is based on the transformer type:

- Dry Type
- Other

14.3.1 *Dry Type*

The useful life of dry type station service transformers is in the range of 20 to 40 years; the typical life is 30 years.

14.3.2 *Other*

The useful life of other station service transformers is in the range of 32 to 55 years; the typical life is 45 years.

14.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is three years.

14.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions. If this device is running within an electrically stable system there will be less stress imposed on it.

15 TS Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA. The Consortium typically uses TS Power Transformers rated 75/125 MVA.

15.1 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

15.2 System Hierarchy

Power Transformers belong to the Transformer Stations assets grouping.

15.3 Useful Life and Typical Life

This asset could be componentized into the following components:

- Winding
- Manual/Automatic On Load Tap Changer

15.3.1 *Winding*

The useful life of the winding can be in the range of 32-55 years, depending on the loading condition and ambient operating temperature, and routine maintenance practices. A typical life of 45 years can be expected for the winding system.

15.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic on load tap changer, assuming it is vacuum type, is 20-60 years; the typical life is 20 years.

15.4 Time Based Maintenance Intervals

For TS power transformers, the typical routine testing/maintenance interval is two years.

15.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

16 MS Power Transformers

Power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA. The Consortium typically uses MS Power Transformers rated 20/33.3 MVA.

16.1 Degradation Mechanism

The degradation of the power transformers at municipal stations or at customer sites is similar to that of the transformers at transmission stations. These transformers are subject to electrical, thermal, and mechanical aging. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

16.2 System Hierarchy

MS Power Transformer asset category belongs to the Municipal Stations assets grouping.

16.3 Useful Life and Typical Life

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Winding
- Manual/Automatic On Load Tap Changer

16.3.1 *Winding*

The useful life of windings is 32 to 55 years; the typical life is 45 years.

16.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic tap changer, assuming it is vacuum type, is 20 to 60 years; the typical life is 20 years.

16.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

16.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically sound system there will be less stress imposed on it.

17 DC Station Service

The DC station service asset class includes battery banks and chargers. Equipment within transmission and municipal stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power so the only guaranteed instantaneous power source must be DC, based on batteries.

17.1 Degradation Mechanism

Effective battery life tends to be much shorter than many of the major components in a station. The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service are still relatively frequent. For this reason, many utilities employ battery monitors and alarm systems. The earlier versions of these are still widely used and are relatively unsophisticated devices that measure basic battery parameters with pre-set alarm levels. More modern monitoring devices have the ability to identify a potential failure as it develops and to provide a warning.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves. Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

17.2 System Hierarchy

DC station services belong to Municipal Stations assets grouping.

17 DC Station Service

17.3 Useful Life and Typical Life

This asset also has two major components that have differing useful lives:

- Battery Banks
- Charger

17.3.1 *Battery Bank*

The battery bank has a useful life range of 10 to 30 years; typical life is 20 years.

17.3.2 *Charger*

The charger has a useful life range of 20 to 30 years; typical life is 20 years.

17.4 Time Based Maintenance Intervals

Typically, routine testing/maintenance for batteries are conducted annually. The maintenance of schedule battery chargers is typically coordinated with that of the battery.

17.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. This device cannot be overloaded, last longer when there is not extreme cold weather conditions and only the battery bank component is affected by operating practices (i.e., it only runs if the AC fails).

18 Air Insulated Switchgear

Air Insulated Switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium voltage range, from 4.16 to 44 kV. The switchgear includes breakers; disconnect switches, or fusegear, current transformers (CTs), voltage transformers (VTs) and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The gear is modular in that each breaker is enclosed in its own metal envelope (cell). The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

18.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Correct operation of the mechanism is critical in devices that make or break fault currents, i.e. the contact opening and closing characteristics must be within specified limits. The greatest cause of mal-operation of switchgear is related to mechanism malfunction. Deterioration due to corrosion or wear due to lubrication failure may compromise mechanism performance by either preventing or slowing down the operation of the breaker. This is a serious issue for all types of switchgear.

In older air filled equipment, degradation of active solid insulation (for example drive links) has been a significant problem for some types of switchgear. Some of the materials used in this equipment, particularly those manufactured using cellulose-based materials (pressboard, SRBP, laminated wood) are susceptible to moisture absorption. This results in a degradation of their dielectric properties that can result in thermal runaway or dielectric breakdown. An increasingly significant area of solid insulation degradation relates to the use of more modern polymeric insulation. Polymeric materials, which are now widely used in switchgear, are very susceptible to discharge damage. These electrical stresses must be controlled to prevent any discharge activity in the vicinity of polymeric material. Failures of relatively new switchgear due to discharge damage and breakdown of polymeric insulation have been relatively common over the past 15 years.

Temperature, humidity and air pollution are also significant degradation factors, so indoor units tend to have better long-term performance. The safe and efficient operation of switchgear and its longevity may all be significantly compromised if the substation environment is not adequately controlled. In addition, the air switchgear can tolerate less number of full fault operations before maintenance is required.

18 Air Insulated Switchgear

18.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

18.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

18.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

18.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

18.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

18.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

19 Gas Insulated Switchgear

The latest design of metalclad gear is the Gas Insulated Switchgear (GIS), which uses low-pressure SF6 gas as a general insulation medium, as a replacement for the air. The insulation within the metal enclosure is not necessarily the same as the working fluid in the breakers themselves, which presently is either SF6 or vacuum.

19.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Generally, mechanism malfunction causes most operational problems in GIS. Corrosion and lubrication failure may compromise mechanism performance by preventing or slowing its operation.

Solid insulation such as that in entrance bushings, internal support insulators, plus breaker and switch operating rods have caused many GIS failures. Manufacturing, shipping, installing, maintaining and operating the GIS can cause defects in the insulation. Defects include voids in epoxy insulators, delamination of epoxy and metallic hardware, and protrusions on conductors. In floating components, fixed and moving particles can lead to failures. Partial discharge (PD) activity usually leads to flashovers.

Corrosion and general deterioration increase risks of moisture ingress and SF6 leaks, particularly in outdoor GIS. If not treated, these factors may cause the end-of-life for GIS.

GIS is designed and manufactured for outdoor use, but it generally has better long-term performance when installed indoors. Outdoor GIS, particularly older ITE designs, have higher than acceptable SF6 gas leaks because of the poor quality of fittings, connectors, valves, by-pass piping, general enclosure porosity and flange corrosion. Indoor installations reduce problems from corrosion, moisture ingress, low ambient temperatures and SF6 leaks.

GIS have more costly, difficult and time-consuming post fault maintenance requirements than air insulated switchgear. Older GIS have even more post-fault maintenance problems. Accessibility, fault location, fault level and duration, degree of compartmentalization, isolation requirements, pressure relief, burn-through protection, parts and service capabilities all help determine post-fault maintenance needs.

19.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

19 Gas Insulated Switchgear

19.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

19.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

19.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

19.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

19.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

20 Building

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building itself (foundations, walls), roof, and fence.

20.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings. It is the potential water ingress with poses the most danger to the asset due to the presence of electrical equipment. In order to prevent this, the buildings must be weatherproof.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

20.2 System Hierarchy

Building asset category belongs to the Municipal Stations assets grouping.

20.3 Useful Life and Typical Life

The overall useful life range of the building itself is 30 to 80 years; the typical life is 50 years.

20 Building

This asset also has two other major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Roof
- Fence

20.3.1 *Roof*

The useful life of the roof can be in the range of 15 to 20 years, with a typical life of 20 years.

20.3.2 *Fence*

The useful life range of the fence is 30 to 45 years, with a typical life of 35 years.

20.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is every year.

20.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

21 Station Grounding System

The station grounding system asset refers to grounding rods and connectors. Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system.

21.1 Degradation Mechanism

Station grounding systems keep ground potential rise, step and touch potentials below specified limits when maximum (i.e. worst case) ground faults occur. Under fault conditions, the following factors determine step and touch potentials:

- Magnitude of the fault current
- Resistance of ground combined with the ground grid consisting of station electrodes, transmission line sky wires and distribution neutrals
- Ground resistivity of upper and lower layers of earth.

Increases in system capacity and fault currents at a station may lead to unacceptable performance of the ground grid. Corrosion of buried conductors and connectors, mechanical damage to buried electrodes, plus burning-off of grounding conductors and connectors during heavy fault currents also may lead to unsatisfactory performance. Further, changes in resistivity of upper or lower layers of earth may adversely affect ground grid characteristics.

21.2 System Hierarchy

Station Grounding Systems asset category belongs to the Municipal Stations assets groupings.

21.3 Useful Life and Typical Life

Station grounding systems have a useful life range of 25 to 50 years; the typical life is 40 years.

21.4 Time Based Maintenance Intervals

Station Grounding Systems are not subject to planned maintenance.

21.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

22 Underground Primary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The initial capital cost of a distribution underground cable circuit is three or more times the cost of an overhead line of equivalent capacity and voltage. The cross linked polyethylene (XLPE) cable is the type of underground distribution cables used by Consortium. While XLPE underground cable can be installed in ducts (and concrete enclosed ducts), it can also be directly buried.

Cable terminations are designed to separate the cable ground from the conductor in a safe and controlled manner. Inside the cable, ground and high voltage are separated by only a few millimeters. This distance is much too small to support any voltage. Therefore the termination must increase this separation while being able to withstand the surrounding environment.

22.1 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early polymeric cables. As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved.

The major degradation problems with the cable terminations concern mostly flashover and tracking associated with the outside and interior surfaces of the accessory. However, there are also problems of overheating at connections and voltage control at the end of the cable shield.

22 Underground Primary Cables

22.2 System Hierarchy

Underground Primary Cables asset category belongs to the Underground Systems assets grouping.

22.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type and component:

- TR-XLPE (In Duct, In Concrete Encased Duct, Direct Buried)
- Termination

22.3.1 *TR-XLPE*

The useful life range of in duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of in concrete encased duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of direct buried cable is 20 to 40 years; the typical life is 25 years.

22.3.2 *Termination*

The useful life range of termination component of underground cable is 25 to 60 years; the typical life is 40 years.

22.4 Time Based Maintenance Intervals

Underground Primary Cables are not subject to planned maintenance.

22.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

23 Underground Secondary Cables

Secondary underground cables are used to supply customer premises. The Polyethylene Insulated (PI) and PVC Jacket (PIJ) are similar to the XLPE cables described above, and are assumed to be in duct.

23.1 Degradation Mechanism

Underground secondary conductors are typically insulated with polyethylene. Polyethylene insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. These commissioning tests are an area of some concern for polyethylene cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables. However those with the PVC jacket have further insulation to prevent some deterioration of the insulation.

23.2 System Hierarchy

Underground Secondary Cables are used in the Underground system.

23.3 Useful Life and Typical Life

The underground secondary cable can be categorized into two types:

- Polyethylene Insulated
- PVC Jacket

23.3.1 *Polyethylene Insulated*

The useful life range of in polyethylene insulated cable is 40 to 60 years; the average life is 40 years.

23.3.2 *PVC Jacket*

The useful life range of in PVC jacket cable is 40 to 60 years; the average life is 40 years.

23.4 Time Based Maintenance Intervals

Underground Secondary Cables are not subject to planned maintenance

23.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

24 Distribution Transformer

This asset class consists of the transformer and elbows and inserts associated with the system. There are three types of transformers that Consortium uses: Pad Mounted, Vault and Submersible.

Pad mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. Vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil. Submersible transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

24.1 Degradation Mechanism

The pad-mounted transformer has a similar degradation mechanism to other distribution transformers. It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

The vault transformer and submersible transformer have a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

24.2 System Hierarchy

Distribution Transformers asset category belongs to the Underground Systems asset grouping.

24.3 Useful Life and Typical Life

The overall useful life range of the transformer itself is dependent on the component:

- Transformer (Pad Mounted, Vault, Submersible)
- Elbows and Inserts

24 Distribution Transformer

24.3.1 *Transformer*

The useful life range of pad mounted distribution transformers are 30 to 40 years; the typical life is 40 years.

The useful life range of vault distribution transformers is 30 to 40 years; the typical life is 40 years.

The useful life range of submersible distribution transformers is 25 to 40 years; the typical life is 35 years.

24.3.2 *Elbows and Inserts*

The useful life range of the elbows and inserts component of distribution transformers is 20 to 60 years; the typical life is 40 years.

24.4 Time Based Maintenance Intervals

Distribution Transformers are not subject to planned maintenance.

24.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. The operating practices impact only the elbows and inserts component of the asset.

25 Pad Mounted Switchgear

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 load break switches and vacuum fault interrupters. A majority of the pad mounted switchgear currently employs air-insulated gang operated load-break switches.

25.1 Degradation Mechanism

The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

25.2 System Hierarchy

Pad-Mounted Switchgear belongs to the Underground Systems assets grouping.

25.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the pad mount switchgear type:

- Air Insulated
- Gas Insulated
- Solid Dielectric

25.3.1 *Air Insulated*

The useful life range of this air insulated pad mount switchgear is 20 to 40 years; the typical life is 30 years.

25.3.2 *Gas Insulated*

The useful life range of this gas insulated pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.3.3 *Solid Dielectric*

The useful life range of this solid dielectric pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is three years.

25.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

26 Vault Switch

The vault switches used by Consortium are metal enclosed switch and metal enclosed cutout. These units are essentially pad mounted switchgear, enclosed in stainless steel containers, with the ability to be wall or ceiling mounted.

26.1 Degradation Mechanism

The degradation mechanism of this asset is similar to that of other types of pad mounted switchgear. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

26.2 System Hierarchy

Vault Switches asset category belongs to the Underground Systems assets grouping.

26.3 Useful Life and Typical Life

The overall useful life range of the vault switch is dependent on the pad mount switchgear type:

- Metal Enclosed Switch
- Metal Enclosed Cutout

26.3.1 *Metal Enclosed Switch*

The useful life range of metal enclosed switch is 20 to 40 years; the typical life is 30 years.

26.3.2 *Metal Enclosed Cutout*

The useful life range of metal enclosed cutout is 30 to 60 years; the typical life is 40 years.

26.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is 3 years.

26.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

27 Utility Chamber

Utility Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

27.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, utility chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Utility chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Utility chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a utility chamber system. Similarly, utility chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with utility chambers also requires evaluation in assessing the overall condition of a utility chamber system.

27.2 System Hierarchy

Utility Chambers asset category belongs to the Underground Systems assets grouping.

27.3 Useful Life and Typical Life

Utility chambers have a useful life range of 50 to 80 years; the typical life range is 60 years.

27.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

27 Utility Chamber

27.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

28 Duct

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually two to six inches in diameter.

28.1 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

28.2 System Hierarchy

Ducts asset category belongs to the Underground Systems assets grouping.

28.3 Useful Life and Typical Life

The overall useful life range of the duct is dependent on the type:

- Duct Bank
- Direct Buried Pipe (PVC)
- High Density Polyethylene (HDPE)

28.3.1 *Duct Bank*

The useful life range of the duct bank type is 30 to 80 years; the typical life is 50 years.

28.3.2 *Direct Buried Pipe (PVC)*

The useful life range of the direct buried pipe type is 30 to 75 years; the typical life is 50 years.

28.3.3 *High Density Polyethylene (HDPE)*

The useful life range of the HDPE type is 50 to 100 years; the typical life is 50 years.

28.4 Time Based Maintenance Intervals

Ducts are not subject to planned maintenance.

28.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

29 Transformer and Switchgear Foundations

This asset class is similar to the utility chamber asset. It is a buried pre cast concrete vault on which pad-mounted transformers or switchgear are mounted. The foundation itself is buried; however the top portion is above ground.

29.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, transformer and switchgear foundation must withstand heavy loads associated with traffic in the boulevard. When located in driving lanes, concrete vault must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Transformer and switchgear foundation degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Transformer and switchgear foundation also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a transformer and switchgear foundation. Similarly, transformer and switchgear foundation with lights that do not function properly constitute defective systems.

29.2 System Hierarchy

Transformer and Switchgear foundations asset category belongs to the Underground Systems assets grouping.

29.3 Useful Life and Typical Life

The overall useful life range of Transformer and switchgear foundation is 30 to 80 years; the typical life is 60 years.

29.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

29.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

30 Junction Cubicle

This asset class consists of a wiring box similar to pad mount switchgear. For the purposes of this study there is only reference to junction casing.

30.1 Degradation Mechanism

The main degradation associated with the junction cubicle casing is caused by outside sources. These include corrosion, vehicle damage, case rusting, and dirt or contamination.

30.2 System Hierarchy

Junction cubicle is used in the Underground Systems assets grouping.

30.3 Useful Life and Typical Life

The overall useful life range of junction cubicle casing is 25 to 50 years; the typical life is 40 years.

30.4 Time Based Maintenance Intervals

Junction Cubicles are not subject to planned maintenance

30.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

31 “Classic” SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

31.1 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

31.2 System Hierarchy

Classic SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

31.3 Useful Life and Typical Life

This asset has several major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- RTU
- Relay
- Battery

31.3.1 *RTU*

The useful life of the RTU in “classic” SCADA is in the range of 15 to 30 years; the typical life is 20 years.

31.3.2 *Relay*

The useful life of the relay in “classic” SCADA is in the range of 20 to 50 years; the typical life is 30 years.

31.3.3 *Battery*

The useful life of the battery in “classic” SCADA is in the range of 5 to 10 years; the typical life is 10 years.

31.4 Time Based Maintenance Intervals

“Classic” SCADA is not subject to planned maintenance.

31.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery and relay components that are affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

32 IED Based SCADA

Intelligent Electronic Devices (IED) based Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility.

32.1 Degradation Mechanism

Physical degradation of IED Based SCADA happens on hardware part of an IED. Compared to solid state relays, IEDs are not sensitive to ambient environment. The major contributing factor of degradation is the electrical environment, i.e. inrush transient. Since IEDs have built-in self-supervision system, the settings with perfect long time stability is guaranteed.

The failure mode of an IED can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Mal-function due to software design flaw causing software latched by external EMI interference
- Will not operate due to power supply failure

To assess the health status of an IED, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., overcurrent, distance etc.)
- Reliability, including mal-operation count, loading and age

32.2 System Hierarchy

IED Based SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

32.3 Useful Life and Typical Life

This asset has two major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- IED
- Battery

32.3.1 *IED*

The useful life of the IED in IED based SCADA is in the range of 10 to 15 years; the typical life is 15 years.

32.3.2 *Battery*

The useful life of the battery in IED based SCADA is in the range of 5 to 20 years; the typical life is 10 years.

32.4 Time Based Maintenance Intervals

IED based SCADA is not subject to planned maintenance.

32.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

33 Fault Indicators

Fault indicators are used for loaded underground distribution circuits where secondary voltage is available - pad mounted transformers, switchgear and underground vault applications. A sensor monitors the line current. When the trip rating is exceeded, the indicator trips to the fault position. To reset the display the fault indicator uses a secondary voltage source, such as the low-voltage terminals of distribution transformers.

33.1 Degradation Mechanism

Fault indicators have durable Lexan housings, and utilize coated nickel iron sensor laminations encapsulated in a polyurethane potting compound for environmental protection. Overhead fault indicators use batteries, hence their useful life is based primarily on the end of life of the battery itself. The useful life of overhead fault indicators is significantly less than underground fault indicators due to this battery component.

33.2 System Hierarchy

Fault Indicators asset category belongs to the Monitoring and Control Systems assets grouping.

33.3 Useful Life and Typical Life

The overall useful life range of the fault indicator itself is dependent on the type:

- Overhead
- Underground

33.3.1 *Overhead*

The useful life of the overhead fault indicator is based on the useful life of its battery which is in the range of 5 to 20years; the typical life is 10 years.

33.3.2 *Underground*

The useful life of the underground fault indicator is in the range of 10 to 30 years; the typical life is 20 years.

33.4 Time Based Maintenance Intervals

Fault Indicators are not subject to planned maintenance.

33.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

34 Metering

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on those meters used for residential meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT).

34.1 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

34.2 System Hierarchy

Metering asset category belongs to the Monitoring and Control Systems assets grouping.

34.3 Useful Life and Typical Life

There are two components of the meter which have their own useful and typical life:

- Meter (Residential, Industrial/Commercial, Wholesale)
- Transformer (Current, Potential)

34.3.1 *Meter*

The useful life range of residential type meter is 20 to 45 years; typical life is 30 years.

The useful life range of industrial/commercial type meter is 20 to 60 years; typical life is 30 years.

The useful life range of wholesale type meter is 20 to 60 years; typical life is 30 years.

34.3.2 *Transformer (Current, Potential)*

The useful life range of the CT component is 30 to 50 years; typical life is 45 years.

The useful life range of the PT component is 30 to 50 years; typical life is 45 years.

34.4 Time Based Maintenance Intervals

Meters are not subject to planned maintenance

34.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

35 Smart Metering

A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

35.1 Degradation Mechanism

The major degradation mechanism of smart metering system is listed as follows:

- Wiring insulation deterioration due to corrosion, moisture or overheating
- Poor electrical connections due to corrosion, vibration or other physical problems
- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

Typically, terminations and connectors experience mechanical degradation. In damp locations it is common for verdigris, which is the green coating or patina formed when copper, brass or bronze is weathered and exposed to air or seawater over a period of time, to form. Typical problems for these components include:

- Failed crimped terminations due to movement
- Cracked terminal blocks
- Stripped threads
- Mechanical damage from over tightening

Typical degradation processes for the cabinets or racks include:

- Corrosion
- Loss of mechanical strength through use (e.g. swing front panels)

Microwave electronics in smart metering system range from capacitors and resistors to solid-state printed circuit boards. All electronic components have finite lifetimes. Modern highly integrated electronic equipment consists of application specific integrated circuits, surface mounted components, and multi-layer boards.

35 Smart Metering

35.2 System Hierarchy

Smart Metering asset category belongs to the Monitoring and Control Systems assets grouping.

35.3 Useful Life and Typical Life

There are several components of the smart meter which have their own useful and typical life:

- Smart Meter
- Repeater
- Data Concentrator
- Powerline Repeaters

35.3.1 *Smart Meter*

The useful life range of the smart meter is 15 to 20 years; typical life is 15 years.

35.3.2 *Repeater*

The useful life range of the repeater is 5 to 15 years; typical life is 10 years.

35.3.3 *Data Concentrator*

The useful life range of the data concentrator is 10 to 20 years; typical life is 20 years.

35.3.4 *Powerline Repeaters*

The useful life range of the powerline repeater is 5 to 15 years; typical life is 10 years.

35.4 Time Based Maintenance Intervals

Smart Meters are not subject to planned maintenance

35.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

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Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2008 CGAAP**

					Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Useful life**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals /Retirements**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals /Retirements**	**Closing Balance**	**Net Book Value**
N/A	1905	Land	N/A	N/A	$ 4,071	$	$ ()	$ 4,070	$ -	$ -	$ -	$ -	$ 4,070
1	1808	Buildings and Fixtures	50-60	1.67%-2%	$ 13,424	$ 491	$ -	$ 13,915	$ (4,678)	$ (242)	$ -	$ (4,920)	$ 8,996
1	1808	Buildings and Fixtures (Improvements)	25	4.00%	$ 1,905	$ 793	$ -	$ 2,698	$ (369)	$ (92)	$ -	$ (461)	$ 2,237
47	1820	Distribution Station Equipment <50 kV	30	3.33%	$ 67,914	$ 4,762	$ (2,214)	$ 70,462	$ (27,682)	$ (2,330)	$ 2,214	$ (27,798)	$ 42,664
47	1830	Poles, Towers & Fixtures	25	4.00%	$ 160,579	$ 12,912	$ (1,516)	$ 171,975	$ (62,071)	$ (6,681)	$ 1,516	$ (67,236)	$ 104,738
47	1840	Underground Conduit	25	4.00%	$ 425,599	$ 18,454	$ (1,149)	$ 442,904	$ (184,796)	$ (17,137)	$ 1,149	$ (200,784)	$ 242,120
47	1850	Line Transformers	25	4.00%	$ 68,462	$ 548	$ (885)	$ 68,124	$ (42,658)	$ (2,673)	$ 885	$ (44,446)	$ 23,678
47	1860	Meters	25-35	2.86%-4.00%	$ 33,503	$ 966	$ (2,398)	$ 32,070	$ (18,057)	$ (1,256)	$ 291	$ (19,022)	$ 13,049
47	1860	Meters (Smart Meters New Condos)	15	6.67%	$ -	$ 1,253	$ -	$ 1,253	$ -	$ (47)	$ -	$ (47)	$ 1,206
47	1555	Meters (Smart Meters)	15	6.67%	$ 7,641	$ 5,596	$ -	$ 13,236	$ (263)	$ (687)	$ -	$ (950)	$ 12,286
50	1555	Computer Equip - Smart Meters	5	20.00%	$ 331	$ 511	$ (47)	$ 795	$ (85)	$ (199)	$ 47	$ (237)	$ 557
8	1915	General Equipment & Office Furniture	10	10.00%	$ 5,341	$ 509	$ (76)	$ 5,774	$ (1,647)	$ (555)	$ 15	$ (2,187)	$ 3,587
50	1920	Computer Equip.-Hardware	5	20.00%	$ 6,936	$ 493	$ (2,719)	$ 4,710	$ (2,955)	$ (2,319)	$ 2,719	$ (2,556)	$ 2,154
12	1925	Computer Software	10	10.00%	$ 1,414	$ 1,329	$ -	$ 2,744	$ (1,019)	$ (100)	$ -	$ (1,118)	$ 1,625
12	1925	Computer Software	2	50.00%	$ 299	$ 520	$ -	$ 818	$ (266)	$ (100)	$ -	$ (366)	$ 452
10/10.1	1930	Transportation Equipment (4 years)	4	25.00%	$ 475	$ 229	$ (250)	$ 454	$ (230)	$ (95)	$ 172	$ (152)	$ 302
10	1930	Transportation Equipment (5 years)	5	20.00%	$ 2,576	$ 193	$ (211)	$ 2,558	$ (1,385)	$ (417)	$ 211	$ (1,590)	$ 968
10	1930	Transportation Equipment (8 years)	8	12.50%	$ 12,768	$ 1,104	$ (1,675)	$ 12,197	$ (8,776)	$ (892)	$ 1,662	$ (8,006)	$ 4,190
8	1940	Tools, Shop & Garage Equipment	10	10.00%	$ 1,478	$ 256	$ (137)	$ 1,597	$ (639)	$ (154)	$ 137	$ (655)	$ 942
47	1980	System Supervisor Equipment	15-25	4%-6.67%	$ 13,883	$ 1,102	$ (761)	$ 14,224	$ (6,811)	$ (840)	$ 761	$ (6,889)	$ 7,335
47	1995	Contributions & Grants - Overhead	25	4.00%	$ (5,271)	$ (2,651)	$ -	$ (7,922)	$ 905	$ 264	$ -	$ 1,169	$ (6,753)
47	1995	Contributions & Grants - Transformers	25	4.00%	$ (8,056)	$ (548)	$ -	$ (8,604)	$ 1,559	$ 333	$ -	$ 1,892	$ (6,712)
47	1995	Contributions & Grants - Underground	25	4.00%	$ (57,095)	$ (4,452)	$ -	$ (61,547)	$ 9,529	$ 2,373	$ -	$ 11,902	$ (49,646)
N/A	2055	Construction in Progress - CIAC	N/A	N/A	$ (1,081)	$ 735	$ -	$ (346)	$ -	$ -	$ -	$ -	$ (346)
N/A	2055	Construction in Progress - Substation Equip	N/A	N/A	$ 1,013	$ 621	$ -	$ 1,633	$ -	$ -	$ -	$ -	$ 1,633
N/A	2055	Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 651	$ 47	$ -	$ 698	$ -	$ -	$ -	$ -	$ 698
N/A	2055	Construction in Progress - Overhead	N/A	N/A	$ 2,754	$ (1,246)	$ -	$ 1,508	$ -	$ -	$ -	$ -	$ 1,508
N/A	2055	Construction in Progress - Underground	N/A	N/A	$ 1,415	$ 531	$ -	$ 1,946	$ -	$ -	$ -	$ -	$ 1,946
N/A	2055	Construction in Progress - Comp Hardware (CIS)	N/A	N/A	$ 2,227	$ (788)	$ -	$ 1,439	$ -	$ -	$ -	$ -	$ 1,439
N/A	1555	Construction in Progress - Comp Software SM	N/A	N/A	$ -	$ 15	$ -	$ 15	$ -	$ -	$ -	$ -	$ 15
N/A	2055	Construction in Progress - Comp Software	N/A	N/A	$ 1,123	$ 7,221	$ -	$ 8,345	$ -	$ -	$ -	$ -	$ 8,345
		Total			**$ 766,280**	**$ 51,503**	**$ (14,039)**	**$ 803,744**	**$ (352,393)**	**$ (33,847)**	**$ 11,780**	**$ (374,460)**	**$ 429,284**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] 2009 CGAAP

			Cost				Accumulated Depreciation				
Description	**Useful life**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Disposals /Retirements**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals /Retirements**	**Closing Balance**	**Net Book Value**
Land	N/A	N/A	$ 4,070	$ -	$ -	$ 4,070	$ -	$ -	$ -	$ -	$ 4,070
Buildings and Fixtures	50-60	1.67%-2%	$ 13,915	$ 205	$ -	$ 14,120	$ (4,920)	$ (249)	$ -	$ (5,169)	$ 8,952
Buildings and Fixtures (Improvements)	25	4.00%	$ 2,698	$ 294	$ -	$ 2,992	$ (461)	$ (114)	$ -	$ (575)	$ 2,418
Distribution Station Equipment <50 kV	30	3.33%	$ 70,462	$ 7,972	$ (2,216)	$ 76,218	$ (27,798)	$ (2,464)	$ 2,216	$ (28,046)	$ 48,172
Poles, Towers & Fixtures	25	4.00%	$ 171,975	$ 10,126	$ (1,955)	$ 180,146	$ (67,236)	$ (7,080)	$ 1,850	$ (72,467)	$ 107,679
Underground Conduit	25	4.00%	$ 442,904	$ 13,772	$ (1,149)	$ 455,527	$ (200,784)	$ (17,781)	$ 1,149	$ (217,416)	$ 238,110
Line Transformers	25	4.00%	$ 68,124	$ 386	$ (1,285)	$ 67,225	$ (44,446)	$ (2,660)	$ 1,285	$ (45,821)	$ 21,404
Meters	25-35	2.86%-4.00%	$ 32,070	$ 957	$ (3,828)	$ 29,200	$ (19,022)	$ (1,125)	$ 291	$ (19,855)	$ 9,345
Meters (Smart Meters New Condos)	15	6.67%	$ 1,253	$ 1,035	$ -	$ 2,288	$ (47)	$ (118)	$ -	$ (166)	$ 2,123
Meters (Smart Meters)	15	6.67%	$ 13,236	$ 7,502	$ ()	$ 20,738	$ (950)	$ (1,132)	$	$ (2,082)	$ 18,656
Computer Equip - Smart Meters	5	20.00%	$ 795	$ 104	$ -	$ 899	$ (237)	$ (146)	$ -	$ (384)	$ 515
Computer Software (Smart Meters)	5	20.00%	$ -	$ 768	$ -	$ 768	$ -	$ (38)	$ -	$ (38)	$ 730
General Equipment & Office Furniture	10	10.00%	$ 5,774	$ 1,244	$ (155)	$ 6,863	$ (2,187)	$ (632)	$ 155	$ (2,664)	$ 4,199
Computer Equip.-Hardware	5	20.00%	$ 4,710	$ 2,281	$ (1,237)	$ 5,753	$ (2,556)	$ (1,055)	$ 1,237	$ (2,374)	$ 3,380
Computer Software	10	10.00%	$ 2,744	$ 11,858	$ -	$ 14,602	$ (1,118)	$ (792)	$ -	$ (1,910)	$ 12,692
Computer Software	2	50.00%	$ 818	$ 395	$ (112)	$ 1,101	$ (366)	$ (394)	$ 112	$ (648)	$ 453
Transportation Equipment (4 years)	4	25.00%	$ 454	$	$ (67)	$ 387	$ (152)	$ (104)	$ 44	$ (211)	$ 175
Transportation Equipment (5 years)	5	20.00%	$ 2,558	$ 78	$ (481)	$ 2,154	$ (1,590)	$ (378)	$ 451	$ (1,518)	$ 637
Transportation Equipment (8 years)	8	12.50%	$ 12,197	$ 1,872	$ (1,593)	$ 12,476	$ (8,006)	$ (996)	$ 1,588	$ (7,415)	$ 5,062
Tools, Shop & Garage Equipment	10	10.00%	$ 1,597	$ 262	$ (93)	$ 1,766	$ (655)	$ (168)	$ 93	$ (731)	$ 1,035
System Supervisor Equipment	15-25	4%-6.67%	$ 14,224	$ 2,222	$ (365)	$ 16,081	$ (6,889)	$ (903)	$ 365	$ (7,427)	$ 8,654
Contributions & Grants - Overhead	25	4.00%	$ (7,922)	$ (976)	$ -	$ (8,898)	$ 1,169	$ 336	$ -	$ 1,505	$ (7,393)
Contributions & Grants - Transformers	25	4.00%	$ (8,604)	$ 4,307	$ -	$ (4,297)	$ 1,892	$ 258	$ -	$ 2,150	$ (2,147)
Contributions & Grants - Underground	25	4.00%	$ (61,547)	$ 3,068	$ -	$ (58,479)	$ 11,902	$ 2,401	$ -	$ 14,302	$ (44,177)
Construction in Progress - CIAC	N/A	N/A	$ (346)	$ (122)	$ -	$ (467)	$ -	$ -	$ -	$ -	$ (467)
Construction in Progress - Substation Equip	N/A	N/A	$ 1,633	$ (702)	$ -	$ 931	$ -	$ -	$ -	$ -	$ 931
Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 698	$ (692)	$ -	$ 6	$ -	$ -	$ -	$ -	$ 6
Construction in Progress - Overhead	N/A	N/A	$ 1,508	$ 388	$ -	$ 1,897	$ -	$ -	$ -	$ -	$ 1,897
Construction in Progress - Underground	N/A	N/A	$ 1,946	$ (11)	$ -	$ 1,935	$ -	$ -	$ -	$ -	$ 1,935
Construction in Progress - Comp Hardware (C	N/A	N/A	$ 1,439	$ (1,439)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Construction in Progress - Comp Software SM	N/A	N/A	$ 15	$ -		$ 15				$ -	$ 15
Construction in Progress - Comp Software	N/A	N/A	$ 8,345	$ (7,814)	$ -	$ 531	$ -	$ -	$ -	$ -	$ 531
Total			**$ 803,744**	**$ 59,342**	**$ (14,537)**	**$ 848,548**	**$ (374,460)**	**$ (35,335)**	**$ 10,838**	**$ (398,957)**	**$ 449,591**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2010 CGAAP**

			Cost					Accumulated Depreciation					
Description	**Useful life**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Transfers**	**Disposals /Retirements**	**Closing Balance**	**Opening Balance**	**Additions**	**Transfers**	**Disposals /Retirements**	**Closing Balance**	**Net Book Value**
Land	N/A	N/A	$ 4,070	$ -	$ -	$ -	$ 4,070	$ -	$ -	$ -	$ -	$ -	$ 4,070
Land Rights /Easements	N/A	N/A	$ -	$ 36	$ -	$ -	$ 36	$ -	$ -	$ -	$ -	$ -	$ 36
Buildings and Fixtures	50-60	1.67%-2%	$ 14,120	$ 352	$ (347)	$ -	$ 14,126	$ (5,169)	$ (248)	$ 89	$ -	$ (5,328)	$ 8,798
Buildings and Fixtures (Improvements)	25	4.00%	$ 2,992	$ 1,134	$ 347	$ -	$ 4,473	$ (575)	$ (156)	$ (89)	$ -	$ (820)	$ 3,653
Distribution Station Equipment <50 kV	30	3.33%	$ 76,218	$ 3,875	$ -	$ (235)	$ 79,857	$ (28,046)	$ (2,593)	$ -	$ 235	$ (30,403)	$ 49,454
Poles, Towers & Fixtures	25	4.00%	$ 180,146	$ 12,631	$ -	$ (2,045)	$ 190,732	$ (72,467)	$ (7,458)	$ -	$ 2,045	$ (77,880)	$ 112,851
Underground Conduit	25	4.00%	$ 455,527	$ 26,734	$ -	$ 1,828	$ 484,089	$ (217,416)	$ (18,592)	$ -	$ (1,828)	$ (237,836)	$ 246,253
Line Transformers	25	4.00%	$ 67,225	$ 33	$ -	$ (3,819)	$ 63,439	$ (45,821)	$ (2,625)	$ -	$ 3,819	$ (44,627)	$ 18,812
Meters	25-35	2.86%-4.00%	$ 29,200	$ 874	$ -	$ (4,011)	$ 26,062	$ (19,855)	$ (1,092)	$ -	$ 977	$ (19,970)	$ 6,092
Meters (Smart Meters New Condos)	15	6.67%	$ 2,288	$ 970	$ -	$ -	$ 3,258	$ (166)	$ (185)	$ -	$ -	$ (350)	$ 2,908
Green Energy - FIT/Micro	15	6.67%	$ -	$ 23	$ -	$ -	$ 23	$ -	$ (1)	$ -	$ -	$ (1)	$ 22
Meters (Smart Meters)	15	6.67%	$ 20,738	$ 6,275	$ -	$ -	$ 27,013	$ (2,082)	$ (1,592)	$ -	$ -	$ (3,674)	$ 23,339
Meters (Smart Meters Hazardous Meters)	15	6.67%	$ -	$ 942	$ -	$ -	$ 942	$ -	$ (31)	$ -	$ -	$ (31)	$ 910
Computer Equip - Meters (Smart Meters)	5	20.00%	$ 899	$	$ -	$ -	$ 899	$ (384)	$ (157)	$ -	$ -	$ (540)	$ 358
Computer Software (Smart Meters)	5	20.00%	$ 768	$ 65	$ -	$ -	$ 833	$ (38)	$ (80)	$ -	$ -	$ (119)	$ 715
General Equipment & Office Furniture	10	10.00%	$ 6,863	$ 182	$ -	$ (152)	$ 6,893	$ (2,664)	$ (688)	$ -	$ 152	$ (3,200)	$ 3,693
Computer Equip.-Hardware(Post Mar. 19/07)	5	20.00%	$ 5,753	$ 1,079	$ -	$ (582)	$ 6,250	$ (2,374)	$ (1,209)	$ -	$ 582	$ (3,000)	$ 3,250
Computer Software	10	10.00%	$ 14,602	$ 1,136	$ -	$ (1,019)	$ 14,719	$ (1,910)	$ (1,425)	$ -	$ 1,019	$ (2,317)	$ 12,403
Computer Software	2	50.00%	$ 1,101	$ 100	$ -	$ (706)	$ 494	$ (648)	$ (380)	$ -	$ 706	$ (321)	$ 173
Computer Software	5	20.00%	$ -	$ 502	$ -	$ -	$ 502	$ -	$ (50)	$ -	$ -	$ (50)	$ 452
Transportation Equipment (4 years)	4	25.00%	$ 387	$ 103	$ -	$ (96)	$ 393	$ (211)	$ (87)	$ -	$ 80	$ (218)	$ 175
Transportation Equipment (5 years)	5	20.00%	$ 2,154	$ 92	$ -	$ (80)	$ 2,166	$ (1,518)	$ (282)	$ -	$ 80	$ (1,720)	$ 446
Transportation Equipment (8 years)	8	12.50%	$ 12,476	$ 1,218	$ (8)	$ (1,230)	$ 12,457	$ (7,415)	$ (1,083)	$	$ 1,230	$ (7,267)	$ 5,189
Tools, Shop & Garage Equipment	10	10.00%	$ 1,766	$ 88	$ 8	$ (84)	$ 1,777	$ (731)	$ (178)	$ ()	$ 84	$ (824)	$ 953
System Supervisor Equipment	15-25	4%-6.67%	$ 16,081	$ 1,083	$ -	$ (115)	$ 17,048	$ (7,427)	$ (991)	$ -	$ 115	$ (8,303)	$ 8,746
Contributions & Grants - Overhead	25	4.00%	$ (8,898)	$ (1,233)	$ -	$ -	$ (10,131)	$ 1,505	$ 381	$ -	$ -	$ 1,886	$ (8,245)
Contributions & Grants - Transformers	25	4.00%	$ (4,297)	$ (33)	$ -	$ -	$ (4,330)	$ 2,150	$ 173	$ -	$ -	$ 2,323	$ (2,007)
Contributions & Grants - Underground	25	4.00%	$ (58,479)	$ (8,784)	$ -	$ -	$ (67,264)	$ 14,302	$ 2,515	$ -	$ -	$ 16,817	$ (50,446)
Construction in Progress - CIAC	N/A	N/A	$ (467)	$ 1,566	$ -	$ -	$ 1,099	$ -	$ -	$ -	$ -	$ -	$ 1,099
Construction in Progress - Substation Equip	N/A	N/A	$ 931	$ (457)	$ -	$ -	$ 474	$ -	$ -	$ -	$ -	$ -	$ 474
Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 6	$ 233	$ -	$ -	$ 239	$ -	$ -	$ -	$ -	$ -	$ 239
Construction in Progress - Overhead	N/A	N/A	$ 1,897	$ (527)	$ -	$ -	$ 1,370	$ -	$ -	$ -	$ -	$ -	$ 1,370
Construction in Progress - Underground	N/A	N/A	$ 1,935	$ 1,153	$ -	$ -	$ 3,089	$ -	$ -	$ -	$ -	$ -	$ 3,089
Construction in Progress - Building Brick	N/A	N/A	$ -	$ 287	$ -	$ -	$ 287	$ -	$ -	$ -	$ -	$ -	$ 287
Construction in Progress - Green Energy	N/A	N/A	$ -	$ 38	$ -	$ -	$ 38	$ -	$ -	$ -	$ -	$ -	$ 38
Construction in Progress - Comp Software SM	N/A	N/A	$ 15	$ 919	$ -	$ -	$ 933	$ -	$ -	$ -	$ -	$ -	$ 933
Construction in Progress - Comp Software	N/A	N/A	$ 531	$ 340	$ -	$ -	$ 871	$ -	$ -	$ -	$ -	$ -	$ 871
Total			**$ 848,548**	**$ 53,028**	**$ -**	**$ (12,348)**	**$ 889,228**	**$ (398,957)**	**$ (38,114)**	**$ -**	**$ 9,297**	**$ (427,774)**	**$ 461,454**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] **2011 IFRS Opening Balances**

			Cost						Accumulated Depreciation					
Description	**Useful life**	**Depreciation Rate**	**2010 CGAAP Cost Closing Balance**	**Accumulated Depreciation Adjustment**	**Capital Contribution Adjustment**	**Transfers to components**	**Transfer from 1555**	**2011 IFRS Cost Opening Balance**	**2010 CGAAP ACC. Dep. Closing**	**Accumulated Depreciation Adjustment**	**Capital Contribution Adjustment**	**Transfers**	**2011 IFRS Acc. Dep Opening Balance**	**Net Book Value Opening Balance**
Land	N/A	N/A	$ 4,070	$ -	$ -	$ -		$ 4,070	$ -	$ -	$ -	$ -	$ -	$ 4,070
Land Rights /Easements	N/A	N/A	$ 36	$ -	$ -	$ -		$ 36	$ -	$ -	$ -	$ -	$ -	$ 36
Buildings and Fixtures	60	1.67%	$ 14,126	$ (5,328)	$ -	$ -		$ 8,798	$ (5,328)	$ 5,328	$ -	$ -	$ -	$ 8,798
Buildings and Fixtures (Improvements)	20	5.00%	$ 4,473	$ (820)	$ -	$ -		$ 3,653	$ (820)	$ 820	$ -	$ -	$ -	$ 3,653
Distribution Station Equipment <50 kV	40	2.50%	$ 79,857	$ (30,403)	$ -	$ -		$ 49,454	$ (30,403)	$ 30,403	$ -	$ -	$ -	$ 49,454
System Supervisor Equipment	15-25	4%-6.67%	$ 17,048	$ (8,303)	$ -	$ (8,746)		$ -	$ (8,303)	$ 8,303	$ -	$ -	$ -	$ -
System Supervisor Equipment (Scadamate/Reclosur	25	4.00%	$ -	$ -	$ -	$ 6,435		$ 6,435		$ -	$ -	$ -	$ -	$ 6,435
System Supervisor Equipment (Scada/Pro & DC Sys	15	6.67%	$ -	$ -	$ -	$ 4,424		$ 4,424		$ -	$ -	$ -	$ -	$ 4,424
Poles, Towers & Fixtures	25	4.00%	$ 190,732	$ (77,880)	$ (8,245)	$ (104,606)		$ -	$ (77,880)	$ 77,880	$ -	$ -	$ -	$ -
O/H Wood Pole Systems	45	2.22%	$ -	$ -	$ -	$ 25,838		$ 25,838		$ -	$ -	$ -	$ -	$ 25,838
O/H Concrete Pole Syst	55	1.82%	$ -	$ -	$ -	$ 54,102		$ 54,102		$ -	$ -	$ -	$ -	$ 54,102
Line Transformers (O/H Transformer System)	45	2.22%	$ -	$ -	$ -	$ 9,000		$ 9,000		$ -	$ -	$ -	$ -	$ 9,000
O/H Switches/Fuses	40	2.50%	$ -	$ -	$ -	$ 13,954		$ 13,954		$ -	$ -	$ -	$ -	$ 13,954
O/H Fault Indicators	10	10.00%	$ -	$ -	$ -	$ 460		$ 460		$ -	$ -	$ -	$ -	$ 460
Underground Conduit	25	4.00%	$ 484,089	$ (237,836)	$ (50,446)	$ (195,807)		$ -	$ (237,836)	$ 237,836	$ -	$ -	$ -	$ -
Underground Cable	40	2.50%	$ -	$ -	$ -	$ 128,912		$ 128,912		$ -	$ -	$ -	$ -	$ 128,912
Line Transformers (PadMounted Transformers)	35	2.86%	$ -	$ -	$ -	$ 41,308		$ 41,308		$ -	$ -	$ -	$ -	$ 41,308
Duct & Foundations	50	2.00%	$ -	$ -	$ -	$ 31,262		$ 31,262		$ -	$ -	$ -	$ -	$ 31,262
Underground Accessories	20	5.00%	$ -	$ -	$ -	$ 7,944		$ 7,944		$ -	$ -	$ -	$ -	$ 7,944
Air Insulated Switchgear	25	4.00%	$ -	$ -	$ -	$ 2,064		$ 2,064		$ -	$ -	$ -	$ -	$ 2,064
Solid Dielectric Switchgear	35	2.86%	$ -	$ -	$ -	$ 260		$ 260		$ -	$ -	$ -	$ -	$ 260
Line Transformers	25	4.00%	$ 63,439	$ (44,627)	$ (2,007)	$ (16,805)		$ -	$ (44,627)	$ 44,627	$ -	$ -	$ -	$ -
Wholesale Meters	25	4.00%	$ -	$ -	$ -	$ 2,582		$ 2,582		$ -	$ -	$ -	$ -	$ 2,582
Meters	25-35	2.86%-4.00%	$ 26,062	$ (19,970)	$ -	$ (6,092)		$ -	$ (19,970)	$ 19,970	$ -	$ -	$ -	$ -
Other Conventional Meters	25	4.00%	$ -	$ -	$ -	$ 3,510	$ 2,873	$ 6,383		$ -	$ -	$ -	$ -	$ 6,383
Meters (Smart Meters New Condos)	15	6.67%	$ 3,258	$ (350)	$ -			$ 2,908	$ (350)	$ 350	$ -	$ -	$ -	$ 2,908
Green Energy - FIT/Micro	15	6.67%	$ 23	$ (1)	$ -			$ 22	$ (1)	$ 1	$ -	$ -	$ -	$ 22
Meters (Smart Meters)	15	6.67%	$ 27,013	$ (3,674)	$ -			$ 23,339	$ (3,674)	$ 3,674	$ -	$ -	$ -	$ 23,339
Meters (Smart Meters Hazardous Meters)	15	6.67%	$ 942	$ (31)	$ -			$ 910	$ (31)	$ 31	$ -	$ -	$ -	$ 910
Computer Equip - Meters (Smart Meters)	5	20.00%	$ 899	$ (540)	$ -			$ 358	$ (540)	$ 540	$ -	$ -	$ -	$ 358
General Equipment & Office Furniture	10	10.00%	$ 6,893	$ (3,200)	$ -	$ 6		$ 3,699	$ (3,200)	$ 3,200	$ -	$ -	$ -	$ 3,699
Transportation Equipment (4 years)	4	25.00%	$ 393	$ (218)	$ -	$ (175)		$ -	$ (218)	$ 218	$ -	$ -	$ -	$ -
Transportation Equipment (5 years)	5	20.00%	$ 2,166	$ (1,720)	$ -	$ (446)		$ -	$ (1,720)	$ 1,720	$ -	$ -	$ -	$ -
Transportation Equipment (8 years)	8	12.50%	$ 12,457	$ (7,267)	$ -	$ (5,189)		$ -	$ (7,267)	$ 7,267	$ -	$ -	$ -	$ -
Transportation Equipment (Cars and Supervisor Veh	4	25.00%	$ -	$ -	$ -	$ 206		$ 206		$ -	$ -	$ -	$ -	$ 206
Transportation Equipment (Double Bucket & RBDs)	12	8.33%	$ -	$ -	$ -	$ 1,573		$ 1,573		$ -	$ -	$ -	$ -	$ 1,573
Transportation Equipment (Single Buckets, Dump tru	8	12.50%	$ -	$ -	$ -	$ 3,074		$ 3,074		$ -	$ -	$ -	$ -	$ 3,074
Transportation Equipment (Trailers)	15	6.67%	$ -	$ -	$ -	$ 582		$ 582		$ -	$ -	$ -	$ -	$ 582
Transportation Equipment (Trucks & Vans)	5	20.00%	$ -	$ -	$ -	$ 375		$ 375		$ -	$ -	$ -	$ -	$ 375
Major Tools	10	10.00%	$ 1,777	$ (824)	$ -	$ (6)		$ 947	$ (824)	$ 824	$ -	$ -	$ -	$ 947
Computer Equip.-Hardware(Post Mar. 19/07)	5	20.00%	$ 6,250	$ (3,000)	$ -	$ (3,250)		$ -	$ (3,000)	$ 3,000	$ -	$ -	$ -	$ -
Computer Equipment - Hardware (Desktop)	3	33.33%		$ -	$ -	$ 431		$ 431		$ -	$ -	$ -	$ -	$ 431
Computer Equipment - Hardware (Network)	5	20.00%		$ -	$ -	$ 2,597		$ 2,597		$ -	$ -	$ -	$ -	$ 2,597
Computer Equipment - Hardware (Corporate)	10	10.00%		$ -	$ -	$ 221		$ 221		$ -	$ -	$ -	$ -	$ 221
Computer Software (10 year)	10	10.00%	$ 14,719	$ (2,317)	$ -	$		$ 12,403	$ (2,317)	$ 2,317	$ -	$ -	$ -	$ 12,403
Computer Software (2 year)	2	50.00%	$ 494	$ (321)	$ -	$ -		$ 173	$ (321)	$ 321	$ -	$ -	$ -	$ 173
Computer Software (5 year)	5	20.00%	$ 502	$ (50)	$ -	$ -		$ 452	$ (50)	$ 50	$ -	$ -	$ -	$ 452
Computer Software (Smart Meters)	5	20.00%	$ 833	$ (119)	$ -	$ -		$ 715	$ (119)	$ 119	$ -	$ -	$ -	$ 715
Contributions & Grants - Overhead	25	4.00%	$ (10,131)	$ -	$ 10,131	$ -		$ -	$ 1,886	$ -	$ (1,886)	$ -	$ -	$ -
Contributions & Grants - Transformers	25	4.00%	$ (4,330)	$ -	$ 4,330	$ -		$ -	$ 2,323	$ -	$ (2,323)	$ -	$ -	$ -
Contributions & Grants - Underground	25	4.00%	$ (67,264)	$ -	$ 67,264	$ -		$ -	$ 16,817	$ -	$ (16,817)	$ -	$ -	$ -
Construction in Progress - CIAC	N/A	N/A	$ 1,099	$ -	$ (1,099)	`		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Construction in Progress - Substation Equip	N/A	N/A	$ 474	$ -	$ -	$ -		$ 474	$ -	$ -	$ -	$ -	$ -	$ 474
Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 239	$ -	$ -	$ -		$ 239	$ -	$ -	$ -	$ -	$ -	$ 239
Construction in Progress - Overhead	N/A	N/A	$ 1,370	$ -	$ (35)	$ -		$ 1,335	$ -	$ -	$ -	$ -	$ -	$ 1,335
Construction in Progress - Underground	N/A	N/A	$ 3,089	$ -	$ 1,134	$ -		$ 4,223	$ -	$ -	$ -	$ -	$ -	$ 4,223
Construction in Progress - Building Brick	N/A	N/A	$ 287	$ -	$ -	$ -		$ 287	$ -	$ -	$ -	$ -	$ -	$ 287
Construction in Progress - Green Energy	N/A	N/A	$ 38	$ -	$ -	$ -		$ 38	$ -	$ -	$ -	$ -	$ -	$ 38
Construction in Progress - Comp Software SM	N/A	N/A	$ 933	$ -	$ -			$ 933	$ -	$ -	$ -	$ -	$ -	$ 933
Construction in Progress - Comp Software	N/A	N/A	$ 871	$ -	$ -			$ 871	$ -	$ -	$ -	$ -	$ -	$ 871
Total			**$ 889,228**	**$ (448,800)**	**$ 21,026**	**$ -**	**$ 2,873**	**$ 464,327**	**$ (427,774)**	**$ 448,800**	**$ (21,026)**	**$ -**	**$ -**	**$ 464,327**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] 2011 IFRS

			Cost							Accumulated Depreciation						
Description	**Useful life**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Transfers**	**Transformation write off**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Opening Balance**	**Additions**	**Transfers**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Net Book Value**
Land	N/A	N/A	$ 4,070	$ -			$ -	$ (1)	$ 4,069	$ -	$ -		$ -	$ -	$ -	$ 4,069
Land Rights /Easements	N/A	N/A	$ 36	$ 297			$ -	$ -	$ 332	$ -	$ -		$ -	$ -	$ -	$ 332
Buildings and Fixtures	60	1.67%	$ 8,798	$ 521			$ -	$ ()	$ 9,319	$ -	$ (221)		$ -	$	$ (221)	$ 9,097
Buildings and Fixtures (Improvements)	20	5.00%	$ 3,653	$ 1,850			$ -	$ -	$ 5,503	$ -	$ (310)		$ -	$ -	$ (310)	$ 5,193
Distribution Station Equipment <50 kV	40	2.50%	$ 49,454	$ 4,715			$ (98)	$ -	$ 54,071	$ -	$ (1,689)		$ 5	$ -	$ (1,684)	$ 52,387
Wholesale Meters	25	4.00%	$ -	$ -	$ 3,281				$ 3,281		$ -	$ (131)			$ (131)	$ 3,151
System Supervisor Equipment (Scadamate/Reclosur	25	4.00%	$ 6,435	$ 117		$ ()	$ -	$ -	$ 6,551	$ -	$ (405)		$ -	$ -	$ (405)	$ 6,146
System Supervisor Equipment (Scada/Pro & DC Sys	15	6.67%	$ 4,424	$ 1,160		$ (448)	$ -	$ (50)	$ 5,086	$ -	$ (564)		$ -	$ 50	$ (514)	$ 4,571
O/H Wood Pole Systems	45	2.22%	$ 25,838	$ 1,014			$ (188)	$ -	$ 26,664	$ -	$ (712)		$ 4	$ -	$ (708)	$ 25,956
O/H Concrete Pole Syst	55	1.82%	$ 54,102	$ 5,551			$ (102)	$ -	$ 59,552	$ -	$ (1,201)		$ 2	$ -	$ (1,198)	$ 58,353
O/H Transformer System	45	2.22%	$ 9,000	$ 1,218			$ (61)	$ -	$ 10,157	$ -	$ (269)		$ 2	$ -	$ (268)	$ 9,889
O/H Switches/Fuses	40	2.50%	$ 13,954	$ 1,384			$ (293)	$ -	$ 15,045	$ -	$ (457)		$ 7	$ -	$ (449)	$ 14,596
O/H Fault Indicators	10	10.00%	$ 460	$ 82		$ (137)	$ -	$ (23)	$ 383	$ -	$ (92)		$ -	$ 23	$ (70)	$ 313
Underground Cable	40	2.50%	$ 128,912	$ 12,623			$ (733)	$ -	$ 140,801	$ -	$ (4,909)		$ 24	$ -	$ (4,884)	$ 135,917
PadMounted Transformers	35	2.86%	$ 41,308	$ 2,254		$ (9)	$ (414)	$ -	$ 43,138	$ -	$ (2,079)		$ 19	$ -	$ (2,060)	$ 41,077
Duct & Foundations	50	2.00%	$ 31,262	$ 3,074			$ -	$ -	$ 34,336	$ -	$ (845)		$ -	$ -	$ (845)	$ 33,491
Underground Accessories	20	5.00%	$ 7,944	$ 492		$ (589)	$ (11)	$ (218)	$ 7,618	$ -	$ (1,212)		$ 1	$ 218	$ (993)	$ 6,625
Air Insulated Switchgear	25	4.00%	$ 2,064	$ 225		$ (72)	$ (26)	$ -	$ 2,191	$ -	$ (185)		$ 2	$ -	$ (183)	$ 2,008
Solid Dielectric Switchgear	35	2.86%	$ 260	$ 359			$ -	$ -	$ 619	$ -	$ (13)		$ -	$ -	$ (13)	$ 606
Other Conventional Meters	25	4.00%	$ 6,383	$ 449			$ -	$ (933)	$ 5,899	$ -	$ (297)		$ -	$ 25	$ (272)	$ 5,627
Wholesale Meters	25	4.00%	$ 2,582	$ 700	$ (3,281)		$ -	$ -	$ -	$ -	$ (131)	$ 131	$ -	$ -	$ -	$ -
Meters (Smart Meters - New)	15	6.67%	$ -	$ 177			$ -	$ -	$ 177	$ -	$ (6)		$ -	$ -	$ (6)	$ 171
Meters (Smart Meters New Condos)	15	6.67%	$ 2,908	$ 681			$ -	$ -	$ 3,589	$ -	$ (240)		$ -	$ -	$ (240)	$ 3,348
Green Energy - FIT/Micro	15	6.67%	$ 22	$ 88			$ -	$ -	$ 111	$ -	$ (4)		$ -	$ -	$ (4)	$ 106
Meters (Smart Meters)	15	6.67%	$ 23,339	$ 1,710			$ -	$ -	$ 25,049	$ -	$ (1,857)		$ -	$ -	$ (1,857)	$ 23,192
Meters (Smart Meters Hazardous Meters)	15	6.67%	$ 910	$ 65			$ -	$ -	$ 976	$ -	$ (65)		$ -	$ -	$ (65)	$ 911
Computer Equip - Meters (Smart Meters)	5	20.00%	$ 358	$ -			$ -	$ (4)	$ 355	$ -	$ (153)		$ -	$ 4	$ (149)	$ 206
Computer Software (Smart Meters)	5	20.00%	$ 715	$ 2,062			$ -	$ -	$ 2,776	$ -	$ (290)		$ -	$ -	$ (290)	$ 2,486
General Equipment & Office Furniture	10	10.00%	$ 3,699	$ 221			$ -	$ (21)	$ 3,899	$ -	$ (680)		$ -	$ 21	$ (659)	$ 3,240
Transportation Equipment (Cars and Supervisor Veh	4	25.00%	$ 206	$ 266				$ (114)	$ 357	$ -	$ (106)		$ -	$ 36	$ (70)	$ 287
Transportation Equipment (Double Bucket & RBDs)	12	8.33%	$ 1,573	$ 937			$ -	$ -	$ 2,510	$ -	$ (227)		$ -	$ -	$ (227)	$ 2,283
Transportation Equipment (Single Buckets, Dump tru	8	12.50%	$ 3,074	$ 410			$ -	$ (6)	$ 3,478	$ -	$ (701)		$ -	$ 1	$ (700)	$ 2,778
Transportation Equipment (Trailers)	15	6.67%	$ 582	$ 127			$ -	$ -	$ 709	$ -	$ (55)		$ -	$ -	$ (55)	$ 655
Transportation Equipment (Trucks & Vans)	5	20.00%	$ 375	$ 52				$	$ 428	$ -	$ (198)		$ -	$ -	$ (198)	$ 230
Major Tools	10	10.00%	$ 947	$ 278			$ -	$ (7)	$ 1,218	$ -	$ (184)		$ -	$ 7	$ (177)	$ 1,041
Computer Equipment - Hardware (Desktop)	3	33.33%	$ 431	$ 321		$ (58)	$ -	$ (160)	$ 534	$ -	$ (356)		$ -	$ 160	$ (196)	$ 338
Computer Equipment - Hardware (Network)	5	20.00%	$ 2,597	$ 1,202			$ -	$ (83)	$ 3,717	$ -	$ (896)		$ -	$ 83	$ (813)	$ 2,904
Computer Equipment - Hardware (Corporate)	10	10.00%	$ 221	$ 4			$ -	$ -	$ 226	$ -	$ (35)		$ -	$ -	$ (35)	$ 190
Computer Software (10 year)	10	10.00%	$ 12,403	$ 3,640			$ -	$ -	$ 16,043	$ -	$ (1,706)		$ -	$ -	$ (1,706)	$ 14,337
Computer Software (2 year)	2	50.00%	$ 173	$ 24			$ -	$ (99)	$ 99	$ -	$ (155)		$ -	$ 99	$ (56)	$ 43
Computer Software (5 year)	5	20.00%	$ 452	$ 347			$ -	$ -	$ 799	$ -	$ (135)		$ -	$ -	$ (135)	$ 665
Contributions & Grants - Wood Poles	45	2.22%	$ -	$ (42)				$ -	$ (42)	$ -	$		$ -	$ -	$	$ (42)
Contributions & Grants - Concrete Poles	55	1.82%	$ -	$ (1,259)				$ -	$ (1,259)	$ -	$ 11		$ -	$ -	$ 11	$ (1,248)
Contributions & Grants - OH TX	45	2.22%	$ -	$ (189)				$ -	$ (189)	$ -	$ 2		$ -	$ -	$ 2	$ (187)
Contributions & Grants - OH Switches	40	2.50%	$ -	$ (147)				$ -	$ (147)	$ -	$ 2		$ -	$ -	$ 2	$ (145)
Contributions & Grants - UG Cable	40	2.50%	$ -	$ (1,883)				$ -	$ (1,883)	$ -	$ 24		$ -	$ -	$ 24	$ (1,859)
Contributions & Grants - Padmounted TX	35	2.86%	$ -	$ (146)				$ -	$ (146)	$ -	$ 2		$ -	$ -	$ 2	$ (144)
Contributions & Grants - Duct & Foundation	50	2.00%	$ -	$ (528)				$ -	$ (528)	$ -	$ 5		$ -	$ -	$ 5	$ (523)
Contributions & Grants - UG Accessories	20	5.00%	$ -	$ (158)				$ -	$ (158)	$ -	$ 4		$ -	$ -	$ 4	$ (154)
Construction in Progress - CIAC	N/A	N/A		$ (145)				$ -	$ (145)		$ -		$ -		$ -	$ (145)
Construction in Progress - Substation Equip	N/A	N/A	$ 474	$ (410)				$ -	$ 64	$ -	$ -		$ -	$ -	$ -	$ 64
Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 239	$ 214				$ -	$ 453	$ -	$ -		$ -	$ -	$ -	$ 453
Construction in Progress - Overhead	N/A	N/A	$ 1,335	$ (118)				$ -	$ 1,217	$ -	$ -		$ -	$ -	$ -	$ 1,217
Construction in Progress - Underground	N/A	N/A	$ 4,223	$ (2,042)				$ -	$ 2,181	$ -	$ -		$ -	$ -	$ -	$ 2,181
Construction in Progress - Building Brick	N/A	N/A	$ 287	$ (201)				$ -	$ 87	$ -	$ -		$ -	$ -	$ -	$ 87
Construction in Progress - Rolling Stock	N/A	N/A	$ -	$ 90				$ -	$ 90	$ -	$ -		$ -	$ -	$ -	$ 90
Construction in Progress - Green Energy	N/A	N/A	$ 38	$ 109				$ -	$ 147	$ -	$ -		$ -	$ -	$ -	$ 147
Construction in Progress - Comp Software SM	N/A	N/A	$ 933	$ (932)				$ -	$ 1	$ -	$ -		$ -	$ -	$ -	$ 1
Construction in Progress - Comp Software	N/A	N/A	$ 871	$ (346)				$ -	$ 525	$ -	$ -		$ -	$ -	$ -	$ 525
									$ -						$ -	
Total			**$ 464,327**	**$ 42,563**	**$ -**	**$ (1,313)**	**$ (1,926)**	**$ (1,719)**	**$ 501,932**	**$ -**	**$ (23,589)**	**$ -**	**$ 67**	**$ 725**	**$ (22,797)**	**$ 479,135**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] 2012 IFRS

			Cost					Accumulated Depreciation					
Description	**Useful life**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Opening Balance**	**Additions**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Net Book Value**
Land	N/A	N/A	$ 4,069	$ 5,000	$ -	$ -	$ 9,069	$ -	$ -	$ -	$ -	$ -	$ 9,069
Land Rights /Easements	N/A	N/A	$ 332	$ -	$ -	$ -	$ 332	$ -	$ -	$ -	$ -	$ -	$ 332
Buildings and Fixtures	60	1.67%	$ 9,319	$ 10,252	$ -	$ -	$ 19,571	$ (221)	$ (311)	$ -	$ -	$ (532)	$ 19,039
Buildings and Fixtures (Improvements)	20	5.00%	$ 5,503	$ 7,088	$ -	$ -	$ 12,592	$ (310)	$ (623)	$ -	$ -	$ (933)	$ 11,659
Distribution Station Equipment <50 kV	40	2.50%	$ 54,071	$ 3,736	$ (101)	$ -	$ 57,706	$ (1,684)	$ (1,793)	$ 4	$ -	$ (3,473)	$ 54,234
Wholesale Meters	25	4.00%	$ 3,281	$ 2,779	$ -	$ -	$ 6,061	$ (131)	$ (200)	$ -	$ -	$ (331)	$ 5,729
System Supervisor Equipment (Scadamate/Re	25	4.00%	$ 6,551	$ 447	$ (15)	$ (1)	$ 6,982	$ (405)	$ (416)	$ 1	$ 1	$ (818)	$ 6,163
System Supervisor Equipment (Scada/Pro & D	15	6.67%	$ 5,086	$ 998	$ -	$ (80)	$ 6,003	$ (514)	$ (559)	$ -	$ 80	$ (993)	$ 5,010
O/H Wood Pole Systems	45	2.22%	$ 26,664	$ 1,620	$ (193)	$ -	$ 28,091	$ (708)	$ (742)	$ 8	$ -	$ (1,443)	$ 26,649
O/H Concrete Pole Syst	55	1.82%	$ 59,552	$ 4,696	$ (105)	$ -	$ 64,143	$ (1,198)	$ (1,294)	$ 4	$ -	$ (2,488)	$ 61,655
O/H Transformer System	45	2.22%	$ 10,157	$ 893	$ (63)	$ -	$ 10,986	$ (268)	$ (293)	$ 3	$ -	$ (558)	$ 10,428
O/H Switches/Fuses	40	2.50%	$ 15,045	$ 1,105	$ (302)	$ -	$ 15,849	$ (449)	$ (489)	$ 12	$ -	$ (927)	$ 14,922
O/H Fault Indicators	10	10.00%	$ 383	$ 151	$ (5)	$ (26)	$ 504	$ (70)	$ (73)	$	$ 26	$ (117)	$ 387
Underground Cable	40	2.50%	$ 140,801	$ 10,372	$ (755)	$ -	$ 150,418	$ (4,884)	$ (5,198)	$ 30	$ -	$ (10,052)	$ 140,366
PadMounted Transformers	35	2.86%	$ 43,138	$ 2,274	$ (427)	$ -	$ 44,984	$ (2,060)	$ (2,148)	$ 17	$ -	$ (4,191)	$ 40,793
Duct & Foundations	50	2.00%	$ 34,336	$ 2,820	$ -	$ -	$ 37,157	$ (845)	$ (904)	$ -	$ -	$ (1,749)	$ 35,408
Underground Accessories	20	5.00%	$ 7,618	$ 448	$ (12)	$ (415)	$ 7,640	$ (993)	$ (915)	$	$ 415	$ (1,494)	$ 6,146
Air Insulated Switchgear	25	4.00%	$ 2,191	$ 34	$ (27)	$ (6)	$ 2,192	$ (183)	$ (190)	$ 1	$ 6	$ (365)	$ 1,827
Solid Dielectric Switchgear	35	2.86%	$ 619	$ 1,116	$ -	$ -	$ 1,735	$ (13)	$ (34)	$ -	$ -	$ (47)	$ 1,688
Other Conventional Meters	25	4.00%	$ 5,899	$ 446	$ -	$ (1,800)	$ 4,545	$ (272)	$ (303)	$ -	$ 500	$ (75)	$ 4,470
Meters (Smart Meters - New)	15	6.67%	$ 177	$ 494	$ -	$ -	$ 671	$ (6)	$ (28)	$ -	$ -	$ (34)	$ 637
Meters (Smart Meters New Condos)	15	6.67%	$ 3,589	$ 977	$ -	$ -	$ 4,565	$ (240)	$ (296)	$ -	$ -	$ (536)	$ 4,029
Green Energy - FIT/Micro	15	6.67%	$ 111	$ 246	$ -	$ -	$ 356	$ (4)	$ (14)	$ -	$ -	$ (19)	$ 338
Meters (Smart Meters)	15	6.67%	$ 25,049	$ 875	$ -	$ -	$ 25,924	$ (1,857)	$ (1,945)	$ -	$ -	$ (3,802)	$ 22,122
Meters (Smart Meters Hazardous Meters)	15	6.67%	$ 976	$ -	$ -	$ -	$ 976	$ (65)	$ (67)	$ -	$ -	$ (132)	$ 844
Computer Equip - Meters (Smart Meters)	5	20.00%	$ 355	$ -	$ -	$ (59)	$ 295	$ (149)	$ (129)	$ -	$ 59	$ (219)	$ 76
Computer Software (Smart Meters)	5	20.00%	$ 2,776	$ 616	$ -	$ -	$ 3,392	$ (290)	$ (558)	$ -	$ -	$ (848)	$ 2,544
General Equipment & Office Furniture	10	10.00%	$ 3,899	$ 944	$ -	$ (109)	$ 4,734	$ (659)	$ (681)	$ -	$ 109	$ (1,230)	$ 3,503
Transportation Equipment (Cars and Supervisc	4	25.00%	$ 357	$ -	$ -	$ (43)	$ 314	$ (70)	$ (114)	$ -	$ 43	$ (142)	$ 173
Transportation Equipment (Double Bucket & R	12	8.33%	$ 2,510	$ 550	$ -	$ -	$ 3,061	$ (227)	$ (287)	$ -	$ -	$ (515)	$ 2,546
Transportation Equipment (Single Buckets, Du	8	12.50%	$ 3,478	$ 293	$ -	$ (226)	$ 3,546	$ (700)	$ (683)	$ -	$ 226	$ (1,158)	$ 2,389
Transportation Equipment (Trailers)	15	6.67%	$ 709	$ -	$ -	$ -	$ 709	$ (55)	$ (54)	$ -	$ -	$ (108)	$ 601
Transportation Equipment (Trucks & Vans)	5	20.00%	$ 428	$ 868	$ -	$ (147)	$ 1,149	$ (198)	$ (205)	$ -	$ 147	$ (256)	$ 893
Major Tools	10	10.00%	$ 1,218	$ 175	$ -	$ (22)	$ 1,371	$ (177)	$ (192)	$ -	$ 22	$ (347)	$ 1,024
Computer Equipment - Hardware (Desktop)	3	33.33%	$ 534	$ 400	$ -	$ (213)	$ 721	$ (196)	$ (245)	$ -	$ 213	$ (227)	$ 494
Computer Equipment - Hardware (Network)	5	20.00%	$ 3,717	$ 923	$ -	$ (83)	$ 4,557	$ (813)	$ (998)	$ -	$ 83	$ (1,728)	$ 2,829
Computer Equipment - Hardware (Corporate)	10	10.00%	$ 226	$ 37	$ -	$ -	$ 263	$ (35)	$ (37)	$ -	$ -	$ (73)	$ 190
Computer Software (10 year)	10	10.00%	$ 16,043	$ 3,533	$ -	$ -	$ 19,576	$ (1,706)	$ (2,067)	$ -	$ -	$ (3,773)	$ 15,803
Computer Software (2 year)	2	50.00%	$ 99	$ 75	$ -	$ (75)	$ 99	$ (56)	$ (56)	$ -	$ 75	$ (37)	$ 62
Computer Software (5 year)	5	20.00%	$ 799	$ 212	$ -	$ -	$ 1,011	$ (135)	$ (77)	$ -	$ -	$ (212)	$ 799
Contributions & Grants - Wood Poles	45	2.22%	$ (42)	$ (8)	$ -	$ -	$ (51)	$	$ 1	$ -	$ -	$ 1	$ (49)
Contributions & Grants - Concrete Poles	55	1.82%	$ (1,259)	$ (520)	$ -	$ -	$ (1,779)	$ 11	$ 28	$ -	$ -	$ 39	$ (1,740)
Contributions & Grants - OH TX	45	2.22%	$ (189)	$ (211)	$ -	$ -	$ (400)	$ 2	$ 7	$ -	$ -	$ 9	$ (392)
Contributions & Grants - OH Switches	40	2.50%	$ (147)	$ (93)	$ -	$ -	$ (239)	$ 2	$ 5	$ -	$ -	$ 7	$ (233)
Contributions & Grants - UG Cable	40	2.50%	$ (1,883)	$ (1,124)	$ -	$ -	$ (3,007)	$ 24	$ 61	$ -	$ -	$ 85	$ (2,923)
Contributions & Grants - Padmounted TX	35	2.86%	$ (146)	$ (458)	$ -	$ -	$ (604)	$ 2	$ 11	$ -	$ -	$ 13	$ (591)
Contributions & Grants - Duct & Foundation	50	2.00%	$ (528)	$ (261)	$ -	$ -	$ (790)	$ 5	$ 13	$ -	$ -	$ 18	$ (771)
Contributions & Grants - UG Accessories	20	5.00%	$ (158)	$ (105)	$ -	$ -	$ (264)	$ 4	$ 21	$ -	$ -	$ 25	$ (239)
Contributions & Grants - Switchgear	35	2.86%	$ ()	$ (18)	$ -	$ -	$ (19)	$	$	$ -	$ -	$	$ (18)
Contributions & Grants - FIT/MicroFIT	15	6.67%	$ -	$ (107)	$ -	$ -	$ (107)	$ -	$ 4	$ -	$ -	$ 4	$ (103)
Construction in Progress - CIAC	N/A	N/A	$ (145)	$ -	$ -	$ -	$ (145)	$ -	$ -	$ -	$ -	$ -	$ (145)
Construction in Progress - Substation Equip	N/A	N/A	$ 64	$ -	$ -	$ -	$ 64	$ -	$ -	$ -	$ -	$ -	$ 64
Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 453	$ -	$ -	$ -	$ 453	$ -	$ -	$ -	$ -	$ -	$ 453
Construction in Progress - Overhead	N/A	N/A	$ 1,217	$ -	$ -	$ -	$ 1,217	$ -	$ -	$ -	$ -	$ -	$ 1,217
Construction in Progress - Underground	N/A	N/A	$ 2,181	$ -	$ -	$ -	$ 2,181	$ -	$ -	$ -	$ -	$ -	$ 2,181
Construction in Progress - Building Brick	N/A	N/A	$ 87	$ -	$ -	$ -	$ 87	$ -	$ -	$ -	$ -	$ -	$ 87
Construction in Progress - Rolling Stock	N/A	N/A	$ 90	$ -	$ -	$ -	$ 90	$ -	$ -	$ -	$ -	$ -	$ 90
Construction in Progress - Green Energy	N/A	N/A	$ 147	$ -	$ -	$ -	$ 147	$ -	$ -	$ -	$ -	$ -	$ 147
Construction in Progress - Comp Software SM	N/A	N/A	$ 1	$ (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Construction in Progress - Comp Software	N/A	N/A	$ 525	$ (100)	$ -	$ -	$ 425	$ -	$ -	$ -	$ -	$ -	$ 425
							$ -		$ -			$ -	
Total			**$ 501,932**	**$ 64,486**	**$ (2,004)**	**$ (3,304)**	**$ 561,110**	**$ (22,797)**	**$ (25,068)**	**$ 80**	**$ 2,005**	**$ (45,780)**	**$ 515,330**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] 2013 IFRS

			Cost					Accumulated Depreciation					
Description	**Useful life**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Opening Balance**	**Additions**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Net Book Value**
Land	N/A	N/A	$ 9,069	$ -	$ -	$ -	$ 9,069	$ -	$ -	$ -	$ -	$ -	$ 9,069
Land Rights /Easements	N/A	N/A	$ 332	$ 2,000	$ -	$ -	$ 2,332	$ -	$ -	$ -	$ -	$ -	$ 2,332
Buildings and Fixtures	60	1.67%	$ 19,571	$ 980	$ -	$ -	$ 20,551	$ (532)	$ (404)	$ -	$ -	$ (936)	$ 19,614
Buildings and Fixtures (Improvements)	20	5.00%	$ 12,592	$ 6,232	$ -	$ -	$ 18,823	$ (933)	$ (911)	$ -	$ -	$ (1,844)	$ 16,979
Distribution Station Equipment <50 kV	40	2.50%	$ 57,706	$ 3,140	$ (104)	$ -	$ 60,743	$ (3,473)	$ (1,879)	$ 4	$ -	$ (5,348)	$ 55,396
Wholesale Meters	25	4.00%	$ 6,061	$ -	$ -	$ -	$ 6,061	$ (331)	$ (256)	$ -	$ -	$ (587)	$ 5,473
System Supervisor Equipment (Scadamate/Re	25	4.00%	$ 6,982	$ 563	$ (15)	$ (1)	$ 7,528	$ (818)	$ (435)	$ 1	$ 1	$ (1,252)	$ 6,276
System Supervisor Equipment (Scada/Pro & D	15	6.67%	$ 6,003	$ 1,247	$ -	$ (51)	$ 7,200	$ (993)	$ (597)	$ -	$ 51	$ (1,540)	$ 5,660
O/H Wood Pole Systems	45	2.22%	$ 28,091	$ 1,914	$ (199)	$ -	$ 29,806	$ (1,443)	$ (782)	$ 8	$ -	$ (2,216)	$ 27,590
O/H Concrete Pole Syst	55	1.82%	$ 64,143	$ 4,535	$ (108)	$ -	$ 68,570	$ (2,488)	$ (1,378)	$ 4	$ -	$ (3,862)	$ 64,708
O/H Transformer System	45	2.22%	$ 10,986	$ 887	$ (65)	$ -	$ 11,808	$ (558)	$ (313)	$ 3	$ -	$ (868)	$ 10,940
O/H Switches/Fuses	40	2.50%	$ 15,849	$ 1,149	$ (311)	$ -	$ 16,687	$ (927)	$ (518)	$ 12	$ -	$ (1,432)	$ 15,256
O/H Fault Indicators	10	10.00%	$ 504	$ 183	$ (5)	$ (17)	$ 665	$ (117)	$ (78)	$	$ 17	$ (177)	$ 487
Underground Cable	40	2.50%	$ 150,418	$ 10,611	$ (778)	$ -	$ 160,251	$ (10,052)	$ (5,460)	$ 31	$ -	$ (15,481)	$ 144,770
PadMounted Transformers	35	2.86%	$ 44,984	$ 2,229	$ (440)	$ -	$ 46,774	$ (4,191)	$ (2,212)	$ 18	$ -	$ (6,386)	$ 40,388
Duct & Foundations	50	2.00%	$ 37,157	$ 2,779	$ -	$ -	$ 39,936	$ (1,749)	$ (960)	$ -	$ -	$ (2,709)	$ 37,227
Underground Accessories	20	5.00%	$ 7,640	$ 447	$ (12)	$ (204)	$ 7,870	$ (1,494)	$ (781)	$	$ 204	$ (2,070)	$ 5,800
Air Insulated Switchgear	25	4.00%	$ 2,192	$ 30	$ (27)	$ (15)	$ 2,180	$ (365)	$ (186)	$ 1	$ 15	$ (535)	$ 1,645
Solid Dielectric Switchgear	35	2.86%	$ 1,735	$ 1,206	$ -	$ -	$ 2,941	$ (47)	$ (67)	$ -	$ -	$ (114)	$ 2,827
Other Conventional Meters	25	4.00%	$ 4,545	$ 380	$ -	$ -	$ 4,925	$ (75)	$ (320)	$ -	$ -	$ (395)	$ 4,530
Meters (Smart Meters - New)	15	6.67%	$ 671	$ 302	$ -	$ -	$ 973	$ (34)	$ (55)	$ -	$ -	$ (89)	$ 884
Meters (Smart Meters New Condos)	15	6.67%	$ 4,565	$ 952	$ -	$ -	$ 5,517	$ (536)	$ (360)	$ -	$ -	$ (896)	$ 4,621
Green Energy - FIT/Micro	15	6.67%	$ 356	$ 322	$ -	$ -	$ 678	$ (19)	$ (33)	$ -	$ -	$ (52)	$ 627
Meters (Smart Meters)	15	6.67%	$ 25,924	$ -	$ -	$ -	$ 25,924	$ (3,802)	$ (1,974)	$ -	$ -	$ (5,776)	$ 20,148
Meters (Smart Meters Hazardous Meters)	15	6.67%	$ 976	$ -	$ -	$ -	$ 976	$ (132)	$ (67)	$ -	$ -	$ (199)	$ 777
Computer Equip - Meters (Smart Meters)	5	20.00%	$ 295	$ -	$ -	$ (220)	$ 75	$ (219)	$ (66)	$ -	$ 220	$ (64)	$ 11
Computer Software (Smart Meters)	5	20.00%	$ 3,392	$ -	$ -	$ -	$ 3,392	$ (848)	$ (619)	$ -	$ -	$ (1,468)	$ 1,924
General Equipment & Office Furniture	10	10.00%	$ 4,734	$ 1,122	$ -	$ (57)	$ 5,799	$ (1,230)	$ (736)	$ -	$ 57	$ (1,909)	$ 3,890
Transportation Equipment (Cars and Superviso	4	25.00%	$ 314	$ 289	$ -	$ (20)	$ 584	$ (142)	$ (132)	$ -	$ 20	$ (254)	$ 329
Transportation Equipment (Double Bucket & RE	12	8.33%	$ 3,061	$ 593	$ -	$ (23)	$ 3,632	$ (515)	$ (330)	$ -	$ 23	$ (822)	$ 2,809
Transportation Equipment (Single Buckets, Dur	8	12.50%	$ 3,546	$ 198	$ -	$ (201)	$ 3,543	$ (1,158)	$ (598)	$ -	$ 201	$ (1,554)	$ 1,989
Transportation Equipment (Trailers)	15	6.67%	$ 709	$ 190	$ -	$ -	$ 899	$ (108)	$ (60)	$ -	$ -	$ (169)	$ 731
Transportation Equipment (Trucks & Vans)	5	20.00%	$ 1,149	$ 573	$ -	$ (76)	$ 1,646	$ (256)	$ (285)	$ -	$ 76	$ (464)	$ 1,182
Major Tools	10	10.00%	$ 1,371	$ 200	$ -	$ (27)	$ 1,544	$ (347)	$ (198)	$ -	$ 27	$ (518)	$ 1,026
Computer Equipment - Hardware (Desktop)	3	33.33%	$ 721	$ 240	$ -	$ -	$ 961	$ (227)	$ (280)	$ -	$ -	$ (508)	$ 454
Computer Equipment - Hardware (Network)	5	20.00%	$ 4,557	$ 529	$ -	$ (91)	$ 4,995	$ (1,728)	$ (1,097)	$ -	$ 91	$ (2,734)	$ 2,261
Computer Equipment - Hardware (Corporate)	10	10.00%	$ 263	$ -	$ -	$ -	$ 263	$ (73)	$ (39)	$ -	$ -	$ (112)	$ 151
Computer Software (10 year)	10	10.00%	$ 19,576	$ 3,088	$ -	$ -	$ 22,664	$ (3,773)	$ (2,374)	$ -	$ -	$ (6,148)	$ 16,517
Computer Software (2 year)	2	50.00%	$ 99	$ 94	$ -	$ (24)	$ 169	$ (37)	$ (67)	$ -	$ 24	$ (80)	$ 89
Computer Software (5 year)	5	20.00%	$ 1,011	$ 174	$ -	$ -	$ 1,185	$ (212)	$ (116)	$ -	$ -	$ (328)	$ 857
Contributions & Grants - Wood Poles	45	2.22%	$ (51)	$ (8)	$ -	$ -	$ (59)	$ 1	$ 1	$ -	$ -	$ 3	$ (56)
Contributions & Grants - Concrete Poles	55	1.82%	$ (1,779)	$ (520)	$ -	$ -	$ (2,299)	$ 39	$ 37	$ -	$ -	$ 76	$ (2,223)
Contributions & Grants - OH TX	45	2.22%	$ (400)	$ (211)	$ -	$ -	$ (612)	$ 9	$ 11	$ -	$ -	$ 20	$ (592)
Contributions & Grants - OH Switches	40	2.50%	$ (239)	$ (93)	$ -	$ -	$ (332)	$ 7	$ 7	$ -	$ -	$ 14	$ (318)
Contributions & Grants - UG Cable	40	2.50%	$ (3,007)	$ (1,124)	$ -	$ -	$ (4,132)	$ 85	$ 89	$ -	$ -	$ 174	$ (3,958)
Contributions & Grants - Padmounted TX	35	2.86%	$ (604)	$ (458)	$ -	$ -	$ (1,062)	$ 13	$ 24	$ -	$ -	$ 37	$ (1,025)
Contributions & Grants - Duct & Foundation	50	2.00%	$ (790)	$ (261)	$ -	$ -	$ (1,051)	$ 18	$ 18	$ -	$ -	$ 37	$ (1,014)
Contributions & Grants - UG Accessories	25	4.00%	$ (264)	$ (105)	$ -	$ -	$ (369)	$ 25	$ 32	$ -	$ -	$ 57	$ (312)
Contributions & Grants - Switchgear	35	2.86%	$ (19)	$ (18)	$ -	$ -	$ (37)	$	$ 1	$ -	$ -	$ 1	$ (36)
Contributions & Grants - FIT/MicroFIT	15	6.67%	$ (107)	$ (133)	$ -	$ -	$ (240)	$ 4	$ 12	$ -	$ -	$ 15	$ (225)
Construction in Progress - CIAC	N/A	N/A	$ (145)	$ -	$ -	$ -	$ (145)	$ -	$ -	$ -	$ -	$ -	$ (145)
Construction in Progress - Substation Equip	N/A	N/A	$ 64	$ -	$ -	$ -	$ 64	$ -	$ -	$ -	$ -	$ -	$ 64
Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 453	$ -	$ -	$ -	$ 453	$ -	$ -	$ -	$ -	$ -	$ 453
Construction in Progress - Overhead	N/A	N/A	$ 1,217	$ -	$ -	$ -	$ 1,217	$ -	$ -	$ -	$ -	$ -	$ 1,217
Construction in Progress - Underground	N/A	N/A	$ 2,181	$ -	$ -	$ -	$ 2,181	$ -	$ -	$ -	$ -	$ -	$ 2,181
Construction in Progress - Building Brick	N/A	N/A	$ 87	$ -	$ -	$ -	$ 87	$ -	$ -	$ -	$ -	$ -	$ 87
Construction in Progress - Rolling Stock	N/A	N/A	$ 90	$ -	$ -	$ -	$ 90	$ -	$ -	$ -	$ -	$ -	$ 90
Construction in Progress - Green Energy	N/A	N/A	$ 147	$ -	$ -	$ -	$ 147	$ -	$ -	$ -	$ -	$ -	$ 147
Construction in Progress - Comp Software	N/A	N/A	$ 425	$ -	$ -	$ -	$ 425	$ -	$ -	$ -	$ -	$ -	$ 425
									$ -				
Total			**$ 561,110**	**$ 46,446**	**$ (2,064)**	**$ (1,027)**	**$ 604,466**	**$ (45,780)**	**$ (26,791)**	**$ 83**	**$ 1,027**	**$ (71,462)**	**$ 533,003**

Appendix 2-B
Fixed Asset Continuity Schedule

Year [1] 2014 IFRS

					Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Useful life**	**Depreciation Rate**	**Opening Balance**	**Additions**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Opening Balance**	**Additions**	**Early Derecognition**	**Retirements**	**Closing Balance**	**Net Book Value**
N/A	1905	Land	N/A	N/A	$ 9,069	$ -	$ -	$ -	$ 9,069	$ -	$ -	$ -	$ -	$ -	$ 9,069
CEC	1906	Land Rights /Easements	N/A	N/A	$ 2,332	$ -	$ -	$ -	$ 2,332	$ -	$ -	$ -	$ -	$ -	$ 2,332
1	1808	Buildings and Fixtures	60	1.67%	$ 20,551	$ 982	$ -	$ -	$ 21,533	$ (936)	$ (421)	$ -	$ -	$ (1,357)	$ 20,176
1	1808	Buildings and Fixtures (Improvements)	20	5.00%	$ 18,823	$ 3,468	$ -	$ -	$ 22,292	$ (1,844)	$ (1,107)	$ -	$ -	$ (2,951)	$ 19,341
47	1820	Distribution Station Equipment <50 kV	40	2.50%	$ 60,743	$ 3,364	$ (107)	$ -	$ 64,000	$ (5,348)	$ (1,960)	$ 4	$ -	$ (7,304)	$ 56,696
47	1820	Wholesale Meters	25	4.00%	$ 6,061	$ -	$ -	$ -	$ 6,061	$ (587)	$ (256)	$ -	$ -	$ (843)	$ 5,217
47	1980	System Supervisor Equipment (Scadamate/Re	25	4.00%	$ 7,528	$ 678	$ (16)	$ (41)	$ 8,150	$ (1,252)	$ (454)	$ 1	$ 41	$ (1,665)	$ 6,485
47	1980	System Supervisor Equipment (Scada/Pro & D	15	6.67%	$ 7,200	$ 1,501	$ -	$ (55)	$ 8,646	$ (1,540)	$ (671)	$ -	$ 55	$ (2,156)	$ 6,490
47	1830	O/H Wood Pole Systems	45	2.22%	$ 29,806	$ 2,152	$ (205)	$ -	$ 31,753	$ (2,216)	$ (827)	$ 8	$ -	$ (3,035)	$ 28,719
47	1830	O/H Concrete Pole Syst	55	1.82%	$ 68,570	$ 5,003	$ (111)	$ -	$ 73,461	$ (3,862)	$ (1,465)	$ 4	$ -	$ (5,322)	$ 68,139
47	1850	O/H Transformer System	45	2.22%	$ 11,808	$ 940	$ (67)	$ -	$ 12,682	$ (868)	$ (333)	$ 3	$ -	$ (1,199)	$ 11,483
47	1835	O/H Switches/Fuses	40	2.50%	$ 16,687	$ 1,272	$ (320)	$ -	$ 17,639	$ (1,432)	$ (548)	$ 13	$ -	$ (1,967)	$ 15,673
47	1835	O/H Fault Indicators	10	10.00%	$ 665	$ 205	$ (5)	$ (29)	$ 835	$ (177)	$ (89)	$	$ 29	$ (237)	$ 598
47	1845	Underground Cable	40	2.50%	$ 160,251	$ 11,558	$ (801)	$ (48)	$ 170,960	$ (15,481)	$ (5,731)	$ 32	$ 48	$ (21,132)	$ 149,828
47	1850	PadMounted Transformers	35	2.86%	$ 46,774	$ 2,340	$ (453)	$ (610)	$ 48,051	$ (6,386)	$ (2,190)	$ 18	$ 610	$ (7,948)	$ 40,103
47	1840	Duct & Foundations	50	2.00%	$ 39,936	$ 3,023	$ -	$ -	$ 42,959	$ (2,709)	$ (1,018)	$ -	$ -	$ (3,727)	$ 39,232
47	1845	Underground Accessories	20	5.00%	$ 7,870	$ 472	$ (13)	$ (184)	$ 8,146	$ (2,070)	$ (760)	$ 1	$ 184	$ (2,645)	$ 5,501
47	1845	Air Insulated Switchgear	25	4.00%	$ 2,180	$ 30	$ (28)	$ (57)	$ 2,124	$ (535)	$ (176)	$ 1	$ 57	$ (653)	$ 1,471
47	1845	Solid Dielectric Switchgear	35	2.86%	$ 2,941	$ 1,298	$ -	$ -	$ 4,240	$ (114)	$ (103)	$ -	$ -	$ (217)	$ 4,023
47	1860	Other Conventional Meters	25	4.00%	$ 4,925	$ 398	$ -	$ -	$ 5,323	$ (395)	$ (335)	$ -	$ -	$ (730)	$ 4,593
47	1860	Meters (Smart Meters - New)	15	6.67%	$ 973	$ 332	$ -	$ -	$ 1,305	$ (89)	$ (76)	$ -	$ -	$ (165)	$ 1,140
47	1860	Meters (Smart Meters New Condos)	15	6.67%	$ 5,517	$ 1,383	$ -	$ -	$ 6,900	$ (896)	$ (438)	$ -	$ -	$ (1,334)	$ 5,566
47	1860	Green Energy - FIT/Micro	15	6.67%	$ 678	$ 385	$ -	$ -	$ 1,063	$ (52)	$ (57)	$ -	$ -	$ (108)	$ 955
47	1555	Meters (Smart Meters)	15	6.67%	$ 25,924	$ -	$ -	$ -	$ 25,924	$ (5,776)	$ (1,974)	$ -	$ -	$ (7,750)	$ 18,174
47	1555	Meters (Smart Meters Hazardous Meters)	15	6.67%	$ 976	$ -	$ -	$ -	$ 976	$ (199)	$ (67)	$ -	$ -	$ (266)	$ 710
50	1555	Computer Equip - Meters (Smart Meters)	5	20.00%	$ 75	$ -	$ -	$ (75)	$ -	$ (64)	$ (11)	$ -	$ 75	$ ()	$ ()
12	1555	Computer Software (Smart Meters)	5	20.00%	$ 3,392	$ -	$ -	$ -	$ 3,392	$ (1,468)	$ (619)	$ -	$ -	$ (2,087)	$ 1,305
8	1915	General Equipment & Office Furniture	10	10.00%	$ 5,799	$ 1,603	$ -	$ (77)	$ 7,325	$ (1,909)	$ (850)	$ -	$ 77	$ (2,682)	$ 4,643
10/10.1	1930	Transportation Equipment (Cars and Supervis	4	25.00%	$ 584	$ 289	$ -	$ (90)	$ 783	$ (254)	$ (188)	$ -	$ 90	$ (352)	$ 431
10	1930	Transportation Equipment (Double Bucket & R	12	8.33%	$ 3,632	$ 593	$ -	$ (4)	$ 4,221	$ (822)	$ (375)	$ -	$ 4	$ (1,193)	$ 3,028
10	1930	Transportation Equipment (Single Buckets, Du	8	12.50%	$ 3,543	$ 198	$ -	$ (143)	$ 3,598	$ (1,554)	$ (562)	$ -	$ 143	$ (1,973)	$ 1,625
10	1930	Transportation Equipment (Trailers)	15	6.67%	$ 899	$ 190	$ -	$ (2)	$ 1,088	$ (169)	$ (73)	$ -	$ 2	$ (239)	$ 848
10	1930	Transportation Equipment (Trucks & Vans)	5	20.00%	$ 1,646	$ 573	$ -	$ (36)	$ 2,183	$ (464)	$ (379)	$ -	$ 36	$ (808)	$ 1,376
8	1940	Major Tools	10	10.00%	$ 1,544	$ 200	$ -	$ (51)	$ 1,693	$ (518)	$ (205)	$ -	$ 51	$ (673)	$ 1,020
50	1920	Computer Equipment - Hardware (Desktop)	3	33.33%	$ 961	$ 118	$ -	$ (321)	$ 759	$ (508)	$ (287)	$ -	$ 321	$ (474)	$ 286
50	1920	Computer Equipment - Hardware (Network)	5	20.00%	$ 4,995	$ 429	$ -	$ (1,273)	$ 4,150	$ (2,734)	$ (993)	$ -	$ 1,273	$ (2,453)	$ 1,697
50	1920	Computer Equipment - Hardware (Corporate)	10	10.00%	$ 263	$ -	$ -	$ -	$ 263	$ (112)	$ (39)	$ -	$ -	$ (151)	$ 112
12	1925	Computer Software (10 year)	10	10.00%	$ 22,664	$ 3,248	$ -	$ -	$ 25,912	$ (6,148)	$ (2,685)	$ -	$ -	$ (8,833)	$ 17,079
12	1925	Computer Software (2 year)	2	50.00%	$ 169	$ 94	$ -	$ (75)	$ 187	$ (80)	$ (101)	$ -	$ 75	$ (106)	$ 82
12	1925	Computer Software (5 year)	5	20.00%	$ 1,185	$ 263	$ -	$ -	$ 1,448	$ (328)	$ (159)	$ -	$ -	$ (487)	$ 961
47	1995	Contributions & Grants - Wood Poles	45	2.22%	$ (59)	$ (8)	$ -	$ -	$ (68)	$ 3	$ 1	$ -	$ -	$ 4	$ (64)
47	1995	Contributions & Grants - Concrete Poles	55	1.82%	$ (2,299)	$ (520)	$ -	$ -	$ (2,819)	$ 76	$ 47	$ -	$ -	$ 123	$ (2,696)
47	1995	Contributions & Grants - OH TX	45	2.22%	$ (612)	$ (211)	$ -	$ -	$ (823)	$ 20	$ 16	$ -	$ -	$ 36	$ (787)
47	1995	Contributions & Grants - OH Switches	40	2.50%	$ (332)	$ (93)	$ -	$ -	$ (425)	$ 14	$ 9	$ -	$ -	$ 23	$ (402)
47	1995	Contributions & Grants - OH Fault Indicators	10	10.00%	$ ()	$ ()	$ -	$ -	$ (1)	$	$	$ -	$ -	$	$ ()
47	1995	Contributions & Grants - UG Cable	40	2.50%	$ (4,132)	$ (1,124)	$ -	$ -	$ (5,256)	$ 174	$ 117	$ -	$ -	$ 291	$ (4,965)
47	1995	Contributions & Grants - Padmounted TX	35	2.86%	$ (1,062)	$ (458)	$ -	$ -	$ (1,520)	$ 37	$ 37	$ -	$ -	$ 73	$ (1,447)
47	1995	Contributions & Grants - Duct & Foundation	50	2.00%	$ (1,051)	$ (261)	$ -	$ -	$ (1,312)	$ 37	$ 24	$ -	$ -	$ 60	$ (1,252)
47	1995	Contributions & Grants - UG Accessories	20	5.00%	$ (369)	$ (105)	$ -	$ -	$ (475)	$ 57	$ 42	$ -	$ -	$ 99	$ (376)
47	1995	Contributions & Grants - Switchgear	35	2.86%	$ (37)	$ (18)	$ -	$ -	$ (55)	$ 1	$ 2	$ -	$ -	$ 3	$ (52)
47	1995	Contributions & Grants - FIT/MicroFIT	15	6.67%	$ (240)	$ (160)	$ -	$ -	$ (400)	$ 15	$ 21	$ -	$ -	$ 36	$ (364)
N/A	2055	Construction in Progress - CIAC	N/A	N/A	$ (145)	$ -	$ -	$ -	$ (145)	$ -	$ -	$ -	$ -	$ -	$ (145)
N/A	2055	Construction in Progress - Substation Equip	N/A	N/A	$ 64	$ -	$ -	$ -	$ 64	$ -	$ -	$ -	$ -	$ -	$ 64
N/A	2055	Construction in Progress - Suprv Ctrl Equip	N/A	N/A	$ 453	$ -	$ -	$ -	$ 453	$ -	$ -	$ -	$ -	$ -	$ 453
N/A	2055	Construction in Progress - Overhead	N/A	N/A	$ 1,217	$ -	$ -	$ -	$ 1,217	$ -	$ -	$ -	$ -	$ -	$ 1,217
N/A	2055	Construction in Progress - Underground	N/A	N/A	$ 2,181	$ -	$ -	$ -	$ 2,181	$ -	$ -	$ -	$ -	$ -	$ 2,181
N/A	2055	Construction in Progress - Building Brick	N/A	N/A	$ 87	$ -	$ -	$ -	$ 87	$ -	$ -	$ -	$ -	$ -	$ 87
N/A	2055	Construction in Progress - Rolling Stock	N/A	N/A	$ 90	$ -	$ -	$ -	$ 90	$ -	$ -	$ -	$ -	$ -	$ 90
N/A	2055	Construction in Progress - Green Energy	N/A	N/A	$ 147	$ -	$ -	$ -	$ 147	$ -	$ -	$ -	$ -	$ -	$ 147
N/A	2055	Construction in Progress - Comp Software	N/A	N/A	$ 425	$ -	$ -	$ -	$ 425	$ -	$ -	$ -	$ -	$ -	$ 425
											$ -				
		Total			**$ 604,466**	**$ 45,624**	**$ (2,126)**	**$ (3,171)**	**$ 644,792**	**$ (71,462)**	**$ (28,264)**	**$ 85**	**$ 3,171**	**$ (96,470)**	**$ 548,322**

Gross Assets – Property, Plant, and Equipment

The following tables provide continuity schedules of gross capital assets for each year starting from the 2008 opening balances to the forecast closing balances for 2014.

Exhibit 2 Tab 1 Schedule 1 Appendix 2-B provides further details of these continuity schedules by Uniform System of Accounts ("USofA") for the 2008 to 2011 actuals, 2012 Bridge, 2013 Test, and 2014 ICR Years.

Table 1: Gross Assets 2008 CGAAP - Actual ($000s)

Description	Opening Balance	Additions	Disposals /Retirements	Closing Balance
Land and Buildings	$ 19,400	$ 1,284	$ ()	$ 20,684
Distribution Station	$ 67,914	$ 4,762	$ (2,214)	$ 70,462
Poles, Wires	$ 586,178	$ 31,366	$ (2,665)	$ 614,879
Line Transformers	$ 68,462	$ 548	$ (885)	$ 68,124
Services and Meters	$ 41,475	$ 8,325	$ (2,445)	$ 47,354
Equipment	$ 22,638	$ 2,291	$ (2,349)	$ 22,580
IT Assets	$ 8,649	$ 2,341	$ (2,719)	$ 8,271
Other Distribution Assets	$ 13,883	$ 1,102	$ (761)	$ 14,224
CIP	$ 8,102	$ 7,136	$ -	$ 15,239
Customer Contributions	$ (70,422)	$ (7,651)	$ -	$ (78,073)
Closing Balance	$ 766,280	$ 51,503	$ (14,039)	$ 803,744
Average Gross Asset Balance	**$ 745,916**	**$ 49,062**	**$ (9,966)**	**$ 785,012**

The amount shown in the disposals column for the services and meters category in Table 1 includes a net book value write-off of $2,107 related to the stranded meters and has been allocated to USofA 1555. Further explanation of the movement of charges to the 1555 account is provided at Exhibit 9 Tab 2 Schedule 2.

Table 2: Gross Assets 2009 CGAAP - Actual ($000s)

Description	Opening Balance	Additions	Disposals /Retirements	Closing Balance
Land and Buildings	$ 20,684	$ 499	$ -	$ 21,183
Distribution Station	$ 70,462	$ 7,972	$ (2,216)	$ 76,218
Poles, Wires	$ 614,879	$ 23,898	$ (3,104)	$ 635,673
Line Transformers	$ 68,124	$ 386	$ (1,285)	$ 67,225
Services and Meters	$ 47,354	$ 10,367	$ (3,828)	$ 53,893
Equipment	$ 22,580	$ 3,456	$ (2,390)	$ 23,646
IT Assets	$ 8,271	$ 14,534	$ (1,349)	$ 21,456
Other Distribution Assets	$ 14,224	$ 2,222	$ (365)	$ 16,081
CIP	$ 15,239	$ (10,391)	$ -	$ 4,847
Customer Contributions	$ (78,073)	$ 6,399	$ -	$ (71,674)
Closing Balance	$ 803,744	$ 59,342	$ (14,537)	$ 848,548
Average Gross Asset Balance	**$ 785,012**	**$ 55,422**	**$ (14,288)**	**$ 826,146**

The amount shown in the disposal column for the services and meters category in Table 2 includes a net book value write-off of $3,635 related to the stranded meters and has been allocated to USofA 1555.

Table 3: Gross Assets 2010 CGAAP - Actual ($000s)

Description	Opening Balance	Additions	Disposals /Retirements	Closing Balance
Land and Buildings	$ 21,183	$ 1,522	$ -	$ 22,705
Distribution Station	$ 76,218	$ 3,875	$ (235)	$ 79,857
Poles, Wires	$ 635,673	$ 39,365	$ (217)	$ 674,820
Line Transformers	$ 67,225	$ 33	$ (3,819)	$ 63,439
Services and Meters	$ 53,893	$ 9,149	$ (4,011)	$ 59,031
Equipment	$ 23,646	$ 1,683	$ (1,643)	$ 23,685
IT Assets	$ 21,456	$ 2,817	$ (2,307)	$ 21,966
Other Distribution Assets	$ 16,081	$ 1,083	$ (115)	$ 17,048
CIP	$ 4,847	$ 3,553	$ -	$ 8,400
Customer Contributions	$ (71,674)	$ (10,050)	$ -	$ (81,724)
Closing Balance	$ 848,548	$ 53,028	$ (12,348)	$ 889,228
Average Gross Asset Balance	**$ 826,146**	**$ 56,185**	**$ (13,443)**	**$ 868,888**

The amount shown in the disposals column for the services and meters category in Table 3 includes a net book value write-off of $3,034 related to the stranded meters and has been allocated to USofA 1555.

Table 4: Gross Assets 2011 MIFRS - Actual ($000s)

Description	Opening Balance	Additions	Transfers	Derecognition	Disposals /Retirements	Closing Balance
Land and Buildings	$ 16,557	$ 2,668		$ -	$ (1)	$ 19,224
Distribution Station	$ 49,454	$ 4,715	$ 3,281	$ (98)	$ -	$ 57,353
Poles, Wires	$ 264,797	$ 24,804		$ (1,353)	$ (1,038)	$ 287,210
Line Transformers	$ 50,307	$ 3,472		$ (475)	$ (9)	$ 53,294
Services and Meters	$ 37,218	$ 5,932	$ (3,281)	$ -	$ (937)	$ 38,931
Equipment	$ 10,456	$ 2,292		$ -	$ (149)	$ 12,599
IT Assets	$ 16,278	$ 5,539		$ -	$ (399)	$ 21,418
Other Distribution Assets	$ 10,859	$ 1,276		$ -	$ (498)	$ 11,637
CIP	$ 8,400	$ (3,780)		$ -	$ -	$ 4,620
Customer Contributions	$ -	$ (4,353)		$ -	$ -	$ (4,353)
Closing Balance	$ 464,327	$ 42,563	$ -	$ (1,926)	$ (3,032)	$ 501,932
Average Gross Asset Balance	**$ 656,438**	**$ 47,795**	**$ -**	**$ (963)**	**$ (7,690)**	**$ 695,580**

Opening balances for MIFRS represent the ending net book values of capital assets as of December 31, 2010. A reconciliation of the opening values for MIFRS is explained in detail in Exhibit 2 Tab 1 Schedule 1.

The amount of $3,281, shown under the transfers column in Table 4 represents the re-classification of wholesale meters from USofA 1860 Meters to USofA account 1820 Distribution Station Equipment - Normally Primary below 50 kV.

The derecognition column represents the actual cost of assets removed prematurely from the distribution system. This column has been shown separately from disposals/retirements column to differentiate the IFRS impact.

The disposals/retirements column represent other assets removed from the field at the end of useful lives or prior to reaching their useful lives. This column includes:

- A net book value write-off of $908 (a cost of $933 less accumulated depreciation of $25) related to the stranded meters and recorded to USofA 1555; and

- A one-time net book value write-off of $1,312 as a result of IFRS implementation relating to assets that were determined to have a shorter useful life than prior pooled assets. This write-off has been coded as depreciation expense for MIFRS.

Table 5: Gross Assets 2012 MIFRS - Bridge Budget ($000s)

Description	Opening Balance	Additions	Derecognition	Disposals /Retirements	Closing Balance
Land and Buildings	$ 19,224	$ 22,340	$ -	$ -	$ 41,564
Distribution Station	$ 57,353	$ 6,515	$ (101)	$ -	$ 63,767
Poles, Wires	$ 287,210	$ 22,363	$ (1,399)	$ (447)	$ 307,727
Line Transformers	$ 53,294	$ 3,166	$ (490)	$ -	$ 55,971
Services and Meters	$ 38,931	$ 3,653	$ -	$ (1,859)	$ 40,725
Equipment	$ 12,599	$ 2,831	$ -	$ (546)	$ 14,884
IT Assets	$ 21,418	$ 5,180	$ -	$ (371)	$ 26,228
Other Distribution Assets	$ 11,637	$ 1,445	$ (15)	$ (82)	$ 12,985
CIP	$ 4,620	$ (101)	$ -	$ -	$ 4,519
Customer Contributions	$ (4,353)	$ (2,907)	$ -	$ -	$ (7,260)
Closing Balance	$ 501,932	$ 64,486	$ (2,004)	$ (3,304)	$ 561,110
Average Gross Asset Balance	**$ 483,130**	**$ 53,524**	**$ (1,965)**	**$ (3,168)**	**$ 531,521**

The derecognition column in Table 5 represents the actual cost of assets removed prematurely from the distribution system and is shown separately from the disposals/retirements column to differentiate the IFRS impact.

The disposals/retirements column represents other assets removed from the field prior to or at the end of their useful lives. Included in these numbers is the net book value write-off of $1,300 (a cost of $1,800 less accumulated depreciation of $500) related to the stranded meters disposal.

Table 6: Gross Assets 2013 MIFRS - Test Year Budget ($000s)

Description	Opening Balance	Additions	Derecognition	Retirements	Closing Balance
Land and Buildings	$ 41,564	$ 9,212	$ -	$ -	$ 50,776
Distribution Station	$ 63,767	$ 3,140	$ (104)	$ -	$ 66,804
Poles, Wires	$ 307,727	$ 22,855	$ (1,441)	$ (236)	$ 328,906
Line Transformers	$ 55,971	$ 3,116	$ (504)	$ -	$ 58,582
Services and Meters	$ 40,725	$ 1,956	$ -	$ (220)	$ 42,461
General Plant					$ -
Equipment	$ 14,884	$ 3,166	$ -	$ (404)	$ 17,646
IT Assets	$ 26,228	$ 4,125	$ -	$ (115)	$ 30,237
Other Distribution Assets	$ 12,985	$ 1,810	$ (15)	$ (51)	$ 14,728
CIP	$ 4,519	$ -	$ -	$ -	$ 4,519
Customer Contributions	$ (7,260)	$ (2,933)	$ -	$ -	$ (10,193)
Closing Balance	$ 561,110	$ 46,446	$ (2,064)	$ (1,027)	$ 604,466
Average Gross Asset Balance	**$ 531,521**	**$ 55,466**	**$ (2,034)**	**$ (2,166)**	**$ 582,788**

The derecognition column in Table 6 represents the actual cost of assets expected to be removed prematurely from the distribution system and is shown separately from the disposals/retirements column to differentiate the IFRS impact. The disposals/retirements column represents other assets removed from the field prior to or at the end of their useful lives.

Table 7: Gross Assets Year 2014 MIFRS – 2014 Budget ($000s)

Description	Opening Balance	Additions	Derecognition	Retirements	Closing Balance
Land and Buildings	$ 50,776	$ 4,451	$ -	$ -	$ 55,226
Distribution Station	$ 66,804	$ 3,364	$ (107)	$ -	$ 70,061
Poles, Wires	$ 328,906	$ 25,014	$ (1,484)	$ (319)	$ 352,117
Line Transformers	$ 58,582	$ 3,280	$ (520)	$ (610)	$ 60,733
Services and Meters	$ 42,461	$ 2,498	$ -	$ (75)	$ 44,884
Equipment	$ 17,646	$ 3,646	$ -	$ (402)	$ 20,890
IT Assets	$ 30,237	$ 4,152	$ -	$ (1,669)	$ 32,719
Other Distribution Assets	$ 14,728	$ 2,180	$ (16)	$ (96)	$ 16,796
CIP	$ 4,519	$ -	$ -	$ -	$ 4,519
Customer Contributions	$ (10,193)	$ (2,960)	$ -	$ -	$ (13,153)
Closing Balance	$ 604,466	$ 45,624	$ (2,126)	$ (3,171)	$ 644,792
Average Gross Asset Balance	**$ 582,788**	**$ 46,035**	**$ (2,095)**	**$ (2,099)**	**$ 624,629**

The derecognition column in Table 7 represents the actual cost of assets expected to be removed prematurely from the distribution system and is shown separately from the disposals/retirements column to differentiate the IFRS impact. The disposals/retirements column represents other assets removed from the field prior to or at the end of their useful lives.

Accumulated Depreciation

The following tables provide continuity schedules of accumulated depreciation of capital assets for each year starting from the Board-approved 2008 opening balances to the forecast closing balances for 2014.

Exhibit 2 Tab 1 Schedule 1 Appendix 2-B provides the Fixed Asset Continuity Schedule which details the asset cost, depreciation and net book value by Uniform System of Account ("USofA") for the 2008 to 2011 actuals, the 2012 Bridge, the 2013 Test, and the 2014 ICR Years.

Table 1: Accumulated Depreciation 2008 CGAAP – Actual ($000s)

Description	Opening Balance	Additions	Disposals /Retirements	Closing Balance
Land and Buildings	$ (5,046)	$ (334)	$ -	$ (5,380)
Distribution Station	$ (27,682)	$ (2,330)	$ 2,214	$ (27,798)
Poles, Wires	$ (246,867)	$ (23,818)	$ 2,665	$ (268,020)
Line Transformers	$ (42,658)	$ (2,673)	$ 885	$ (44,446)
Services and Meters	$ (18,405)	$ (2,190)	$ 338	$ (20,257)
Equipment	$ (12,676)	$ (2,113)	$ 2,197	$ (12,592)
IT Assets	$ (4,240)	$ (2,519)	$ 2,719	$ (4,040)
Other Distribution Assets	$ (6,811)	$ (840)	$ 761	$ (6,889)
Customer Contributions	$ 11,993	$ 2,970	$ -	$ 14,963
Closing Balance	$ (352,393)	$ (33,847)	$ 11,780	$ (374,460)
Average Acc. Dep. Balance	**$ (339,250)**	**$ (32,976)**	**$ 8,801**	**$ (363,426)**

Table 2: Accumulated Depreciation 2009 CGAAP – Actual ($000s)

Description	Opening Balance	Additions	Disposals /Retirements	Closing Balance
Land and Buildings	$ (5,380)	$ (363)	$ -	$ (5,743)
Distribution Station	$ (27,798)	$ (2,464)	$ 2,216	$ (28,046)
Poles, Wires	$ (268,020)	$ (24,862)	$ 2,999	$ (289,883)
Line Transformers	$ (44,446)	$ (2,660)	$ 1,285	$ (45,821)
Services and Meters	$ (20,257)	$ (2,559)	$ 291	$ (22,525)
Equipment	$ (12,592)	$ (2,278)	$ 2,332	$ (12,538)
IT Assets	$ (4,040)	$ (2,241)	$ 1,349	$ (4,932)
Other Distribution Assets	$ (6,889)	$ (903)	$ 365	$ (7,427)
Customer Contributions	$ 14,963	$ 2,995	$ -	$ 17,958
Closing Balance	$ (374,460)	$ (35,335)	$ 10,838	$ (398,957)
Average Acc. Dep. Balance	**$ (363,426)**	**$ (34,591)**	**$ 11,309**	**$ (386,709)**

Table 3: Accumulated Depreciation 2010 CGAAP – Actual ($000s)

Description	Opening Balance	Additions	Disposals /Retirements	Closing Balance
Land and Buildings	$ (5,743)	$ (404)	$ -	$ (6,147)
Distribution Station	$ (28,046)	$ (2,593)	$ 235	$ (30,403)
Poles, Wires	$ (289,883)	$ (26,050)	$ 217	$ (315,716)
Line Transformers	$ (45,821)	$ (2,625)	$ 3,819	$ (44,627)
Services and Meters	$ (22,525)	$ (3,138)	$ 977	$ (24,685)
Equipment	$ (12,538)	$ (2,317)	$ 1,626	$ (13,229)
IT Assets	$ (4,932)	$ (3,064)	$ 2,307	$ (5,688)
Other Distribution Assets	$ (7,427)	$ (991)	$ 115	$ (8,303)
Customer Contributions	$ 17,958	$ 3,068	$ -	$ 21,026
Closing Balance	$ (398,957)	$ (38,114)	$ 9,297	$ (427,774)
Average Acc. Dep. Balance	**$ (386,709)**	**$ (36,724)**	**$ 10,067**	**$ (413,366)**

Table 4: Accumulated Depreciation 2011 MIFRS – Actual ($000s)

Description	Opening Balance	Additions	Transfers	Derecognition	Disposals /Retirements	Closing Balance
Land and Buildings	$ -	$ (532)		$ -	$	$ (532)
Distribution Station	$ -	$ (1,689)	$ (131)	$ 5	$ -	$ (1,815)
Poles, Wires	$ -	$ (9,625)		$ 41	$ 240	$ (9,344)
Line Transformers	$ -	$ (2,349)		$ 21	$ -	$ (2,328)
Services and Meters	$ -	$ (3,044)	$ 131	$ -	$ 29	$ (2,884)
Equipment	$ -	$ (2,151)		$ -	$ 65	$ (2,086)
IT Assets	$ -	$ (3,282)		$ -	$ 341	$ (2,941)
Other Distribution Assets	$ -	$ (968)		$ -	$ 50	$ (919)
Customer Contributions	$ -	$ 51		$ -	$ -	$ 51
Closing Balance	$ -	$ (23,589)	$ -	$ 67	$ 725	$ (22,797)
Average Acc. Dep. Balance	**$ (199,479)**	**$ (30,851)**	**$ -**	**$ 34**	**$ 5,011**	**$ (225,286)**

Opening balances for MIFRS as of January 1, 2011 are zero as explained in detail in Exhibit 2 Tab 1 Schedule 1.

The amount of $131 in Table 4, shown under the transfers column, represents the re-classification of wholesale meters from USofA 1860 Meters to USofA account 1820 Distribution Station Equipment - Normally Primary below 50 kV.

The derecognition column in Table 4 represents the actual accumulated depreciation of assets removed prematurely from the distribution system before

reaching the end of their useful lives. This column has been presented separately from the disposals/retirements column to differentiate the IFRS impact.

Table 5: Accumulated Depreciation 2012 MIFRS – Forecast ($000s)

Description	Opening Balance	Additions	Derecognition	Closing Balance
Land and Buildings	$ (532)	$ (933)	$ -	$ (1,465)
Distribution Station	$ (1,815)	$ (1,993)	$ 4	$ (3,804)
Poles, Wires	$ (9,344)	$ (9,839)	$ 56	$ (18,681)
Line Transformers	$ (2,328)	$ (2,441)	$ 20	$ (4,749)
Services and Meters	$ (2,884)	$ (3,340)	$ -	$ (5,665)
Equipment	$ (2,086)	$ (2,215)	$ -	$ (3,755)
IT Assets	$ (2,941)	$ (3,480)	$ -	$ (6,050)
Other Distribution Assets	$ (919)	$ (975)	$ 1	$ (1,812)
Customer Contributions	$ 51	$ 150	$ -	$ 201
Closing Balance	$ (22,797)	$ (25,068)	$ 80	$ (45,780)
Average Acc. Dep. Balance	**$ (11,399)**	**$ (24,329)**	**$ 74**	**$ (34,289)**

The derecognition column in Table 5 represents the accumulated depreciation of assets expected to be removed prematurely from the distribution system before reaching the end of their useful lives. This column has been presented separately from the disposals/retirements column to differentiate the IFRS impact.

Table 6: Accumulated Depreciation 2013 MIFRS – Forecast ($000s)

Description	Opening Balance	Additions	Derecognition	Closing Balance
Land and Buildings	$ (1,465)	$ (1,316)	$ -	$ (2,781)
Distribution Station	$ (3,804)	$ (2,135)	$ 4	$ (5,935)
Poles, Wires	$ (18,681)	$ (10,209)	$ 58	$ (28,596)
Line Transformers	$ (4,749)	$ (2,525)	$ 20	$ (7,254)
Services and Meters	$ (5,665)	$ (3,494)	$ -	$ (8,939)
Equipment	$ (3,755)	$ (2,340)	$ -	$ (5,691)
IT Assets	$ (6,050)	$ (3,974)	$ -	$ (9,908)
Other Distribution Assets	$ (1,812)	$ (1,032)	$ 1	$ (2,792)
Customer Contributions	$ 201	$ 232	$ -	$ 433
Closing Balance	$ (45,780)	$ (26,791)	$ 83	$ (71,462)
Average Acc. Dep. Balance	**$ (34,289)**	**$ (25,930)**	**$ 81**	**$ (58,621)**

The derecognition column in Table 6 represents the accumulated depreciation of assets expected to be removed prematurely from the distribution system before reaching the end of their useful lives. This column has been presented separately from the disposals/retirements column to differentiate the IFRS impact.

Table 7: Accumulated Depreciation 2014 MIFRS – Forecast ($000s)

Description	Opening Balance	Additions	Derecognition	Closing Balance
Land and Buildings	$ (2,781)	$ (1,527)	$ -	$ (4,308)
Distribution Station	$ (5,935)	$ (2,216)	$ 4	$ (8,147)
Poles, Wires	$ (28,596)	$ (10,716)	$ 59	$ (38,934)
Line Transformers	$ (7,254)	$ (2,523)	$ 21	$ (9,146)
Services and Meters	$ (8,939)	$ (3,577)	$ -	$ (12,441)
Equipment	$ (5,691)	$ (2,631)	$ -	$ (7,920)
IT Assets	$ (9,908)	$ (4,265)	$ -	$ (12,504)
Other Distribution Assets	$ (2,792)	$ (1,125)	$ 1	$ (3,821)
Customer Contributions	$ 433	$ 317	$ -	$ 750
Closing Balance	$ (71,462)	$ (28,264)	$ 85	$ (96,470)
Average Acc. Dep. Balance	**$ (58,621)**	**$ (27,528)**	**$ 84**	**$ (83,966)**

The derecognition column in Table 7 represents the accumulated depreciation of assets expected to be removed prematurely from the distribution system before reaching the end of their useful lives. This column has been presented separately from the disposals/retirements column to differentiate the IFRS impact.

Working Capital Requirement

Enersource proposes a Working Capital Allowance of $107,241 for the 2013 Test Year, which relies on a working capital allowance percentage of 13.5%. Table 1 illustrates the working capital requirements from the Board-approved 2008 Base Year to the 2013 Test Year.

Table 1: Allowance for Working Capital, 2008 to 2013 ($000s)

	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual MIFRS	2012 Bridge	2013 Test
Cost of Power	605,573	577,135	579,575	675,255	683,116	704,313	733,280
OM&A Expenses	40,476[1]	36,234	41,524	45,599	50,783	57,009	61,099
Total Eligible Expenses for Working Capital	646,049	613,198	620,407	720,023	733,900	761,322	794,379
Working Capital Allowance %	13.3%	13.3%	13.3%	13.3%	13.3%	13.3%	13.5%
Total Working Capital Allowance	85,925	81,578	82,606	95,874	97,609	101,256	107,241

Details supporting the cost of power calculation can be found in Table 2 below and details supporting the OM&A expenses can be found in Exhibit 4 .

[1] EB-2007-0706 Settlement Agreement dated December 21, 2007, page 16. Note that this differs from Table 1 of Exhibit 4 Tab 1 Schedule 1. Smart meter OM&A costs of $1,177 have been added to Exhibit 4 Tab 1 Schedule 1 Table 1 for comparison purposes in that exhibit.

Table 2: Cost of Power, 2008 to 2013 ($000s)

	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Energy	477,162	423,839	318,499	372,953	352,270	363,350	382,756
Wholesale Market Service Rate	51,393	50,195	49,572	51,760	51,210	48,805	48,501
Network Charge	41,339	38,431	39,601	45,740	45,885	48,310	48,523
Connection Charge	35,680	35,790	36,493	39,052	38,008	37,633	37,797
Global Adjustment	-	28,880	135,409	165,751	195,742	206,214	215,704
Total Cost of Power	605,573	577,135	579,575	675,255	683,115	704,313	733,280

Exhibit 1 Tab 2 Schedule 2 details the assumptions relied upon to support the cost of power calculation.

The Board's approval of Enersource's 2008 COS Rate Application in EB-2007-0706 included the acceptance of a negotiated settlement agreement which included the requirement for Enersource to undertake a formal lead/lag study. The Settlement Agreement states[2]:

> "The originally proposed Working Capital Allowance for the 2008 Test Year was $96.477 million, based on the Board's default of 15% of Cost of Power plus expenses. The parties acknowledge that some other LDCs have done detailed studies of working capital requirements, and found that their actual needs are lower than the 15% figure. The parties have agreed that Enersource shall carry out a formal Lead/Lag study and will table that study no later than the summer of 2009. The revised Working Capital Allowance for

[2] EB-2007-0706 Settlement Agreement dated December 21, 2007, page 10.

> the 2008 Test Year will be $85.925 million. This amount was determined as 13.3% of the sum of the 2008 Cost of Power and the 2008 OM&A expenses. The parties agree that the results of the Applicant's Lead/Lag study will not be implemented until Enersource's next rate rebasing application, at which time the Board will determine on the available evidence, including that study, the appropriate Working Capital Allowance to be applied".

The Working Capital Study supporting the calculation of the working capital allowance percentage of 13.5% can be found at Exhibit 2 Tab 1 Schedule 4 Appendix 1. Navigant Consulting Inc. ("NCI") was retained by Enersource to perform an independent review of its lead/lag study. The conclusions of their review can be found at Exhibit 2 Tab 1 Schedule 4 Appendix 2.

3240 Mavis Road
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September 18, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

Dear Ms. Walli:

RE: **Working Capital Requirement**
Board File No.: EB-2007-0706

The Ontario Energy Board's approval of Enersource Hydro Mississauga's (Enersource's) 2008 cost of service rate application in EB-2007-0706 included acceptance of a negotiated settlement agreement (the Settlement Agreement) which included the requirement for Enersource to carry out a formal lead/lag study no later than the summer of 2009.

The Settlement Agreement also states: "The parties agree that the results of the Applicant's Lead/Lag study will not be implemented until Enersource's next rate rebasing application, at which time the Board will determine on the available evidence, including that study, the appropriate Working Capital Allowance to be applied."

Please find attached the resulting redacted, non-confidential lead/lag study, or as Enersource has titled it, "Working Capital Requirement".

Pursuant to the Board's *Practice Direction on Confidential Filings*, Enersource is filing this redacted, non-confidential version of the Working Capital Requirement in addition to a confidential version under separate cover. Enersource claims the need for confidentiality due to the potential harm to Enersource's future competitive position in negotiations it might undertake with third party providers of services such as meter reading, customer service, customer information systems, billing, collections, payroll, benefits, consulting, credit cards, debt, credit, etc.

Please contact the undersigned if there are any questions.

Sincerely,

Original signed by

Gia M. DeJulio
Director, Regulatory Affairs
gdejulio@enersource.com
905-283-4098

c.c.: Dan Pastoric, Enersource
Norman Wolff, Enersource

Attach.

WORKING CAPITAL REQUIREMENT

Introduction

The Ontario Energy Board's (the OEB's) approval of Enersource Hydro Mississauga's (Enersource's) 2008 cost of service (COS) rate application in EB-2007-0706 included acceptance of a negotiated settlement agreement (the Settlement Agreement) among Enersource and the Intervenors of record (the Intervenors) to carry out a formal lead/lag study no later than the summer of 2009. The originally proposed working capital allowance for the 2008 Test Year was based on the OEB's default of 15%; however, the Settlement Agreement resulted in a negotiated approved working capital requirement of 13.3% for the 2008 Test Year. The purpose of this report is to provide the results of the lead/lag study and determine the working capital requirements for Enersource which are to be implemented in the next COS application. This report is based on 2007 historical data and adjusted for anticipated changes to determine the appropriate working capital requirement for the 2010 Test Year.

Lead/Lag Study

Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility which is determined by a lead/lag study. Cash working capital requirements are strongly associated with the timing of cash inflows versus cash outflows. Cash inflows from revenues earned are generally delayed in the process of providing the service, billing the customer and collecting payment. This is what is known as the "Revenue Lag". The payment of expenses incurred, are also generally delayed mainly due to favorable supplier credit terms creating what is called an "Expense Lead". Alternatively, prepaid revenues would create a "Revenue Lead" and prepaid expenses would create an "Expense Lag". The net effect of these four

possibilities creates what is termed the net lead/lag, which is measured in days. It is the net lead/lag which is used in determining the cash working capital requirement as seen in the formula below.

$$\text{Working Capital Requirement} = \text{2010 Budgeted Costs*} \times \frac{\text{Net (Lead)/Lag}}{365}$$

*Budgeted Costs include: Cost of Power, OM&A, Interest Expense, Income Tax and Debt Retirement Charge

Revenue Lag

Revenue Lag, the number of days between when the service is provided and when cash is collected from customers consists of the following four components:

- Service Lag - The time between when the service is provided and meters are read;
- Billing Lag - The time between when the meters are read and invoices are sent;
- Collections Lag - The time between when the invoices are sent out and payment is received; and
- Payment Processing Lag - The time between when the payment is received and processed.

Service Lag: Meters for residential and selected small commercial classes are read bi-monthly while all remaining customer classes are read monthly. Based on the average number of customers in 2007 in these classes, the following calculation yields an average service lag of 28.70 days.

Table 1: Service Lag in 2007

Customer Class	# of Customers 2007Average	Frequency of Meter Read	Mid-Point of Service Period	Customer Weight	Service Lag
Residential & Small Commercial	162,270	Bi-Monthly	30.42	88.71	26.98
General Service & Large User	20,662	Monthly	15.21	11.29	1.72
Total	182,931				
AVERAGE SERVICE LAG :					**28.70**

Source: Enersource Hydro Mississauga

The mix of residential customers is projected to significantly increase on a year over year basis as compared to General Service and Large User customers due to the smart meter initiative in new and retrofit condominiums. Based on forecasted customers for 2010, the service lag is anticipated to [redacted].

Table 2: Service Lag for 2010

Customer Class	# of Customers 2010 Forecast	Frequency of Meter Read	Mid-Point of Service Period	Customer Weight	Service Lag
Residential	[redacted]	Bi-Monthly	30.42	[redacted]	[redacted]
General Service / Large User	[redacted]	Monthly	15.21	[redacted]	[redacted]
Total	[redacted]				[redacted]
AVERAGE SERVICE LAG :					[redacted]

Source: Enersource Hydro Mississauga

Billing Lag: The time between when the meters are read and the bills are delivered is dependant on the availability of the pricing information provided by the Retailers and by the Independent Electricity System Operator (the IESO). Customers paying the fixed price are invoiced within five days once the meters are read as no pricing information is required. Invoices to those paying a retailer price generally take twelve days to deliver, and General Service and Large Users paying the spot price take approximately nineteen days before the invoice is distributed. Based on revenues generated from each class of rate payers in 2007, the following calculation yields a weighted-average billing lag of 11.91 days.

Table 3: Billing Lag in 2007

2007	Revenue ($)	Weight	# Days to Mail Bill	Weighted Lag
Residential (Fixed)	138,780,106.83	0.2024	5.00	1.012
Residential (Retailer)	22,460,226.14	0.0328	12.00	0.393
GS<50 (Fixed)	57,321,412.82	0.0836	5.00	0.418
GS<50 (Retailer)	11,780,561.84	0.0172	12.00	0.206
GS 50-500 (Fixed)	47,040,436.01	0.0686	5.00	0.343
GS 50-500 (Retailer)	55,350,418.40	0.0807	12.00	0.969
GS 50-500 (Spot)	97,493,900.51	0.1422	19.00	2.701
GS 500-5000 (Fixed)	26,929,380.21	0.0393	5.00	0.196
GS 500-5000 (Retailer)	46,730,395.07	0.0681	12.00	0.818
GS 500-5000 (Spot)	108,509,561.43	0.1582	19.00	3.007
LU (Fixed)	15,689,560.02	0.0229	12.00	0.275
LU (Spot)	54,913,460.09	0.0801	19.00	1.522
Streetlight(Retailer)	2,723,428.54	0.0040	12.00	0.048
Total	**685,722,847.91**	**1.0000**		
AVERAGE BILLING LAG :				**11.91**

Source: Enersource Hydro Mississauga

Enersource is currently in the process of implementing a new Customer Information System (CIS), which will increase the time it takes to upload the meter reads [redacted] In addition, effective November 1, 2009 the MUSH sector customers (municipalities, universities, schools, and hospitals) who are currently protected under Regulated Price Plan (RPP) prices, will be re-classified to either retailer or spot pricing. Taking these two adjustments into consideration, the billing lag will be adjusted from [redacted]. It is also important to note that Enersource has not factored into this calculation any changes related to Time-of-Use (TOU) billing which will create additional burdens in generating customer bills.

Table 4: Billing Lag for 2010

2010	Revenue ($)	Weight	# Days to Mail Bill	Weighted Lag
Residential (Fixed)	138,780,107	0.2024	[redacted]	[redacted]
Residential (Retailer)	22,460,226	0.0328	[redacted]	[redacted]
GS<50 (Fixed)	56,313,730	0.0821	[redacted]	[redacted]
GS<50 (Retailer)	12,788,245	0.0186	[redacted]	[redacted]
GS 50-500 (Fixed)	46,220,943	0.0674	[redacted]	[redacted]
GS 50-500 (Retailer)	50,404,000	0.0735	[redacted]	[redacted]
GS 50-500 (Spot)	103,259,812	0.1506	[redacted]	[redacted]
GS 500-5000 (Fixed)	25,622,354	0.0374	[redacted]	[redacted]
GS 500-5000 (Retailer)	42,770,192	0.0624	[redacted]	[redacted]
GS 500-5000 (Spot)	113,776,791	0.1659	[redacted]	[redacted]
LU (Fixed)	14,774,669	0.0215	[redacted]	[redacted]
LU (Spot)	55,828,351	0.0814	[redacted]	[redacted]
Streetlight(Retailer)	2,723,429	0.0040	[redacted]	[redacted]
Total	**685,722,848**	**1.0000**		
AVERAGE BILLING LAG :				[redacted]

Source: Enersource Hydro Mississauga

Collections Lag: The average collections lag was derived from accounts receivable aging summaries in 2007. The summary shows aging of accounts receivable outstanding by aging day interval. Over-due accounts greater than 365 days are considered write-off accounts. The table below indicates that the average collections lag is 28.12 days.

Table 5: Collection Lag in 2007

2007	Mid Point	Average A/R	Weight	Weighted Average
Current 1-16	12	42,836,185	80.8%	9.69
Overdue 17-46	35	4,664,313	8.8%	3.08
Overdue 47-76	73	2,147,712	4.0%	2.96
Overdue 77-106	126	1,040,486	2.0%	2.47
Overdue 107-136	194	1,942,166	3.7%	7.10
Overdue > 137	365	410,277	0.8%	2.82
Total		53,041,138		
AVERAGE COLLECTIONS LAG :				**28.12**

Source: Enersource Hydro Mississauga

Enersource currently delivers bills which are dated on the day of creation; however, the Ontario Energy Board (the OEB) has mandated that date of bills should reflect the date

of distribution[1]. [redacted] It is also important to note that since the second half of 2008 the collections period has significantly increased due to the economic downturn in the economy. Furthermore, the OEB is currently contemplating an increase to the collection period to support low income electricity customers as part of the Low-income Energy Assistance Program (LEAP)[2]. These impacts would significantly increase the collections lag from the current [redacted]; however, they have not been factored into the calculation.

Payment Processing Lag: This is the lag associated with processing customer payments in the form of pre-authorized payments, cheques, payments via telephone, payments directly to financial institutions, electronic payments and credit card payments. Taking into consideration all of these forms of payment, a payment processing lag of [redacted] was determined as appropriate.

Total Revenue Lag: The sum of service lag, billing lag, collections lag and payment processing lag gives a total of [redacted] or total revenue lag.

Table 6: Total Revenue Lag for Test Year 2010

REVENUE LAG:	ENERSOURCE
AVERAGE SERVICE LAG	[redacted]
AVERAGE BILLING LAG	[redacted]
AVERAGE COLLECTIONS LAG	[redacted]
PAYMENT PROCESSING LAG	[redacted]
TOTAL REVENUE LAG TIME	[redacted]

Source: Enersource Hydro Mississauga

[1] Electricity Distribution Rate Handbook(2000), Section 9.3.2 & Electricity Distribution Rate Handbook(2006), Section 11.3.1
[2] The OEB's Attachment A to Notice of Proposal to Amend Codes, dated March 10, 2009, EB-2007-0722

Expense Lead

Expense Lead is the number of days allowed to pay for goods or services provided by suppliers. The major categories of expenses considered are:

- Cost of Power;
- Operations, Maintenance & Administrative (OM&A);
- Interest on Long Term Debt;
- PILS; and
- Debt Retirement Charge.

Cost of Power:

The IESO provides the supply of power to Enersource on a month to month basis with payment due in the third week of the following month. Also included are retail transmission services for network and connection from Hydro One Networks. Based on actual invoices and payment dates in 2007, the average expense lead time for the cost of power from the IESO and Hydro One Networks is 32.74 and 29.22 days, respectively. By weighting the amounts paid to both providers together, a weighted average expense lead time of 32.65 is calculated.

Table 7: Expense Lead Time for the Cost of Power in 2007 (IESO)

2007	Service Start Date	Service End Date	Payment Date	Amount ($)	Service Lead Time	Pmt Lead Time	Total Lead Time	Weight Factor	Exp Time Lead
January	01/01/2007	31/01/2007	16/02/2007	50,180,113	15.50	16.00	31.50	8.51%	2.68
February	01/02/2007	28/02/2007	16/03/2007	49,741,566	14.00	16.00	30.00	8.44%	2.53
March	01/03/2007	31/03/2007	19/04/2007	50,658,808	15.50	19.00	34.50	8.60%	2.97
April	01/04/2007	30/04/2007	16/05/2007	42,532,363	15.00	16.00	31.00	7.22%	2.24
May	01/05/2007	31/05/2007	18/06/2007	40,613,790	15.50	18.00	33.50	6.89%	2.31
June	01/06/2007	30/06/2007	18/07/2007	58,622,318	15.00	18.00	33.00	9.95%	3.28
July	01/07/2007	31/07/2007	17/08/2007	49,828,595	15.50	17.00	32.50	8.46%	2.75
August	01/08/2007	31/08/2007	19/09/2007	59,028,137	15.50	19.00	34.50	10.02%	3.46
September	01/09/2007	30/09/2007	17/10/2007	48,620,799	15.00	17.00	32.00	8.25%	2.64
October	01/10/2007	31/10/2007	19/11/2007	45,253,568	15.50	19.00	34.50	7.68%	2.65
November	01/11/2007	30/11/2007	18/12/2007	45,471,547	15.00	18.00	33.00	7.72%	2.55
December	01/12/2007	31/12/2007	17/01/2008	48,767,725	15.50	17.00	32.50	8.28%	2.69
AVERAGE WEIGHTED EXPENSE LEAD TIME:									**32.74**

Source: Enersource Hydro Mississauga

Table 8: Expense Lead Time for the Cost of Power in 2007 (Hydro One Networks)

2007	Service Start Date	Service End Date	Payment Date	Amount ($)	Service Lead Time	Pmt Lead Time	Total Lead Time	Weight Factor	Exp Time Lead
January	28/12/2006	26/01/2007	01/02/2007	1,293,926	15.00	6.00	21.00	8.55%	1.80
February	26/01/2007	26/02/2007	12/04/2007	913,459	16.00	45.00	61.00	6.04%	3.68
March	26/02/2007	27/03/2007	17/04/2007	725,166	15.00	21.00	36.00	4.79%	1.73
April	27/03/2007	27/04/2007	11/05/2007	2,057,922	16.00	14.00	30.00	13.60%	4.08
May	27/04/2007	29/05/2007	07/06/2007	1,316,713	16.50	9.00	25.50	8.70%	2.22
June	29/05/2007	27/06/2007	05/07/2007	1,210,843	15.00	8.00	23.00	8.00%	1.84
July	27/06/2007	26/07/2007	07/08/2007	1,248,984	15.00	12.00	27.00	8.26%	2.23
August	26/07/2007	28/08/2007	06/09/2007	1,250,093	17.00	9.00	26.00	8.26%	2.15
September	28/08/2007	27/09/2007	05/10/2007	1,307,228	15.50	8.00	23.50	8.64%	2.03
October	27/09/2007	29/10/2007	08/11/2007	1,360,083	16.50	10.00	26.50	8.99%	2.38
November	29/10/2007	27/11/2007	11/12/2007	1,249,759	15.00	14.00	29.00	8.26%	2.40
December	27/11/2007	28/12/2007	15/01/2008	1,193,937	16.00	18.00	34.00	7.89%	2.68
AVERAGE WEIGTHED EXPENSE LEAD TIME:									**29.22**

Source: Enersource Hydro Mississauga

Table 9: Total Expense Lead Time for the Cost of Power in 2007

	IESO	Hydro One	Total
TOTAL COST OF POWER	589,319,328	15,128,112	604,447,440
WEIGHT	97.50%	2.50%	100.00%
LEAD TIME	32.74	29.22	60.95
AVERAGE WEIGHTED EXPENSE LEAD TIME:	**31.92**	**0.73**	**32.65**

Source: Enersource Hydro Mississauga

Operations, Maintenance & Administration (OM&A):

For the purpose of this study, OM&A includes payroll and benefits, consulting and contract staff, property taxes, purchases made on corporate credit cards, and other OM&A.

A. Payroll & Benefits:

Payroll: All Employees are paid for their services weekly, every Thursday. Payment is withheld for the first week of service creating a service lead time of 3.5 days (service period = 7/2 = 3.5) for union employees, and an additional 6 days the following week as payment is made on the 6th day (Thursday). This is a total lead time of 9.5 days. Non-union employees are paid on the 6th day in the first week of service provided which results in a service lead time of 3.5 days but a lag time of 1 day (prepaid), for a total lead time of 2.5 days. Payroll withholdings (including CPP, EI, Federal Tax, OMERS Pension and Employer Health Tax) are all withdrawn from the bank account by ADP, Enersource's payroll service provider on pay day. Based on union and non-union salaries and withholdings paid out in 2007, an expense lead time of 7.15 days was calculated.

Benefits: In 2007, Manulife Financial was the provider of Extended Health Coverage (EHC), dental (DEN) and long term disability (LTD) and The MEARIE Group was the provider of accidental death and dismemberment (AD&D), and life insurance (LI). Payments are made to Manulife and MEARIE generally at the beginning of the month of the coverage period. Based on actual payment dates in 2007, an expense lag time of 5.02 days was calculated.

WSIB: Premiums to the Workplace Safety Insurance Board (WSIB) for disability benefits are paid in the month following the coverage period which results in an expense lead time of 34.33 days.

For the total of payroll, withholdings, benefits and WSIB, an average lead time of 6.71 days was determined for 2007.

Table 10: Expense Lead Time for Payroll, Benefits & WSIB in 2007

2007	Amount ($)	Exp Lead Time	Weight	Weighted Exp Lead Time
Payroll & Withholdings	32,849,580.05	7.15	0.95	6.76
Benefits	1,708,435.09	-5.02	0.05	(0.25)
WSIB	197,718.99	34.33	0.01	0.20
AVERAGE EXPENSE LEAD TIME:	34,755,734.13			**6.71**

Source: Enersource Hydro Mississauga

B. Consulting and contract staff

Based on invoices from vendors providing consulting and contract services, and their payment terms, an expense lead time of 3.93 was determined. The payment terms have been adjusted to reflect the service period in which the service was provided prior to being invoiced. For example, if a vendor with payment terms of 15 days invoices after one week of services (7 days), then the mid-point of that service period, 3.50 days, will be added to the 15-day payment term for a total of 18.50 days. Vendors with immediate payment terms have been categorized under 5 days, the approximate time it takes to process the invoice and produce the cheque.

Table 11: Expense Lead Time for Contract & Consulting Staff in 2007

2007	Pmt Terms	Amount ($)	Weight	Weighted Lead Time
	5.00	26,965.03	0.01	0.04
	15.00	36,000.00	0.01	0.16
	18.50	193,157.80	0.06	1.07
	20.21	36,933.81	0.01	0.22
	30.00	905,840.30	0.27	8.13
	33.50	447,311.65	0.13	4.48
	45.21	1,288,324.33	0.39	17.42
	-152.50	281,240.03	0.08	(12.83)
	-182.50	57,082.64	0.02	(3.12)
	-547.50	71,119.08	0.02	(11.64)
AVERAGE WEIGHTED LEAD TIME:		**3,343,974.67**		**3.93**

Source: Enersource Hydro Mississauga

C. Property Taxes

The majority of property taxes paid by Enersource are to the City of Mississauga based on six installments per annum. Property taxes are also paid semi-annually to the city of Brampton and Ontario Electricity Financial Corporation. The service lead time is the mid-point of year and the payment lag time is the difference between payment date and the end of the year. The weighted expense lag for 2007 is 26.44 days.

Table 12: Expense Lag Time for Property Taxes in 2007

Amount ($)	Pmt Date	Description	Service Lead Time	Pmt Lead Time	Exp Lead/(Lag)	Weight	Weighted Exp Lead/(Lag)
2,653.00	28/02/2007	City of Mississauga Interim Billing (Argentia)	182.50	(306.00)	(123.50)	0.003	(0.39)
2,742.25	21/06/2007	City of Mississauga Final Billing (Argentia)	182.50	(193.00)	(10.50)	0.003	(0.03)
125,576.00	01/03/2007	City of Mississauga Interim Billing	182.50	(305.00)	(122.50)	0.149	(18.31)
125,501.00	05/04/2007	City of Mississauga Interim Billing	182.50	(270.00)	(87.50)	0.149	(13.07)
125,501.00	03/05/2007	City of Mississauga Interim Billing	182.50	(242.00)	(59.50)	0.149	(8.89)
383,812.10	02/08/2007	City of Mississauga Final Billing	182.50	(151.00)	31.50	0.457	14.39
4,722.00	30/01/2007	City of Brampton Interim Billing	182.50	(335.00)	(152.50)	0.006	(0.86)
4,949.43	19/07/2007	City of Brampton Final Billing	182.50	(165.00)	17.50	0.006	0.10
31,774.30	30/03/2007	Ontario Electricity Financial Interim Billing	182.50	(276.00)	(93.50)	0.038	(3.54)
32,814.03	16/10/2007	Ontario Electricity Financial Final Billing	182.50	(76.00)	106.50	0.039	4.16
AVERAGE WEIGHTED EXPENSE LAG TIME:							**(26.44)**

Source: Enersource Hydro Mississauga

D. Corporate Credit Card

The corporate credit card billing cycle begins on the 21st of the month to the 21st of the following month, if the 21st falls on a business day; otherwise, the billing cycle will fall on the following business day. Payments are withdrawn from the bank in the first week of the month following the end of the billing cycle. Based on this information, an expense lead time of 29.76 was calculated for amounts paid in 2007.

Table 13: Expense Lead Time for Corporate Credit Card in 2007

2007	Amount ($)	Cycle Start Date	Cycle End Date	Pmt Date	Service Lead Time	Pmt Lead Time	Total Lead Time	Weight Factor	Exp Time Lead
January	[redacted]	21/12/2006	22/01/2007	06/02/2007	16.50	15.00	31.50	7%	2.17
February	[redacted]	23/01/2007	20/02/2007	07/03/2007	14.50	15.00	29.50	9%	2.62
March	[redacted]	21/02/2007	20/03/2007	03/04/2007	14.00	14.00	28.00	9%	2.50
April	[redacted]	21/03/2007	20/04/2007	04/05/2007	15.50	14.00	29.50	10%	2.88
May	[redacted]	21/04/2007	22/05/2007	05/06/2007	16.00	14.00	30.00	10%	2.93
June	[redacted]	23/05/2007	21/06/2007	04/07/2007	15.00	13.00	28.00	8%	2.37
July	[redacted]	22/06/2007	20/07/2007	06/08/2007	14.50	17.00	31.50	7%	2.17
August	[redacted]	21/07/2007	20/08/2007	04/09/2007	15.50	15.00	30.50	5%	1.63
September	[redacted]	21/08/2007	20/09/2007	04/10/2007	15.50	14.00	29.50	7%	2.06
October	[redacted]	21/09/2007	22/10/2007	06/11/2007	16.00	15.00	31.00	12%	3.64
November	[redacted]	23/10/2007	21/11/2007	05/12/2007	15.00	14.00	29.00	7%	1.99
December	[redacted]	22/11/2007	20/12/2007	04/01/2008	14.50	15.00	29.50	9%	2.80
AVERAGE WEIGHTED EXPENSE LEAD TIME:									**29.76**

Source: Enersource Hydro Mississauga

E. Other OM&A

A sample of invoices from regular vendors was taken and used to determine a proxy expense lead time of 38.73 days.

F. Total OM&A

Total OM&A including payroll and benefits, consulting and contract staff, property taxes, corporate credit card and miscellaneous OM&A lead to an overall 9.73 days of expense lead time for data pertaining to 2007.

Table 14: Total Expense Lead Time for all OM & A in 2007

OM&A Category	Amount ($)	Weight	Expense Lead/(Lag)	Weighted Exp Lead/(Lag)
Payroll	32,849,580.05	0.7362	7.15	5.27
Benefits	1,708,435.09	0.0383	-5.02	-0.19
WSIB	197,718.99	0.0044	34.33	0.15
Consulting & Contract Staff	3,343,974.67	0.0749	3.93	0.29
Property Taxes	840,045.11	0.0188	-26.44	-0.50
Credit Card	1,142,191.74	0.0256	29.76	0.76
Miscellaneous O&M	4,540,883.69	0.1018	38.73	3.94
TOTAL	**44,622,829.34**			**9.73**

Source: Enersource Hydro Mississauga

Interest on Long Term Debt:

Enersource currently has bonds outstanding of $290 million, secured by a credit agreement with Borealis Infrastructure Trust. Interest on these bonds outstanding is paid semi-annually at a rate of 6.29%. Based on semi-annual payments made in 2007, an expense lead time of 32.00 days was determined.

Table 15: Expense Lead Time for Interest on Long Term Debt in 2007

Amounts	Payment Dates	Mid-Point of Year	Payment Lead (Lag)	Weighting Factor	Weighted Lead Time
$ 9,120,500	01/05/2009	30/06/2009	(60.00)	0.50	(30.00)
$ 9,120,500	01/11/2009	30/06/2009	124.00	0.50	62.00
AVERAGE WEIGHTED EXPENSE LEAD TIME:					**32.00**

Source: Enersource Hydro Mississauga

The current bonds outstanding mature May 2011 at which point the long term debt is expected to be re-financed. Given the current economic conditions of the debt markets Enersource anticipates that the corporate bond market will require interest payments to be made on a quarterly basis. This adjustment will [redacted] the expense lead time from 32.00 days to an expense lag time of [redacted].

Table 16: Expense Lag Time for Interest on Long Term Debt for 2010

Payment Amounts	Quarter Begin	Quarter End	Mid-Point of Quarter	Payment Date	Payment Lead Based on Mid Point Method	Weight	Weighted Expense Lead Time
$ 4,560,250	01/01/2010	31/03/2010	15/02/2010	01/02/2010	[redacted]	0.25	[redacted]
$ 4,560,250	01/04/2010	30/06/2010	16/05/2010	01/05/2010	[redacted]	0.25	[redacted]
$ 4,560,250	01/07/2010	30/09/2010	16/08/2010	01/08/2010	[redacted]	0.25	[redacted]
$ 4,560,250	01/10/2010	31/12/2010	16/11/2010	01/11/2010	[redacted]	0.25	[redacted]
AVERAGE WEIGHTED EXPENSE LAG TIME:							[redacted]

Source: Enersource Hydro Mississauga

Payment in Lieu of Taxes (PILS):

Enersource makes payments in lieu of taxes to the Ontario Electricity Financial Corporation (OEFC). Tax installments are made on a monthly basis and a true-up payment is generally made in February of the following year. Based on actual

payments made in 2007, a weighted average expense lead time of 15.05 days was computed.

Table 17: Expense Lead Time for PILS in 2007

Month	Installment ($)	Pay Pd. (Start)	Pay Pd. (End)	Pmt Date	Pd. Lead Time	Pmt Lead Time	Total Lead Time	Weight	Weighted Lead Time
Jan	834,246	01/01/2007	31/01/2007	31/01/2007	15.5	0	15.5	0.062	0.96
Feb	2,710,306	01/02/2007	28/02/2007	28/02/2007	14	0	14	0.200	2.80
Mar	978,481	01/03/2007	31/03/2007	30/03/2007	15.5	0	15.5	0.072	1.12
Apr	978,481	01/04/2007	30/04/2007	30/04/2007	15	0	15	0.072	1.08
May	978,481	01/05/2007	31/05/2007	31/05/2007	15.5	0	15.5	0.072	1.12
June	982,450	01/06/2007	30/06/2007	29/06/2007	15	0	15	0.073	1.09
July	978,481	01/07/2007	31/07/2007	31/07/2007	15.5	0	15.5	0.072	1.12
Aug	1,019,756	01/08/2007	31/08/2007	31/08/2007	15.5	0	15.5	0.075	1.17
Sept	1,019,756	01/09/2007	30/09/2007	28/09/2007	15	0	15	0.075	1.13
Oct	1,019,756	01/10/2007	31/10/2007	31/10/2007	15.5	0	15.5	0.075	1.17
Nov	1,019,756	01/11/2007	30/11/2007	30/11/2007	15	0	15	0.075	1.13
Dec	1,019,756	01/12/2007	31/12/2007	31/12/2007	15.5	0	15.5	0.075	1.17
AVERAGE WEIGHTED EXPENSE LEAD TIME:									**15.05**

Source: Enersource Hydro Mississauga

Debt Retirement Charge:

Enersource collects a debt retirement charge from its customers and passes this revenue to the OEFC in monthly installments. These payments are consistently made on the 18th day of the month following the collection period. Based on actual payments made in 2007, a weighted expense lead time of 32.61 days was determined.

Table 18: Expense Lead Time for Debt Retirement Charge in 2007

Amount ($)	Pay Period (Start)	Pay Period (End)	Payment Date	Pay pd. Lead Time	Pmt Lead Time	Total Lead Time	Weight	Weighted Exp Lead
3,959,908.63	01/12/2006	31/12/2006	18/02/2007	15.5	18	33.5	0.072	2.40
4,960,146.64	01/01/2007	31/01/2007	16/02/2007	15.5	16	31.5	0.090	2.82
4,587,101.21	01/02/2007	28/02/2007	16/03/2007	14	16	30	0.083	2.49
4,667,834.21	01/03/2007	31/03/2007	18/04/2007	15.5	18	33.5	0.084	2.82
4,288,716.23	01/04/2007	30/04/2007	18/05/2007	15	18	33	0.077	2.56
4,548,727.74	01/05/2007	31/05/2007	18/06/2007	15.5	18	33.5	0.082	2.75
4,436,588.90	01/06/2007	30/06/2007	18/07/2007	15	18	33	0.080	2.64
4,820,804.45	01/07/2007	31/07/2007	17/08/2007	15.5	17	32.5	0.087	2.83
4,966,250.81	01/08/2007	31/08/2007	18/09/2007	15.5	18	33.5	0.090	3.00
4,800,853.67	01/09/2007	30/09/2007	18/10/2007	15	18	33	0.087	2.86
4,689,111.11	01/10/2007	31/10/2007	16/11/2007	15.5	16	31.5	0.085	2.67
4,650,329.58	01/11/2007	30/11/2007	18/12/2007	15	18	33	0.084	2.77
AVERAGE WEIGHTED EXPENSE LEAD TIME:								**32.61**

Source: Enersource Hydro Mississauga

Summary of Net Working Capital Requirements

Taking into consideration the revenue lag and expense leads determined by 2007 data, and applying this to Enersource's 2010 Test Year data, a working cash requirement of 13.5% was calculated as determined below.

Table 19: Calculation of Net Working Capital for 2010

2010	Revenue Lag Days	Expense Lead Days	Net Lead Days	Test Year 2010	Amounts Required ($)
EXPENSES					
Revenues					
Cost of Power	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OM&A Expenses:	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interest on LT Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Debt Retirement Charge	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Income Tax	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total				[redacted]	[redacted]
GST				[redacted]	[redacted]
				[redacted]	[redacted]
Cash Working Capital as a % of OM&A					**13.5%**

Source: Enersource Hydro Mississauga

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August 17, 2009

Mr. James Macumber and Mr. John Bonadie
Enersource Corporation
3240 Mavis Road
Missisauga, Ontario, L5C 3K1

Sent by e:mail: jbonadie@enersource.com; jmacumber@enersource.com

Dear James and John:

Navigant Consulting Inc. ("NCI") was retained by Enersource Hydro Mississauga ("EHM" or "The Company") to perform an independent review of its lead lag study supporting its request for a working capital allowance from the Ontario Energy Board ("OEB"). The purpose of this letter is to present the results our review of EHM's report on working capital requirements dated August 2009.

Based on our review, we conclude that the EHM study is:

- Complete, in terms of revenue and expense items considered.
- Consistent, in terms of methods used with other studies that have been presented before the OEB by Hydro One Networks ("HONI") and Toronto Hydro Electric System Limited ("THESL").

In addition, our review indicates that the EHM study has been conducted with rigor and diligence. Our conclusion therefore, is that the results of EHM's study are reasonable when compared with other such studies that have been accepted by the OEB.

Summary of the EHM Study dated August 2009

In its report dated August 2009, the Company has identified a working capital requirement of about $86.6 million or about 13.5% of Operations, Maintenance, and Administration ("OM&A") expenses including cost of power. The majority of this working capi-

tal requirement is driven by the Company's purchases of power from the Ontario Independent Electricity System Operator ("IESO") and the Company's expenditures on OM&A. The working capital requirement associated with the power purchases alone for instance is about 75% of the Company's total working capital requirement.

Among categories of OM&A expenses considered by EHM in its report are Payroll, Benefits, WSIB, Consulting and Contract Staff, Property Taxes, Corporate Procurement Card, and Miscellaneous OM&A. In addition to the Cost of Power and OM&A expenses, other expense or pass-through items that have been considered by the Company in its study are Interest Expense, expenses relating to the Debt Retirement Charge, Payments In Lieu of taxes ("PIL's"), and the Goods and Services Tax (or "GST").

The Company has identified that the time taken to collect revenues from customers, i.e., revenue lag, is 72.40 days. This revenue lag time is driven by the four general components of revenue lag namely service (28.75 days), billing (13.03 days), collections (29.12 days), and payment processing (1.50 days).

The Company has estimated the expense lead time associated with the two major drivers of working capital requirement, i.e., cost of power and OM&A expenses, to be 32.65 and 9.73 days respectively. Other expenses that have been considered by the Company and quantified include interest on long term debt (-14.88 days), the debt retirement charge (32.61 days), and PIL's (15.05 days). Finally, the Company reports a net working capital requirement of $1.9 million associated with time differences between collections and remittances of the GST.

Discussion

Any assessment of the working capital requirements of a firm such as EHM based on a lead-lag study would, at a minimum, require the following to be addressed:

- Completeness. The completeness of a study on working capital requirements depends on the breadth of payment and receipt items considered. The wider the breadth of items considered, the clearer the picture of the working capital requirements of a business such as EHM.
- Consistency, in terms of methodology with other such studies. As defined here, consistency would entail selecting between actual data or statutory approaches when quantifying revenue lag and expense lead times. Consistency in the use of the mid-point methodology would also be a factor to consider.
- Rigor and Diligence in the selection of data sets, validation of such data sets, and sampling methodologies.

The Company's study has considered a broad spectrum of revenue and expense items including the cost of power. Major items relating to the day to day operations of the Company (OM&A) such as payroll and benefits, consulting and contract staff related expenses, WSIB payments, property taxes, and PIL's have been included in the analysis thereby enhancing its completeness. Additionally, the Company has taken into consideration interest expense payments, debt retirement charge payments, and GST pass-through's when calculating its working capital requirements.

The expense categories are wide enough in terms of the breadth of the Company's operations. Also, the categories are either similar or identical to those considered by either HONI or THESL or both in their last working capital applications which have been accepted by the OEB.[1] We conclude therefore that the working capital study performed by EHM is **complete** in terms of items that have been considered including the two key ones, i.e., OM&A expenses and cost of power.

The Company has prudently used a combination of actual data and statutory approaches for the determination of revenue lags and/or expense lead times. The expense lead times associated with WSIB, the Corporate Procurement Card, and Miscellaneous OM&A for instance, have been calculated using actual data. The expense lead time associated with GST on the other hand, has been calculated using a statutory approach, i.e., GST payments or receipts are due on the last day of the month following the date on an invoice. Also, it has been consistent in its use of the mid-point methodology to derive, where applicable, revenue lags and expense lead times. In fact, the methods used in the EHM study are, for practical purposes, identical to and therefore, consistent with those used in the OEB's accepted working capital studies of both HONI and THESL. We conclude therefore that EHM's study is **consistent,** in terms of methodology, with current practice for electricity distributors in the province of Ontario.

In our iterative review process with EHM, we observe that the Company has been **rigorous** and **diligent** in terms of the time period selected, data utilized, validation of such data, grouping of the data into the various categories under OM&A, and its choice of sampling techniques that are necessary to perform studies of this nature. While there might be subtle differences driven by the relative size of the companies and thus the nature and scope of their operations, the level of rigor and diligence used by EHM is comparable with that employed by either HONI or THESL

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[1] See Cases EB-2005-0378 and EB-2007-0680. Also see case EB-2005-0501.

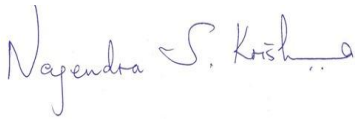
Finally, in terms of the results of the study, we note that EHM's revenue lag time is similar to that identified by both HONI and THESL in their last working capital applications accepted by the OEB. EHM's revenue lag time of 72.4 days, while slightly higher on account of known adjustments made by the Company and discussed further in the Company's report, is generally consistent with that identified in the HONI (68.41 days) and THESL (71.53 days).

As mentioned earlier, the major expense driver of working capital is the cost of power. EHM's expense lead time associated with the cost of power, i.e., 32.65 days, seems almost identical to that reported by HONI (32.46 days) and THESL (32.61 days) in their last OEB accepted working capital applications. We note further that the cost of power as a percent of total working capital requirement is similar between HONI (approx. 70%), THESL (approx.79%), and EHM (approx. 75%).

For the various reasons discussed above, we conclude that EHM's request for working capital, i.e., 13.5% of OM&A expenses including the cost of power, is **reasonable**.

John and James, it has been our pleasure to support EHM on this important project. Please let us know if you require our assistance on similar endeavors in the future.

Sincerely,



Nagendra ("Subba") Subbakrishna
Associate Director

cc. Todd Williams, NCI

Capital Expenditures Overview

This section provides a summary of capital expenditures for the historical years (2008-2011), the Bridge Year (2012), the Test Year (2013) and the incremental capital and return year (2014). The explanation of variances for these years, including the actual 2008 results compared to 2008 Board-approved, has been also included in this section.

Exhibit 2 Tab 1 Schedule 1 Appendix 2-B "Fixed Asset Continuity Schedule" provides the detailed movements for additions, customer contributions and construction in progress ("CIP") balances for each year. Please note that Appendix 2-B fulfills the requirements of the Board's suggested Appendix 2-A "Capital Projects Table".

The following table shows total capital expenditures from 2008 Board-approved to 2014 forecast and the reconciliation between these expenditures and net capital additions as presented in Exhibit 2 Tab 1 Schedule 1 Appendix 2-B for each year.

Table 1: Net Capital Expenditures, 2008 - 2014 ($000s)

Description	2008 Board Approved	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 MIFRS	2012 MIFRS	2013 MIFRS	2014 MIFRS
Land and Buildings	$ 2,500	$ 1,284	$ 491	$ 1,518	$ 2,664	$ 22,088	$ 9,196	$ 4,432
TS Primary Above 50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Station	$ 3,389	$ 4,670	$ 7,875	$ 3,854	$ 7,959	$ 6,500	$ 3,125	$ 3,349
Poles, Wires	$ 28,543	$ 31,030	$ 23,588	$ 39,145	$ 24,581	$ 22,168	$ 22,692	$ 24,851
Line Transformers	$ -	$ 548	$ 386	$ 33	$ 3,472	$ 3,166	$ 3,116	$ 3,280
Services and Meters	$ 2,008	$ 8,325	$ 10,367	$ 9,149	$ 2,650	$ 3,647	$ 1,950	$ 2,493
General Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Equipment	$ 4,158	$ 2,291	$ 3,456	$ 1,675	$ 2,283	$ 2,831	$ 3,165	$ 3,646
IT Assets	$ 12,989	$ 2,057	$ 13,981	$ 2,774	$ 5,425	$ 5,146	$ 4,092	$ 4,123
Other Distribution Assets	$ 1,379	$ 1,047	$ 2,160	$ 1,063	$ 1,259	$ 1,404	$ 1,769	$ 2,138
CIP including CIAC	$ (4,000)	$ 7,136	$ (10,391)	$ 3,553	$ (3,780)	$ (101)	$ -	$ -
Customer Contributions capitali	$ (3,750)	$ (7,651)	$ 6,399	$ (10,050)	$ (4,353)	$ (2,907)	$ (2,933)	$ (2,960)
Net Capital Expenditures	**$ 47,215**	**$ 50,737**	**$ 58,310**	**$ 52,714**	**$ 42,159**	**$ 63,942**	**$ 46,173**	**$ 45,351**
Plus AFUDC/ Borrowing cost	$ 302	$ 766	$ 1,031	$ 314	$ 403	$ 544	$ 274	$ 273
Net Capital Additions	**$ 47,517**	**$ 51,503**	**$ 59,342**	**$ 53,028**	**$ 42,563**	**$ 64,486**	**$ 46,446**	**$ 45,624**

The capital expenditures proposed for 2012 to 2014 represent investments that will continue to support the long-term needs of the distribution system and will benefit ratepayers and the community for many years to come.

The capital budgeting process begins with the completion of an Asset Management Plan ("AMP"). The AMP evaluates all distribution assets and provides recommendations on the timing of asset replacement, taking into consideration various factors such as asset condition, age, criticality, reliability information, as well as environmental, regulatory and customer impacts.

Initially a list of programs is created for each asset class for the next five years.

Once each class is evaluated, a list of projects for each major investment category is created describing the driver, scope, cost, and benefits of the project. The overall list of projects is evaluated against corporate objectives, and each project is examined according to its cost and benefit analysis when applicable.

Projects are selected and prioritized balancing requirements such as capacity requirements, service quality and customer requirements with strategic objectives of the company.

As a part of the planning process, risk evaluations are completed for each asset class that identifies the impact of the project to the community and worker safety, economics and service quality risks, environmental, regulatory, reputation and legal risks, as well as evaluating the consequences of not proceeding with the capital investment.

The objective of this whole process is to select the projects that deliver and support the required functions at the desired level of performance, that are sustainable for the foreseeable future, and that also stay within the targeted levels of operational and financial risk.

Enersource's capital budget is organized into these major investment categories:

- System Capacity – Growth Driven Investment;
- System Sustainment – Reliability Driven Investment;
- System Expansion and Upgrades – Customer Driven Investment;
- Non-System Requirements – Regulatory Driven Investment; and
- Non-System Requirements – Internally Driven Investment.

Each of these major investment categories is comprised of individual capital projects and programs as illustrated in Table 2 below.

Table 2: Capital Budget Investment Categories, Programs and Projects

Major Investment Categories	Capital Budget Programs & Projects
System Capacity - Growth Driven Investment	Subtransmission/ Distribution
	Substation Construction
System Maintenance - Reliability Driven Investment	Subdivision Rebuilds
	O/H Distribution Upgrades
	U/G Distribution Maintenance
	Transformer Replacement
	Protection & Control Upgrades (Scada)
System Expansion & Upgrades - Customer Driven Investment	Industrial/ Commercial Services
	New Subdivisions
	Road Projects
	Metering Equipment
	Smart Metering In New Condos
Non - System Requirements - Regulatory Driven Investment	Conservation & Demand
	FIT & MicroFIT Projects
	Wholesale Meter Upgrades
	Smart Metering
Non - System Requirements - Internally Driven Investment	Rolling Stock
	Major Tools
	Information Technology
	JDE ERP System
	Meter To Cash (CIS)
	Engineering & Asset Systems
	Building Addition
	Grounds & Buildings

Table 3 below outlines the overall capital expenditures for each of the major investment categories from 2007 to 2014, including the 2008 Board-approved capital expenditures.

Table 3: Total Capital Expenditures by Major Investment Category, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
System Capacity – Growth Driven Investment	$ 9,320	$9,239	$ 10,299	$ 15,791	$ 10,207	$ 10,385	$ 9,312	$ 11,134	$ 10,329
System Systainment – Reliability Driven Investment	$ 13,457	$12,795	$ 15,790	$ 19,291	$ 16,316	$ 12,707	$ 14,483	$ 16,326	$ 18,329
System Expansion & Upgrades – Customer Driven Investment	$ 6,537	$9,389	$ 6,888	$ 5,363	$ 11,899	$ 6,269	$ 6,274	$ 5,342	$ 5,749
Non-System Requirements - Regulatory Driven Investment	$ 8,279	$145	$ 6,157	$ 9,410	$ 8,763	$ 3,747	$ 4,401	$ 183	$ 219
Non-System Requirements – Internally-Driven Investment	$ 8,588	$15,647	$ 11,603	$ 8,456	$ 5,530	$ 9,052	$ 29,472	$ 13,187	$ 10,725
Total Capital Expenditures	**$ 46,180**	**$47,215**	**$ 50,737**	**$ 58,310**	**$ 52,714**	**$ 42,159**	**$ 63,942**	**$ 46,173**	**$ 45,351**

Tables 4 to 8 below outline the capital expenditures for each individual major investment category from 2007 to 2014, including the 2008 Board-approved capital expenditures.

Table 4: System Capacity – Growth Driven Investments, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
Subtransmission and Distribution	$ 5,358	$5,850	$ 4,584	$ 8,290	$ 3,515	$ 4,735	$ 4,010	$ 5,832	$ 4,545
Municipal Substation Construction & Upgrades	$ 3,962	$3,389	$ 5,714	$ 7,500	$ 6,692	$ 5,650	$ 5,302	$ 5,302	$ 5,784
Total	**$ 9,320**	**$9,239**	**$ 10,299**	**$ 15,791**	**$ 10,207**	**$ 10,385**	**$ 9,312**	**$ 11,134**	**$ 10,329**

Table 5: System Sustainment – Reliability Driven Investments, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
Subdivision Rebuilds	$ 5,972	$5,967	$ 7,669	$ 8,354	$ 7,349	$ 6,279	$ 7,356	$ 7,847	$ 8,828
Overhead Distribution Sustainment	$ 3,332	$2,600	$ 3,531	$ 4,704	$ 3,799	$ 1,676	$ 2,249	$ 2,727	$ 3,058
Underground Distribution Sustainment	$ 2,280	$2,200	$ 2,320	$ 2,441	$ 2,133	$ 2,332	$ 2,583	$ 2,998	$ 3,228
Transformer Replacement	$ 686	$650	$ 832	$ 2,464	$ 1,375	$ 947	$ 913	$ 1,004	$ 1,096
Automated Switches / SCADA Program	$ 1,187	$1,379	$ 1,438	$ 1,328	$ 1,660	$ 1,473	$ 1,382	$ 1,750	$ 2,119
Total	**$ 13,457**	**$12,795**	**$ 15,790**	**$ 19,291**	**$ 16,316**	**$ 12,707**	**$ 14,483**	**$ 16,326**	**$ 18,329**

Table 6: System Expansion and Upgrades – Customer Driven Investment, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2011 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
Industrial and Commercial Services	$ 5,146	$4,200	$ 2,182	$ 2,472	$ 1,576	$ 1,542	$ 1,326	$ 960	$ 960
New Subdivisions	$ 589	$2,575	$ 1,781	$ 818	$ 2,392	$ 2,398	$ 1,843	$ 1,647	$ 1,647
Road Projects	$ 1,075	$750	$ 783	$ 1,056	$ 1,308	$ 991	$ 1,176	$ 1,087	$ 999
Metering Equipment	$ (274)	$889	$ 462	$ 408	$ 729	$ 658	$ 952	$ 695	$ 760
Smart Metering in New Condos	$ -	$975	$ 1,680	$ 608	$ 735	$ 681	$ 977	$ 952	$ 1,383
Total	**$ 6,537**	**$9,389**	**$ 6,888**	**$ 5,363**	**$ 6,740**	**$ 6,269**	**$ 6,274**	**$ 5,342**	**$ 5,749**

Table 7: Non-System Requirements - Regulatory Driven Investments, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
Conservation & Demand Response	$ 396	$0	$ (22)	$ 43	$ -	$ -	$ -	$ -	$ -
Wholesale Metering	$ 509	$145	$ 75	$ 974	$ 518	$ 700	$ 2,779	$ -	$ -
Smart Metering	$ 7,374	$0	$ 6,104	$ 8,392	$ 8,184	$ 2,850	$ 1,488	$ -	$ -
Green Energy – FIT/MicroFIT	$ -	$0	$ -	$ -	$ 61	$ 197	$ 133	$ 183	$ 219
Total	**$ 8,279**	**$145**	**$ 6,157**	**$ 9,410**	**$ 8,763**	**$ 3,747**	**$ 4,401**	**$ 183**	**$ 219**

Table 8: Non-System Requirements – Internally Driven Investments, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2011 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
Engineering & Asset Systen	$ 1,860	$1,545	$ 1,587	$ 689	$ 1,022	$ 996	$ 1,145	$ 921	$ 911
Rolling Stock	$ 1,786	$1,858	$ 1,542	$ 1,993	$ 1,900	$ 1,900	$ 1,834	$ 1,975	$ 1,975
Information Technology	$ 461	$720	$ 952	$ 1,123	$ 1,219	$ 1,199	$ 1,406	$ 886	$ 698
JDE/ERP System	$ -	$0	$ -	$ -	$ 2,122	$ 2,017	$ 1,350	$ 1,547	$ 1,172
Meter to Cash (CC&B)	$ 3,276	$6,724	$ 6,001	$ 2,894	$ 948	$ 891	$ 1,134	$ 726	$ 1,312
Grounds & Buildings	$ 1,033	$4,650	$ 1,282	$ 1,537	$ 1,820	$ 1,805	$ 2,476	$ 6,933	$ 4,457
Acquisition of Administration Building							$ 19,952	$ -	$ -
Major Tools	$ 172	$150	$ 240	$ 219	$ 243	$ 243	$ 175	$ 200	$ 200
Total	**$ 8,588**	**$15,647**	**$ 11,603**	**$ 8,456**	**$ 9,274**	**$ 9,052**	**$ 29,472**	**$ 13,187**	**$ 10,725**

Exhibit 2 Tab 2 Schedule 2 Appendix 2 provides the business cases related to projects over the materiality threshold. The business case for each project includes the scope and purpose of project, business requirement, alternatives considered, impact of deferral, the total cost of the project and any applicable cost-benefit analysis.

Enersource relies on its long-standing internal control processes with respect to capital spending and project progress. Any deviations from the authorized plan are monitored closely by management. If an adjustment to the original authorization is required it is obtained through a formal review process.

Variance Analysis

- **2008 Actual vs 2008 Board-approved**

Actual capital expenditures in 2008 were $3,522 higher than the Board-approved amount mainly due to:

- $6,104 expenditure for smart metering which was part of the Board-approved smart meter funding adder for 2008 offset by $92 decrease in expenditure in other regulatory drive investments;
- $2,995 additional expenditure in reliability driven investments, mainly subdivision rebuilds;
- $1,060 additional expenditure in growth driven investments, mainly due to increased investments in municipal substation upgrades;
- $2,501 reduction in net capital expenditures for customer driven investments due to higher than forecasted customer contributions for 2008; and
- $4,043 less than budgeted expenditures for land, buildings, equipment and IT hardware and software.

- **2009 Actual vs 2008 Actual**

Capital expenditures were $7,573 higher in 2009 compared to 2008 due to:

- $5,492 increase in growth driven investments mainly due to a one-time $4,693 payment to Hydro One to build the Churchill Meadows transformer station;
- $3,501 additional expenditure in reliability and environmental driven investments including $1,209 for PCB transformer replacements;

- $2,289 higher expenditure for smart metering compared to prior year due to continuation of smart metering deployment program and $900 higher due to the wholesale metering equipment upgrades;
- The increases were offset by $3,083 less expenditures for information systems and other general plant due to the fact that the majority of costs for the CC&B implementation were incurred in 2008; and
- $1,525 reduction in net capital expenditures for customer driven investments mainly due to lower expenditures related to the individual metered suites compared to 2008.

- **2010 Actual vs 2009 Actual**

Capital expenditures were $5,596 lower in 2010 compared to 2009 due to:

- $5,583 decrease in growth driven investments mainly due to the prior year payment to Hydro One to build a transformer station and lower expenditures in municipal substation upgrades;
- $2,975 less expenditures in reliability driven investments such as subdivision rebuilds and overhead/underground distribution system asset replacements;
- $6,536 increase net capital expenditures for customer driven investments mainly due to final costing of new subdivisions and increased expenditures due to city and region work plans; and
- $3,573 decrease in expenditures on information systems hardware and software, grounds, buildings, fleet, smart metering and wholesale metering due to the significant investments in these categories in the prior year.

- **2011 Actual vs 2010 Actual**

Capital expenditures were $10,555 lower in 2011 compared to 2010 mainly due to:

- $2,525 decrease due to transition to MIFRS impact (non-capitalization of overhead costs);
- $5,159 less net capital expenditures for customer driven investments mainly due to the decrease in demand for these investments;
- $1,953 less expenditures in reliability driven and growth driven investments;
- $4,663 decrease in regulatory driven investments mainly due to winding down of the smart meter deployment project;
- $2,180 increase in information systems mainly due to the JDE upgrade; and
- $1,564 increase in investments in fleet, grounds and buildings and other general equipment.

- **2012 Bridge Year Forecast vs 2011 Actual**

Capital expenditures are projected to be $21,783 higher in 2012 compared to 2011 due to:

- $20,420 increase in land, buildings and grounds investments mainly due to the purchase and retrofit of a new administration building;
- $645 increase in overall expenditures in reliability driven, customer driven and growth driven investments;
- $2,080 increase in expenditures due to higher investments in wholesale meter upgrades related to the timing of Hydro One investment; and

- Offsetting the increases is the $1,362 decrease in smart metering due to the winding down of the smart meter deployment project in 2012.

- **2013 Test Year Forecast vs 2012 Bridge Year Forecast**

Capital expenditures are projected to be $17,770 lower in 2013 compared to 2012 due to:

- $19,952 decrease in expenditures due to the new building purchase in the prior year offset by $4,457 increase for improvements to the operations facility and other general equipment;
- $2,779 less expenditures in wholesale metering due to the significant expenditures in this category in the prior year;
- $1,822 increase in expenditures related to growth driven investments mainly due to the purchase of a $2,000 easement required for Churchill Meadows TS Egress Feeders project;
- $1,843 increase in expenditures related to reliability driven investments as a result of higher forecasted replacements of distribution system assets as recommended by the AMP;
- $1,439 decrease in smart metering expenditures due to expected completion of the smart meter deployment project;
- $932 less net capital expenditures for customer driven investments mainly due to the decrease in demand for these investments; and
- $789 decrease in expenditures in information systems and other general equipment mainly due to the completion of major IT initiatives.

- **2014 Forecast vs 2013 Test Year Forecast**

Capital expenditures are projected to be $821 lower in 2014 compared to 2013 due to:

- $805 decrease in expenditures related to growth driven investments mainly due to the forecasted purchase of a $2,000 easement in the prior year;
- $2,002 increase in expenditures related to reliability driven investments as a result of higher forecasted replacements of distribution system assets as recommended by the AMP; and
- $2,019 decrease mainly in facilities investments due to significant expenditures in this category in the prior year.

Capitalization Policy

Exhibit 2 Tab 2 Schedule 1 Appendix 1 is the Enersource capitalization policy document which outlines the specific criteria used to capitalize or expense expenditures in a particular period. This policy applies to all assets purchased or self-constructed and it follows the IFRS rules for capitalization. Changes to Enersource's capitalization policy due to the transition to IFRS are discussed fully at Exhibit 2 Tab 1 Schedule 1.

Internal Capital and Operating Expenditures Guidelines

This exhibit describes the accounting policies, accounting treatment and the appropriate classification of expenditures of Enersource. In addition, this exhibit describes the process and criteria used for determining if expenditures should be capitalized on the Statement of Financial Position or expensed to operations in the period incurred.

Expenditures are capitalized if they are expected to provide future economic benefits for more than one year. Any expenditure associated with the acquisition, construction, development, or betterment of an asset should be capitalized and allocated over the useful life of the asset in the form of amortization or depreciation/amortization expense.

Guidelines:

***Tangible* Assets**

Property, plant and equipment ("PPE") are identified as tangible assets provided that they are:

- held for use in the production or supply of goods and services;
- intended for a continuing use; and
- not intended for sale in the ordinary course of business.

These are assets comprised primarily of "distribution plant" and "general plant" used to distribute electricity, and include any system, structures, equipment, or other assets used for that purpose.

Intangible Assets

An intangible asset is an asset that lacks physical substance. The value is represented by business rights which give some operating, financial or income producing advantages to the Company. Examples include land rights, easements, computer software, and licenses.

Capital Assets

Capital assets include tangible and intangible assets.

Enersource's Capitalization Criteria

An item will only be capitalized when the cost of the item can be reliably measured and it is probable that future economic benefits associated with the item will flow to Enersource. Generally this means that only the costs that are directly attributable to bringing the asset to the location and condition necessary for asset to be capable of operating in the manner intended by management may be capitalized.

Capital Asset Costs

Capital assets are recorded at cost which is the amount of consideration given up to acquire, construct, develop, or better a capital asset and includes all costs directly attributable to the acquisition, construction, development, or betterment of the capital asset including installing it at the location and in the condition necessary for its intended use.

Where the item is acquired, cost of acquisition includes the purchase price and other acquisition costs such as installation costs including architectural, design and engineering fees, site preparation costs, and freight charges.

Where the item is being constructed or developed, the cost includes direct construction or development costs such as labour, materials and supplies, transportation, third party work, and other costs directly attributable to the construction or development activity.

The cost of capital assets that take a substantial period of time (over six months) to complete or get ready to use, includes an allocation of Enersource's actual general borrowing or interest costs. Capitalization of borrowing costs ceases when the asset is substantially complete and ready for productive use.

Some examples of costs that would be capitalized as Capital Assets (directly attributable) include:

- the purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
- costs of employee benefits arising directly from the labour related to the construction or acquisition of the item of property, plant and equipment;
- costs of site preparation;
- initial delivery and handling costs;
- installation and assembly costs;
- costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and
- other professional fees.

Some examples of costs that would not be capitalized (not directly attributable) include:

- costs of opening a new facility (for example, the costs associated with moving staff from one location to the other);
- costs of introducing a new product or service (including costs of advertising and promotional activities);
- costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
- administration and other general overhead costs.

Generally, costs incurred subsequent to the initial recognition of an asset are expensed unless the incurrence of that cost meets the recognition criteria set out above. Further details on the classification of expenditures can be found in Attachments A and B to this exhibit.

Betterment

A “betterment” is a cost which is incurred to enhance the service potential of a capital asset. Enersource’s expenditures on betterments are capitalized. This enhancement in service potential can include:

- an increase in the physical output or service capacity;
- a decrease in associated operating costs;
- an extension in the useful life of the asset; or,
- an improvement in the quality of the asset’s output.

Expenditures that meet the definition of betterment are capitalized whereas expenditures for maintenance of service potential of a capital asset are considered repairs and are expensed.

Major Inspection and Overhauls

Where a major inspection and overhaul is required to operate an item of PPE, the cost of inspection and overhaul may qualify as PPE and any carrying amount of the previous inspection and overhaul may need to be derecognized.

Repair/Expense

A repair is a cost which is incurred to maintain the service potential of a capital asset. Expenditures should be expensed in the current period if they relate to goods or services for which the benefits do not extend beyond the current fiscal period.

Materiality

Enersource does not have a materiality limit for the capitalization of assets. All expenditures that meet the definition to qualify as a capital asset are capitalized.

Amortization/Depreciation Rates

The useful lives by asset type used to determine amortization or depreciation rates currently used by Enersource under IFRS for new capital assets are provided in Attachment C of this exhibit.

Amortization is to be recognized in a rational and systematic manner, appropriate to the nature of the capital asset and its intended use by the company, to match costs to the related benefits.

Amortization rates for the first year and the last year of the life of a PPE or depreciable intangible assets, is to be calculated at 50% of the annual amortization rate.

Capital Spares/Standby Equipment

Spare transformers and other items kept as standby/back-up equipment are accounted for and recorded as capital assets since they enhance Enersource's distribution system reliability and are expected to be used for more than one period.

Attachment A

Enersource's Cost Component by Major Asset Grouping of PPE

Asset Category	Activity Description	Expenditure Type
Land	• Purchase price of the land • Professional services o Title Search o Broker's fees / Closing costs o Land Appraisals • Land Improvements • Care of grounds, snow removal, tree trimming, grass cutting	• Capitalize • Capitalize • Capitalize • Expense
Building & Fixtures – Brick, Stone, Concrete & Steel	• Purchase price of the building • Professional services o Broker's fees / Closing costs o Building Appraisals • Site Preparation • Construction cost of a new building • Direct Material Cost • Direct Labour Cost • Employee benefits cost • Direct Transportation costs • General Overhead costs	• Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Expense
Building & Fixtures – Other Construction	• Major renovation costs (increase functional use of building) o Alteration costs o Renovations costs o Direct Material Cost o Direct Transportation costs o Direct Labour Cost o Employee benefits cost o Professional services • Pavement of parking lots and yards • Fencing • HVAC replacement or major modifications • Building Electrical replacement or major modifications • Heating & Lighting upgrades • Major roof replacement • Plumbing major modifications • Re-gravel and Landscaping • Replacement of doors and windows • Minor repairs on all the above • General Overhead costs	• Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Expense • Expense
General Equipment	• Purchase of Office/Garage Equipment o Invoice price o Transportation o Installation • General Overhead costs	• Capitalize • Expense

Asset Category	Activity Description	Expenditure Type
Distribution station equipment	• Purchase & installation of High Voltage Switchgear • Purchase & installation of Power Transformers • Purchase & installation of Low Voltage Switchgear • Purchase & installation of Breakers • Installation of Cable at stations • Spare Station batteries • Spare TX, LV, HV for the station • Installation of smoke and fire detection systems • Installation of Dip Poles at stations • Underground automation Components of cost include o Direct Material cost o Direct Labour cost o Employee benefits cost o Transportation cost o Sub contractor cost • Minor repairs on all the above • Transformer Oil Testing • Inspections & servicing • General Overhead costs	• Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Expense • Expense • Expense • Expense
Fault Indicators	• Purchase & installation of Overhead Fault Indicators Components of cost include o Direct Material cost o Direct Labour cost o Employee benefits cost o Transportation cost o Sub contractor cost • General Overhead costs	• Capitalize • Expense
Wood Pole System	• Installation, replacement, upgrading and extensions of "fully dressed" concrete pole lines which include: • Concrete pole • Cross Arm • Bracket • Insulator • Anchors • Wires • Conductor • Arrester • Components of cost include • Purchase price, transportation, Duty • Direct Labour cost, Design time, Installation • Employee benefits cost • Fleet vehicle cost • Sub contractor cost • Minor repairs on all the above • Inspect and patrol overhead conductors / lines • General Overhead costs	• Capitalize • Expense • Expense • Expense

Asset Category	Activity Description	Expenditure Type
Concrete Pole System	• Installation, replacement, upgrading and extensions of "fully dressed" concrete pole lines which include: o Concrete pole o Cross Arm o Bracket o Insulator o Anchors o Wires o Conductor o Arrester Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost o Fleet vehicle cost o Sub contractor cost • Minor repairs on all the above • General Overhead costs	• Capitalize • Expense • Expense
Overhead Switches / Fuses	• Installation and replacement of overhead switches which include: o Fuse Cut-outs o Manual Overhead Switches Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost o Fleet vehicle cost o Sub contractor cost • Minor repairs on all the above • Inspect and patrol overhead conductors / lines • General Overhead costs	• Capitalize • Expense • Expense • Expense
Pole-mounted Transformer System	• Installation and replacement of Pole mounted TX system which include: o Overhead TX o Arrester Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost o Fleet vehicle cost o Sub contractor cost • Minor repairs on all the above • Inspect and patrol pole-mounted TXs • General Overhead costs	• Capitalize • Expense • Expense • Expense
Pad mounted Transformer System	• Installation and replacement of Pad-mounted TX or Vault TX Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost	• Capitalize

Asset Category	Activity Description	Expenditure Type
	o Fleet vehicle cost o Sub contractor cost • Minor repairs on all the above • Inspect, patrol, test pad-mounted TXs • General Overhead costs	 • Expense • Expense • Expense
Air Insulated switchgear	• Installation and replacement of Air Insulated Switchgear which include: o Switchgear o Junction Cubicle o Metal Enclosed Switchgear o Metal Enclosed Cut-out Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost o Fleet vehicle cost o Sub contractor cost • Repair & Maintenance of switchgear • Inspect, patrol, test Switchgear • General Overhead costs	• Capitalize • Expense • Expense • Expense
Solid Dielectric Switchgear	• Installation and replacement of Solid Dielectric Switchgear which include: o Solid Dielectric Switchgear o Junction Cubicle o Metal Enclosed Switchgear o Metal Enclosed Cut-out Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost o Fleet vehicle cost o Sub contractor cost • Repair & Maintenance of switchgear • Inspect, patrol and test Switchgear • General Overhead costs	• Capitalize • Expense • Expense • Expense
Underground Cable System	• Installation of UG distribution system which includes: o UG primary Cables o Termination o Arrester o UG Secondary Cable Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost o Fleet vehicle cost o Sub contractor cost • Repair & Maintenance of Cable • General Overhead costs	• Capitalize

Asset Category	Activity Description	Expenditure Type
	• Testing cable • General Overhead costs	• Expense • Expense • Expense • Expense
Duct & Foundations	o Construction of Duct banks and TX and Switchgear foundations Components of cost include o Purchase price, transportation, Duty o Direct Labour cost, Design time, Installation o Employee benefits cost o Fleet vehicle cost o Sub contractor cost • Repair & Maintenance of ducts & Foundations • General Overhead costs	• Capitalize • Expense • Expense
Underground Accessories	• Purchase & installation of Underground Accessories which include o Elbows and Inserts o Arrestors o UG fault Indicators Components of cost include o Direct Material cost o Direct Labour cost o Employee benefits cost o Transportation cost o Sub contractor cost • General Overhead costs	• Capitalize • Expense
SCADA/Protection and DC Systems	• Purchase & installation of SCADA and DC Systems which include: o Classic SCADA o SCADAMATE Motor o RTU o Batteries o Charger o Protection system/Relays Components of cost include o Direct Material cost o Direct Labour cost o Employee benefits cost o Transportation cost o Sub contractor cost • Repair & Maintenance of all the above • General Overhead costs	• Capitalize • Expense • Expense
Scadamate/ Reclosures	• Purchase & installation of Scadamate & Reclosures which include: o Local Motorized OH Switches o Reclosures o Breakers o RTU Components of cost include	• Capitalize

Asset Category	Activity Description	Expenditure Type
	o Direct Material cost o Direct Labour cost o Employee benefits cost o Transportation cost o Sub contractor cost • Repair & Maintenance of all the above • General Overhead costs	 • Expense • Expense
Meters	• Purchase & installation of meters which include: o Conventional meters o Wholesale Meters o Smart Meters o Meter Boards and Boxes o Meters Switches and Cut-outs Components of cost include o Direct Material cost o Direct Labour cost o Employee benefits cost o Transportation cost o Inspection fees and testing of brand new meters o Sub contractor cost • Disconnecting, reconnecting, removing and reinstalling, sealing and unsealing meters in connection with initiating and terminating service. • Changing or relocating meters • Inspecting or testing meters • Repair & Maintenance of meters • General Overhead costs	• Capitalize • Expense • Expense • Expense • Expense • Expense
Rolling stock	• Purchase of Rolling stock which includes: o Automobiles o Pick-up Trucks and Vans o Single Buckets, Dump trucks & Cranes o Double Buckets & RBDs o Trailers & Off Road Equipment Components of cost include o Purchase price of the vehicle o Vehicle Customization Costs o Freight charges o Duty o Sub contractor cost o Vehicle preparation costs, decals, first aid kit etc. o Major overhaul of vehicle • Maintenance, tune-up, new tires, repairs, painting etc • General Overhead costs	• Capitalize • Expense • Expense
Computer hardware	• Purchase and Installation of Computer hardware which include: o Desktops hardware and peripherals o Laptops hardware and peripherals o Security Servers & Infrastructure o Networking and Printing	• Capitalize

Asset Category	Activity Description	Expenditure Type
	o Corporate/Enterprise Hardware & Infrastructure o CPU and Memory upgrades o Data servers o Printers & other peripherals o Telephone and wireless equipment o Data communication equipment Components of cost include o Purchase price of the equipment o Customization Costs o Freight charges o Duty o Sub contractor cost • Computer Maintenance • General Overhead costs	• Expense • Expense
Major Tools	• Purchase of Major Tools used in construction activities and include equipment such as: o Air compressors o Machine and pneumatic tools o Ladders o Backhoe machines o Hydraulic Power Pack Components of cost include o Purchase price of the equipment o Freight charges o Duty o Sub contractor cost • Maintenance & repairs of all the above • General Overhead costs	• Capitalize • Expense • Expense

Attachment B

Enersource's Cost Component by Major Grouping of Intangible Assets

1 Externally Acquired Intangible Assets

Project Activity	Activity Description	Expenditure Type
Externally purchased off-the shelf software	• Purchased software • Software licenses, that allow the use of the software for the estimated useful life of the software itself (more than 12 months) • Software installation costs • Training costs • Maintenance fees • Evaluation and assessment costs	• Capitalize • Capitalize • Capitalize • Expense • Expense • Expense
Easements	• Purchase price • Legal Cost • Registration Fees	• Capitalize • Capitalize • Capitalize

2 Internally Developed Intangible Assets – Research Phase

Project Activity	Activity Description	Expenditure Type
Initiation Stage (Scope, Evaluation, Business case)	Initiation Stage Includes: • Formulation & evaluation of Alternatives • Technology evaluation; • Selection of alternatives; • Business case analysis and the management and planning functions for the project;	Expense

1 Internally Developed Intangible Assets – Development Phase

Project Activity	Activity Description	Expenditure Type
Analysis, Design and Development	• Detailed analysis of user requirements • Detailed design and specification • Software development configuration and interfaces (including total staff costs and contractor / consultant fees) • Coding • Installation of software	• Capitalize • Capitalize • Capitalize • Capitalize • Capitalize
Testing production and Implementation	• Testing including parallel processing phase up to the point where the system is live • Data conversions from the old software to the new software. • Implementation of the software	• Capitalize • Capitalize • Capitalize
Enhancement of existing applications	• Detailed design and specification • Software configuration • Development of interfaces • Coding • Installation of software • Testing including parallel processing and data conversion from old software to the new one.	• Capitalize • Capitalize • Capitalize • Capitalize • Capitalize • Capitalize
Recurring maintenance and Infrastructure support	• Recurring data refresh from old systems into the new system or between environments after the software is up and running live. • Post implementation review • Training of staff in the use or administration of the software (training room set up, organising, delivering and, attending training, fees paid to vendor to attend a training course) • Ongoing support and system administration • Applications maintenance, including annual software licences • General management of infrastructure resources and cost of infrastructure support	• Expense • Expense • Expense • Expense • Expense • Expense
Total Project, Multi-Stage or other	• Borrowing costs on qualifying assets (see IAS 23 paper for the definition of a qualifying asset)	• Capitalize

Project Activity	Activity Description	Expenditure Type
Items	• Travel costs directly related to the development and implementation • Training staff in the use of the project specific tools required to build or configure the software or hardware during a project • Development of training material and training costs relating to the use of the new software. • Any vendor ongoing support costs • Ongoing programming support to correct defects or cater for changes in legislation or modified business rules that do not constitute a significant enhancement to the software	• Capitalize • Capitalize • Expense • Expense • Expense

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Attachment C

Asset Components and Useful Lives

Asset Category	Enersource Useful Life (years)
Air Insulated switchgear	25
Building & Fixtures – Brick, Stone, Concrete & Steel	60
Building & Fixtures – Other Construction	20
Computer hardware - Corporate/Enterprise	10
Computer hardware - Desktops & Laptops	3
Computer hardware - Networking & Printing	5
Concrete Pole System	55
Distribution station equipment	40
Duct & Foundations	50
Easements	n/a
Fault Indicators	10
General Equipment	˜ı
Land	n/a
Major Software - Corporate/Enterprise	10
Major Tools	10
Meters	25
Minor Software	2
Overhead Switches / Fuses	40
Pad mounted Transformer System	35
Pole-mounted Transformer System	45
Rolling stock - Automobiles	4
Rolling stock - Double Buckets & RBDs	12
Rolling stock - Pick up Trucks & Vans	5
Rolling stock - Single Buckets, Dump trucks & Cranes	8
Rolling stock - Trailers & Off Road Equipment	15
SCADA/Protection and DC Systems	15
Scadamate/ Reclosures	25
Smart Meters	15
Solid Dielectric Switchgear	35
System Software - Office Automation & Collaboration	5
Underground Accessories	20
Underground Cable System	40
Wholesale Meters	25
Wood Pole System	45

Asset Management Plan

Overview and Objective

Enersource has prepared an Asset Management Plan ("AMP") which is provided at Appendix 1 of this exhibit. The AMP outlines the asset management practices which are part of an optimized lifecycle strategy for Enersource's distribution system assets. The scope of the AMP encompasses programs and major projects that are required to sustain Enersource's electrical distribution system.

The objectives of the AMP are to:

- Report on the performance of the distribution system;
- Identify risks and challenges that would adversely affect the ability to deliver economically reliable power to Mississauga; and
- Present a multi-dimensional over-arching strategy and tactical plan for investing in and maintaining assets in order to effectively achieve the lowest long-term owning costs.

The AMP details how Enersource manages, maintains, and reinforces the electrical distribution system in a cost-effective manner. The AMP outlines the programs, projects, and capital expenditures for the next five years, beginning January 1, 2012. In addition, the AMP reviews the capital, operating, and reliability trends over the past five years.

In pursuit of Enersource's mission, the organization will ensure to meet legal, regulatory, and environmental compliance and strive to continuously improve overall customer satisfaction. Enersource is committed to the activities outlined in the AMP and intends to continue to build on the many successes achieved to date.

Challenges Facing the Enersource Distribution System

Managing aging infrastructure and system capacity requirements will continue to present challenges in both the short- and long-term. Enersource's distribution system assets range in age from new to over 50 years old. The management of these assets is critical to providing safe, reliable, and efficient electricity distribution services to its customers.

The AMP emphasizes a continued focus on managing the aging infrastructure, particularly in the management of poles, underground cables, distribution transformers, substation transformers, and substation switchgear. Given the large expansion of the system during the City of Mississauga's development boom years of the 1970's, 1980's, and 1990's, a considerable amount of asset replacement is expected within the next five to twenty years.

The asset replacement approach must be prudently managed, to achieve the lowest long-term owning cost of the distribution equipment while conforming to industry standards and requirements, and meeting the needs and expectations of Enersource's customers in terms of rates, performance, and reliability. This is particularly important given that a considerable portion of the expansion experienced in Mississauga's boom years was funded with significant amounts of capital contributions from developers. This will not occur as the system assets are replaced, placing significant pressures on rates.

To address the impending increase in the number of assets that are expected to reach their useful life over the next two decades, the AMP also identifies several initiatives under development and consideration to closely monitor, analyze, and evaluate asset management activities in order to refine the approach needed to meet the expected increase in replacement rates.

Information and Inputs Used to Prepare the AMP

Enersource used several sources of data to assess the status of the assets in its distribution system and to assist with determining the capital and operational investments to be made in the system. This data included, but was not limited to, an asset condition assessment, reliability information, as well as, system criticality, environmental, and customer impacts. The sources of data included:

- an Asset Condition Assessment ("ACA), prepared by Kinectrics Inc. ("Kinectrics");
- a load forecast of system capacity;
- Testing and Inspection Programs;
- Integrated Operating Model ("IOM"); and
- Automated Mapping / Facilities Management / Geographical Information System ("AM/FM/GIS").

The data was computed and analyzed using various tools and techniques to produce a priority list of projects by asset classes.

Risks need to be controlled and mitigated to support Enersource's corporate governance needs and due diligence responsibilities. The AMP includes a risk assessment that identifies and prioritizes risks associated with managing and expanding the distribution system assets. As a part of the planning process, risk evaluations were completed for each asset class.

Asset Condition Assessment

Conducting an ACA is a process whereby the condition of all key asset categories owned by Enersource is assessed. In early 2011, Enersource selected and engaged Kinectrics to complete the ACA. Kinectrics has a wide

range of experience in assessing the condition of utility assets. Enersource utilized the Kinectrics' ACA in developing the 2012 AMP.

Kinectrics provided its ACA in late-2011 which included the development of a health index (the "Health Index") for eleven asset classes, determined the Health Index distribution for the entire population of assets in each class, and developed a forty-year condition-based replacement plan. Based on Kinectrics' formulations and industry-accepted methodologies, equipment replacement rates for all of the asset classes were developed. Each is discussed in detail in the AMP.

The findings of the ACA are provided in the AMP. The ACA identified two asset groups to be of particular concern, three-phase padmounted transformers and padmounted switch gear. These asset groups were found to have 13% and 14% of the population in poor or very poor condition, respectively.

Other asset classes identified by the ACA for action include circuit breakers, single-phase padmounted transformers, and vault transformers. For each asset class, various charts are provided. Samples of these charts for one asset class, single-phase padmounted transformers, are shown below in Figures 1 and 2.

Figure 1 provides a sample age distribution of the specific asset type. Figure 2 shows the recommended replacement rates of the asset type. These figures are provided in the AMP for each asset type.

Figure 1: Single-Phase Padmounted Transformer Age Distribution

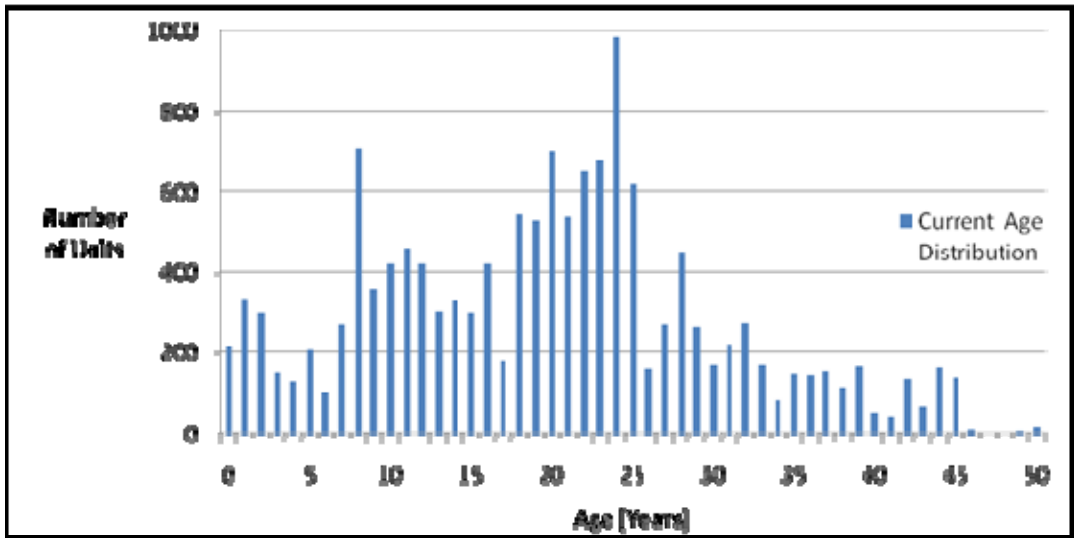
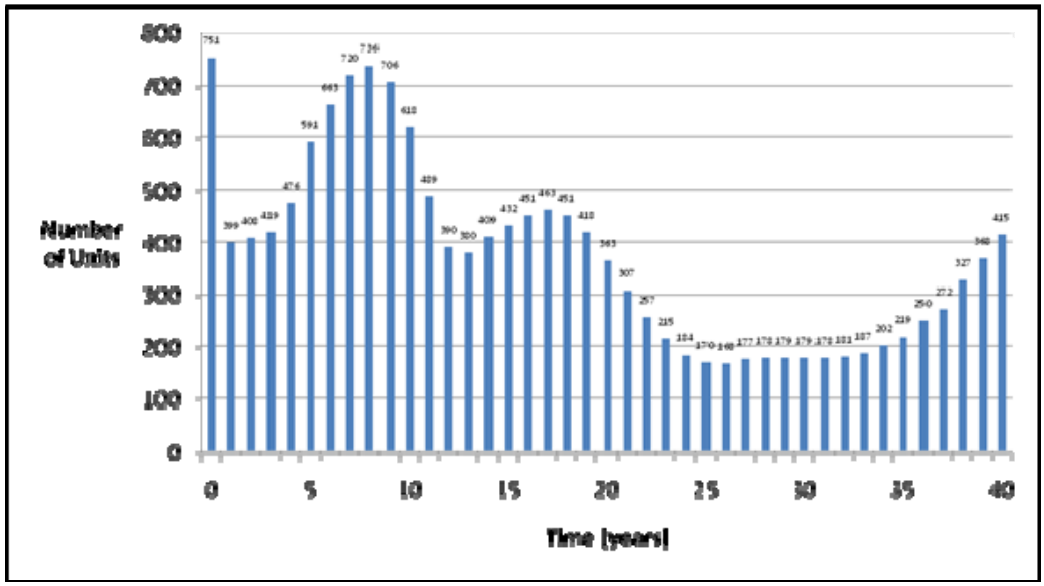


Figure 2: Single-Phase Pad Mounted Transformers - Recommended Replacement Rate



The ACA report was one of several key inputs for the AMP. It evaluated Enersource's existing programs and emphasized the immediate need for the development of new initiatives to address the required replacement rates for all

asset groups. These new initiatives are summarized below and discussed further in the AMP.

Future Planning Initiatives

Enersource will enhance its current methods and techniques with many future planning initiatives discussed in the AMP. These new initiatives will provide significant value to customers and are expected to enable Enersource to make more-informed decisions and optimize its asset decisions in order to enhance system reliability. The ultimate goals of these initiatives are to minimize long-term owning costs, and to refine the optimized lifecycle strategy for distribution system assets. Please refer to Exhibit 4 Tab1 Schedule 5 for further discussion on the operating costs associated with these asset management efforts.

The future planning initiatives discussed in detail in the AMP include:

- System Planning Software (CYMDIST);
- Transformer Loading Tool;
- Pole Testing Pilot Program;
- Ten Worst Feeder Study; and
- Major Outage Cause Study.

AMP Investment Program

A summary of the investments identified in the AMP are provided in Table 1 below. Table 1 summarizes the capital program by Enersource's five major investment categories. These five investment categories are identified and described briefly below. Further detail on the programs, projects, and costs within each category is provided within the AMP.

Overall, the AMP investment plan over the next five years is consistent with recent Enersource investment activities and suggests a continuation of programs and developments. To address the impending number of assets that are expected to reach their useful life in the near and medium terms, the AMP also identifies several initiatives under development and consideration to closely monitor, analyze, and evaluate asset management activities in order to refine the approach needed to meet the expected increase in replacement rates.

Table 1: AMP Capital Budget Expenditures, 2007 to 2016 ($000s)

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
System Capacity – Growth Driven Investment	9,320	10,299	15,791	10,207	10,385	9,312	11,134	10,329	10,507	10,686
System Systainment – Reliability Driven Investment	13,457	15,790	19,291	16,316	12,707	14,483	16,326	18,329	19,319	20,939
System Expansion & Upgrades – Customer Driven Investment	6,537	6,888	5,363	11,899	6,269	6,274	5,342	5,749	5,037	4,975
Non-System Requirements - Regulatory Driven Investment	8,279	6,157	9,410	8,763	3,747	4,401	183	219	256	293
Non-System Requirements – Internally-Driven Investment	8,588	11,603	8,456	5,530	9,052	29,472	13,187	10,725	9,646	9,317
TOTAL CAPITAL EXPEDITURES	**46,180**	**50,737**	**58,310**	**52,714**	**42,159**	**63,942**	**46,173**	**45,351**	**44,766**	**46,209**

System Capacity – Growth Driven Investment

Growth-driven capital projects ensure the continuation of Enersource's capability to provide a secure and reliable supply of electricity to its customers. Growth is predicted through the combined use of growth projections, historical growth patterns, and load forecast models.

The System Capacity – Growth Driven Investment category has two components:

- Subtransmission and Distribution Program; and
- Municipal Substation Construction and Upgrades Program.

System Sustainment – Reliability Driven Investment

Maintaining reliability is one of the key success factors of Enersource. To maintain reliability Enersource actively tracks outage causes and effects. Based on this information Enersource has ongoing rebuild, upgrade, and replacement programs.

The System Sustainment – Reliability Driven Investment category has five components:

- Subdivision Rebuilds Program;
- Overhead Distribution Sustainment;
- Underground Distribution Sustainment;
- Transformer Replacement; and
- Automated Switches / SCADA Program.

System Expansion and Upgrades – Customer Driven Investment

Customer driven investment projects are required for the connection of new customers or to modify or upgrade a customer's current service. Projects of this nature are not discretionary but mandatory, and include work such as new residential connections, industrial/commercial connections, and metering equipment upgrades and installation.

The System Expansion and Upgrades – Customer Driven Investment category has five components:

- Industrial and Commercial Services;
- New Subdivisions;
- Road Projects;
- Metering Equipment; and
- Individual Metered Suites in Condominiums.

Non-System Requirements – Regulatory Driven Investment

Regulatory driven investment projects are mandated by industry regulations. Projects of this nature include wholesale metering upgrades per IESO market rules, and OEB-sponsored initiatives such as smart metering and time-of-use rates ("TOU") and the Green Energy and Green Economy Act ("GEA").

The Non-System Requirements – Regulatory Driven Investment category has three components:

- Wholesale Metering;
- Smart Metering; and
- Green Energy and Feed-in Tariffs.

Non-System Requirements – Internally Driven Investment

The Non-System Requirements – Internally Driven Investment category has eight components:

- Engineering and Asset Systems;
- Rolling Stock;
- Information Technology;

- JDE / ERP System;
- Meter to Cash;
- Grounds and Buildings;
- Acquisition of Administration Office; and
- Major Tools.

A list of projects and expenditures for this category are provided in the AMP.

Appendix of Major Projects

An appendix accompanies the AMP which provides further detail for major projects. These details are found at Exhibit 2 Tab 2 Schedule 2 Appendix 2.

Enersource Hydro Mississauga Inc.

Asset Management Plan

2012

April 2012

Executive Summary

The objective of Enersource's asset management plan ("AMP") is to present a multi-dimensional investment strategy and plan for investing in electricity infrastructure, equipment and intangible assets required by Enersource in order to effectively fulfill and exceed customer needs and stakeholder requirements. Enersource's AMP involves a centralization of key decision making to maximize the effectiveness of investments, while maintaining performance levels. The AMP was developed on the principle of investing in and maintaining assets to achieve the lowest long-term owning costs while conforming to system design standards/requirements, construction standards/codes, system performance standards and prescribed set of manufacturing specifications.

The AMP aligns with Enersource's strategy to provide acceptable long term reliability performance of the subtransmission and distribution systems while keeping personnel, service providers and the public safe. In pursuit of Enersource's mission, the organization will ensure to meet legal, regulatory and environmental compliance and strive to continuously improve overall customer satisfaction. Enersource is committed to the activities outlined in this AMP and intends to continue to build on the many successes achieved to date.

The structure of this report was developed from the chronological activities that were undertaken in its development. To provide context of the organization and the culture, the report introduces the corporate strategy, mission and vision and brief overview of the history of the organization. Enersource's service territory and high level description of the subtransmission and distribution systems are illustrated to provide context of the topographical outline before the discussion of system performance and reliability history.

The comprehensive and balanced AMP is based on multitude of inputs including, but not limited to, asset condition assessment ("ACA"), system capacity load forecast and asset information extracted from testing and inspection reports, information from the Integrated Operating Model ("IOM") as well as the Automated Mapping/Facilities Management ("AM/FM") and Geographical Information Systems ("GIS").

The ACA was completed by Kinetrics Inc. in November 2011 in order to evaluate and determine the asset health index and to develop and report a condition-based replacement schedule for each key distribution asset group. The ACA identified that three phase pad mounted transformers and pad mounted switch gear asset groups were found to be of concern due to the number of units in poor or very poor condition, found to be at 13% and 14% of the population respectively. Other asset classes identified by the ACA for action include circuit breakers, single phase pad mounted transformers and vault transformers. Enersource has examined, evaluated and prioritized programs and projects to address these findings, analysis is summarized in ACA asset class finding section of this AMP.

It is important to note that although the ACA does reflect the benefits of Enersource's historical maintenance and sustainment practices which ensured the a good proportion of distribution system assets are currently in acceptable operational state, a large number of asset classes are expected to require replacement at increasing rates over the near and mid-term outlooks. This can be evidenced by the waves of asset populations installed during times of rapid growth in Mississauga that are soon expected to approach the end of the useful life. This AMP outlines the tactics and activities that Enersource will undertake in order to optimally address these increasing rates of replacement through proactive planning, risk evaluation and continuation of existing programs and projects outlined here within.

The methodology applied in the development of the AMP is founded on the management of key factors including system planning, prioritization and execution of capital projects and sustainment programs. The objective of these activities is to select the projects and programs that deliver the required functions at the desired sustainable level of performance. These projects and programs are classified in to categories that include requirements for capacity, service quality, customer demands and strategic initiatives. Capacity requirement investments are required to maintain and expand the distribution system in an efficient manner. Service quality requirement investments ensure that performance of the distribution system is maintained in regard to reliability, power quality and support customer value. Investments pertaining to customer requirements are required to achieve compliance standards, new connection and to promptly respond to customer inquiries. Investments regarding strategic activities include those that pursue optimal operations, effective maintenance programs and development of distribution system while minimizing the environmental impact in support of good corporate citizenship.

To improve previous system planning outlooks developed under a needs-based framework, this AMP enhances on the planning process by implementing an additional stage which includes a risk-based assessment of the asset classes. The risk assessment was completed for each asset class as it pertains to economic, service quality, regulatory/legal compliance, environmental, reputational and employee/public safety. The risk assessment results are used to aid in evaluating and prioritizing project and program planning.

Based on the multitude of inputs outlined, program activities and projects based on developed business cases and risk assessment, an investment plan was developed which underpins the near term capital budget of this AMP. The investment plan describes the major projects and outlines the ongoing programs through this period captured into investment capital categories. Overall, the investment plan presented stays consistent with previous Enersource investments activities and suggest a continuation of programs and developments. To address the impending wave increases of assets that are expected to reach the useful life in the near and medium terms, this plan also identifies several initiatives under development and consideration to closely monitor, analyze and evaluate asset management activities in order to refine the approach needed to meet the expected increases in replacement rate. These asset management and planning initiatives include utilization of additional tools such as system planning software to perform comprehensive distribution system analysis, development of a transformer loading analysis tool to monitor the loading of distribution transformers and several maintenance pilot programs such as pole testing and cable field assessment testing. Further studies such as ongoing evaluation of the worst performing feeders and enhanced analysis of major outage caused are to be further developed and incorporated in future AMP developments.

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HISTORY AND BACKGROUND INFORMATION

1. Corporate Strategy

Enersource Hydro Mississauga Inc. ("Enersource" or "the Company") has prepared a comprehensive and robust corporate strategic plan (the "Strategic Plan") that provides for asset investment initiatives with financial and operational returns on those investments. A key consideration of the Strategic Plan, and reflected within this asset management plan (the "AMP"), is the concept of balancing customer expectations with stakeholder requirements, in the most cost effective manner. This balance must consider financial, operational and regulatory constraints.

While utilities are permitted to earn a rate of return on their rate base investment, the timelines of recovery of those investments are predicated upon the expected useful lives of the asset. Therefore, Company management must ensure that appropriate funding is available to undertake those long-term investments.

Also, management must ensure that properly trained and certified workers are available to construct and maintain Enersource's assets through directly-employed staff or by utilizing subcontracting firms. As this expertise is specialized, industry competition for these resources is strong.

Enersource's Strategic Plan is validated annually and its corporate goals are translated into each employee's personal annual performance goals and objectives. Many of the strategic initiatives within the Strategic Plan have been assigned to cross functional teams thereby ensuring a successful outcome for Enersource. The focal points of the Strategic Plan include:

Business Engagement:	External Engagement:	Organizational Engagement:
• Strategic capital flexibility • Strategic investments • Revenue stabilization	• Communications enhancement • Distribution rate design • Enersource brand enhancement	• Resource development • Organizational enhancement • Health and safety • Business risk mitigation

Table 1.1: Focal Points of the Strategic Plan

Enersource's Strategic Plan is a balanced and comprehensive. Enersource remains committed to this comprehensive plan and will continue to build on the many successes achieved to date.

To complement the development of the Strategic Plan and budgets of the company, the capital plans of Enersource are assessed in a comprehensive manner and are evaluated to ensure alignment with the corporate strategies. Risk assessment is conducted on projects to help develop solutions to mitigate risks and to prioritize.

Business Outcome	Key Success Factor	Key Indicator Groups	Key Performance Indicators
System Reliability and Long Term Sustainability	Acceptable long term reliability performance of subtransmission and distribution systems	• Reliability • Maintenance costs	SAIDI SAIFI CAIDI Within Budget
Health and Safety	Keep personnel, service providers, and the public safe	• Employee safety incidents • Service provider safety incidents • Public safety incidents	Lost Time Incidents Medical Aid Injuries First Aid Injuries Vehicle Accidents Property Damage Property Theft
Legal, Regulatory, and Environmental Compliance	Meet all compliance standards	• Regulatory service quality indicators results • Legal violations • License conditions violations	Connection of New Services Appointment Scheduling Appointments Met Rescheduling a Missed Appointment Telephone Accessibility Telephone Call Abandon Rate Written Responses to Enquiries Emergency Response
Customer	Improve overall customer satisfaction	• Customer satisfaction result	Customer satisfaction survey

Table 1.2 – Enersource Business Outcomes and Success Factors

	OEB / ESA	Enersource
PERFORMANCE MEASUREMENTS	**Target**	**Target**
SAFETY:		
Number of Preventable Lost Time Injuries (If "LTI" result =1, then achieved = 10%)	N/A	0
RELIABILITY: Annual Average Outage per Customer		
OEB Requirements		
SAIDI [System Average Interruption Duration Index] Outage Minutes/Customer/year	(High 53.3), (Low 36.7)	41.10
SAIFI [System Average Interruption Frequency Index] Outage Interruptions/Customer/Year	(High 1.97), (Low 1.18)	1.41
Customer Restoration Targets:		
CAIDI [Customer Average Interruption Duration Index] Annual Average of Minutes / Interruption	(High 31.1), (Low 26.5)	36.00
SERVICE QUALITY: Electricity Service Quality Requirements (ESQRs)		
Connection of New Services		
<750 volts connected within 5 working days from the day on which all conditions of service are satisfied	90%	95%
>750 volts connected within 10 working days from the day on which all conditions of service are satisfied	90%	95%
Customer Service		
Incoming calls answered by Customer Service Representative within 30 seconds [Telephone Accessibility]	65%	80%
Incoming calls abandon by Customer [Telephone Call Abandon Rate]	≤10%	≤10%
Appointments		
Scheduled of appointments within 5 days of a customer's request	90%	90%
Appointments at customer's premises met within appointed time [am or pm]	90%	90%
Rescheduled of missed appointments within 1 day	100%	100%
Cable Locates completed within 5 working days of a customer's request (ESA)	90%	90%
Written Response to Inquiries		
Written response to inquiries from customer or agent of customer, within 9 working days following receipt of request	80%	95%
Emergency Response		
Emergency trouble calls response within 60 minutes.	80%	95%
Reconnection Standards		
Post disconnection due to non-payment, reconnect within 2 business days of full payment or arrears payment agreement	85%	85%
CONSOLIDATED PRE-TAX NET INCOME (120% OF BUDGET on Modified IFRS*)		
Pre-Tax Net Income		
Target to follow subsequent to Board approval of 2012 Budget numbers	N/A	TBD
** Modified IFRS: IFRS based net income adding back Regulatory Asset & Liability activity and settlement.*		

Table 1.3 – Enersource 2012 Corporate Performance Target

2. Corporate Mission Statement and Vision

Mission Statement

Consistently fulfill and exceed customer needs and stakeholder requirements.

Enersource Vision

To be a leading energy solution provider through integrity, innovation, teamwork and excellence.

Core Corporate Values

We conduct business in a manner that results in the reliable, safe and efficient delivery of electricity and energy solutions while ensuring environmental and fiscal integrity in our operations. These are listed, and described more fully, below:

Integrity

- we interact with customers, stakeholders, and each other honestly and respectfully
- we conduct ourselves consistently with core principles and values
- we strive to provide maximum customer and shareholder value and return on investment
- we say what we mean. We do what we say

Innovation

- we encourage open dialogue and recognize initiative and creative thinking
- we provide innovative products and service solutions

Teamwork

- we provide a healthy environment for our employees and the communities we serve
- we work together openly, honestly, and respectfully to achieve our mission

Excellence

- we protect ourselves, each other and the community from harm by operating in a safe manner, always
- we operate in a manner that inspires confidence and secures the support of all of our customers and stakeholders

3. Enersource History

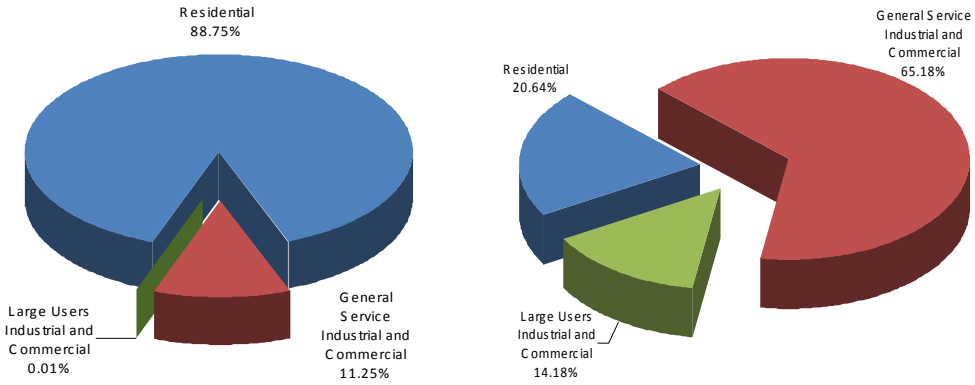
Enersource owns and operates the electricity distribution system in the city of Mississauga (the "city" or "Mississauga") and serves approximately 196,000 homes and businesses. Including Hydro One data, Enersource is the sixth largest electricity distributor by number of customers, and the fourth largest distributor by both peak load and energy consumed in the Province of Ontario. Enersource is governed by the *Electricity Act, 1998,* and regulated by the Ontario Energy Board.

Enersource is 90% owned by the city and 10% owned by BPC Energy Corporation ("Borealis"), a subsidiary of the Ontario Municipal Employees Retirement System. Enersource, or its predecessors, continue to deliver "more than energy"[1] to Mississauga residents and businesses, and have done so for almost a century.

The current city, incorporated in 1974, was formed through the amalgamation of the Town of Mississauga and the villages of Port Credit and Streetsville, together with portions of the Townships of Toronto Gore and Trafalgar.

It was a vast rural area in 1917, with farmers slowly discovering the benefits of electricity. Simple hydro and telecommunication lines appeared on the landscape linking family farms with life in the township's commercial hubs, the villages of Streetsville and Port Credit. It was in this setting, following special legislative approval, that the Toronto Township Hydro Commission was formed. That fledgling Commission later merged with the two village hydro utilities becoming Mississauga Hydro Electric Commission. In the year 2000, the new name "Enersource" emerged, associated with the commercial restructuring of the Company, introducing several Enersource affiliates including Enersource Hydro Mississauga Inc.

Enersource and its founding hydro utilities achieved many innovations over the years. From the early 1900's as the first township to contract for electricity with Ontario Hydro, to the 1950's as it began to innovate with underground distribution through residential neighbourhoods, and set records as a municipality supporting the development of 1,000 electricity heated homes.



Proportion of Accounts by Type ***Proportion of Energy Consumption***

Figure 3.1 – Proportion of Enersource's Customer Types and Energy Consumption

[1] This is Enersource's brand tagline, representing its pledge to provide customers with more than the reliable delivery of electricity but also fast, courteous service, and good community citizenship.

Enersource's territory covers 287 square kilometers which includes 1,807 km of overhead lines, 3,360 km of underground lines and approximately 25,000 distribution transformers. A map of Enersource's service territory is shown in Figure 3.2.

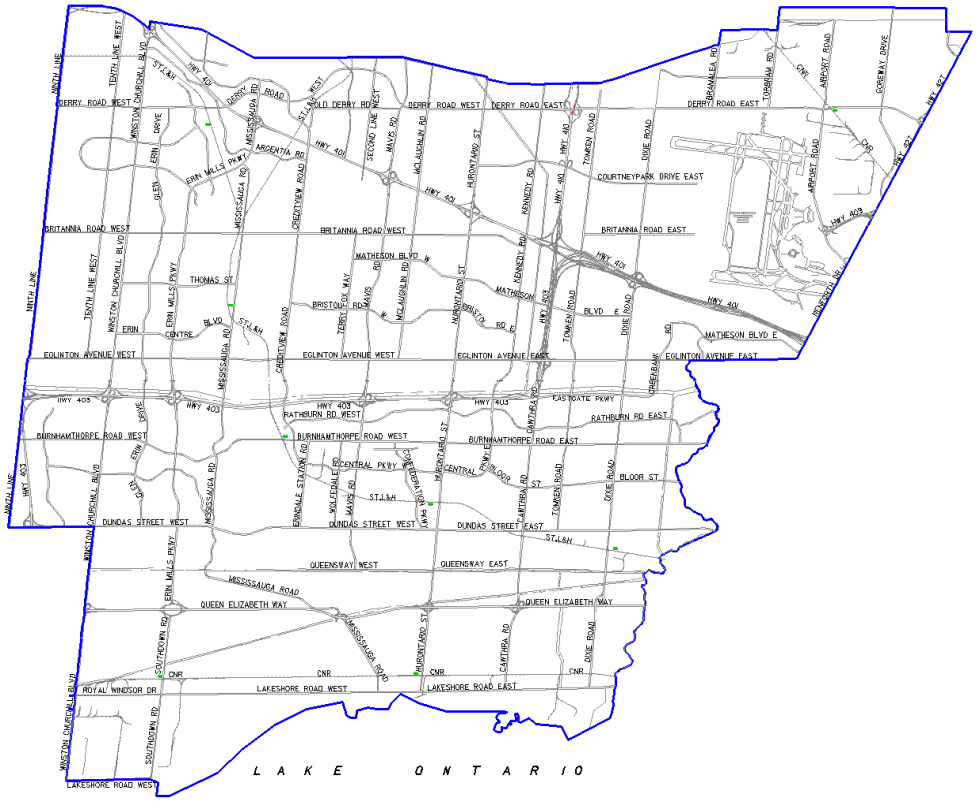


Figure 3.2 – Map of Enersource Territory

ELECTRICAL SYSTEM DESCRIPTION

4. Historical System Description

4.1 System Description

Enersource owns and operates the electrical power system in Mississauga. The system can be divided into two main categories: subtransmission and distribution.

4.1.1 Subtransmission System

Enersource's subtransmission system operates at a voltage of 44kV. The system receives electricity from Hydro One's Transformer Stations ("TS's" plural or "TS" singular) where voltage is transformed from 230kV to 44kV.

The Hydro One TS sites are: Meadowvale TS, Churchill Meadows TS, Erindale TS, Tomken TS, Bramalea TS, and Woodbridge TS. Enersource's subtransmission system is comprised of two areas: West 44kV and East 44kV, as illustrated in Figure 4.1 below.

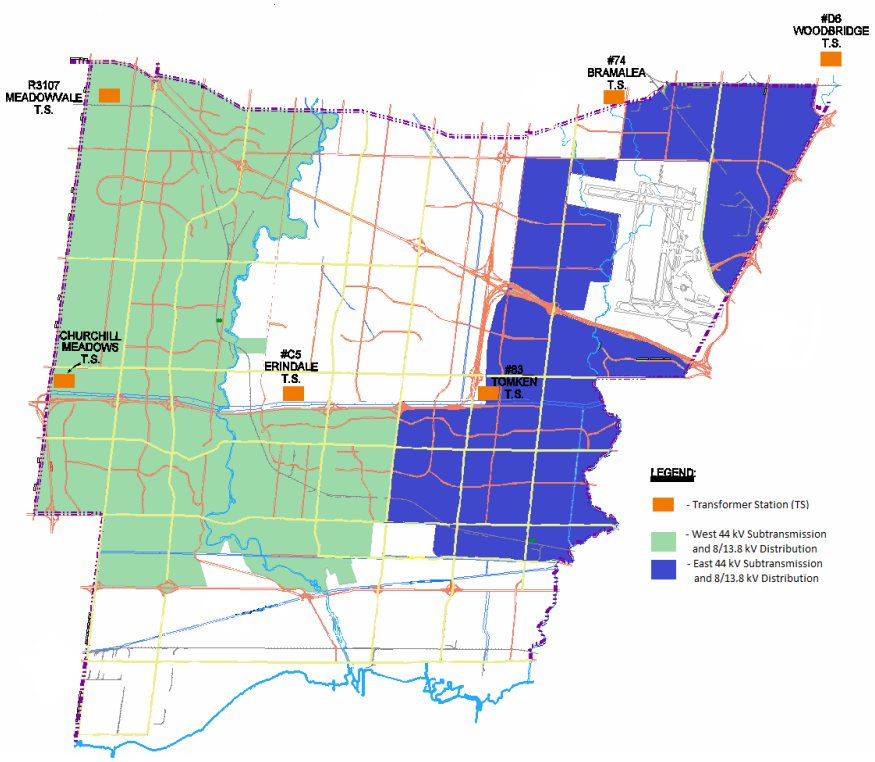


Figure 4.1 – Map of Enersource 44kV Subtransmission System

4.1.2 Distribution System

Enersource's distribution system operates at the voltages of 16/27.6kV, 8/13.8kV, and 2.4/4.16kV.

The system receives electricity from two sources: Hydro One's TS's where voltage is transformed from 230kV to 16/27.6kV, or Enersource's Municipal Stations ("MS's" plural or "MS" singular) sites where the voltage is transformed from 44kV to 8/13.8kV or from 16/27.6kV to 2.4/4.16kV

The Hydro One TS sites are: Oakville TS, Lorne Park TS, Cooksville TS, Richview TS, Erindale TS, Cardiff TS, and Bramalea TS.

Enersource supply points consist of 65 MS locations utilizing 103 power transformers that vary in capacity from 3 MVA to 20 MVA. The distribution system utilizes 58 distribution feeders.

Enersource has divided its distribution system into four areas: North 16/27.6kV, South 16/27.6kV and 2.4/4.16kV, West 8/13.8kV and East 8/13.8kV as illustrated in Figure 4.2 below.

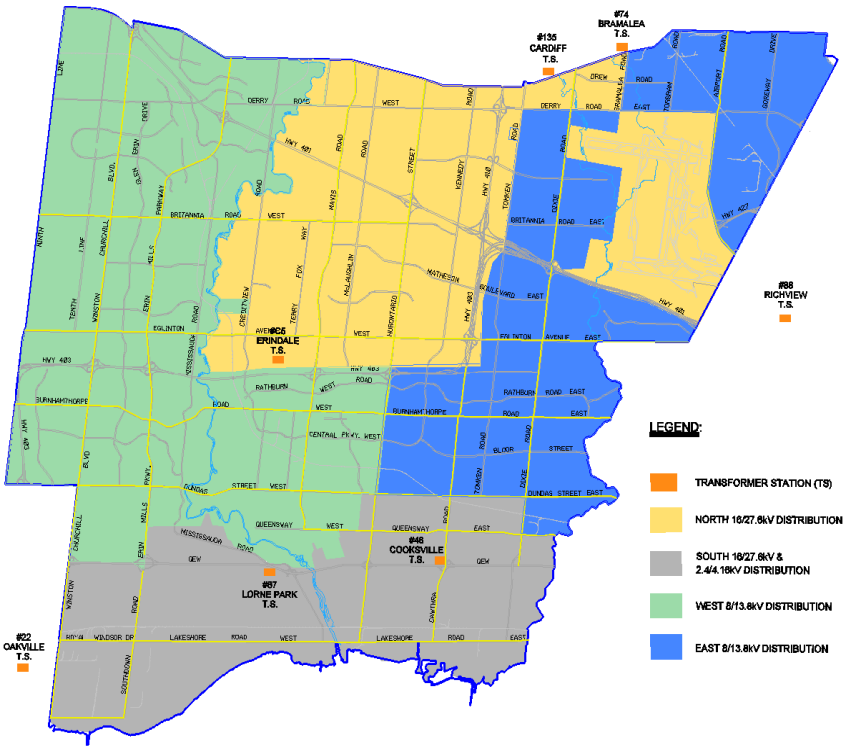


Figure 4.2 – Map of Enersource Distribution System

4.1.2.1 North 16/27.6kV Distribution System

The North 16/27.6kV System consists mainly of distribution equipment which is connected directly to Hydro One TS feeders.

Hydro One TS sites are: Erindale TS, Bramalea TS, Cardiff TS, and Richview TS.

This area contains one Enersource MS site comprised of two step-down transformers rated 44/27.6kV. The overall North 16/27.6kV distribution system utilizes 32 distribution feeders; four of which are supplied by the MS and 28 are supplied by Hydro One TS sites.

The area serviced by this system is illustrated in Figure 4.3 below.

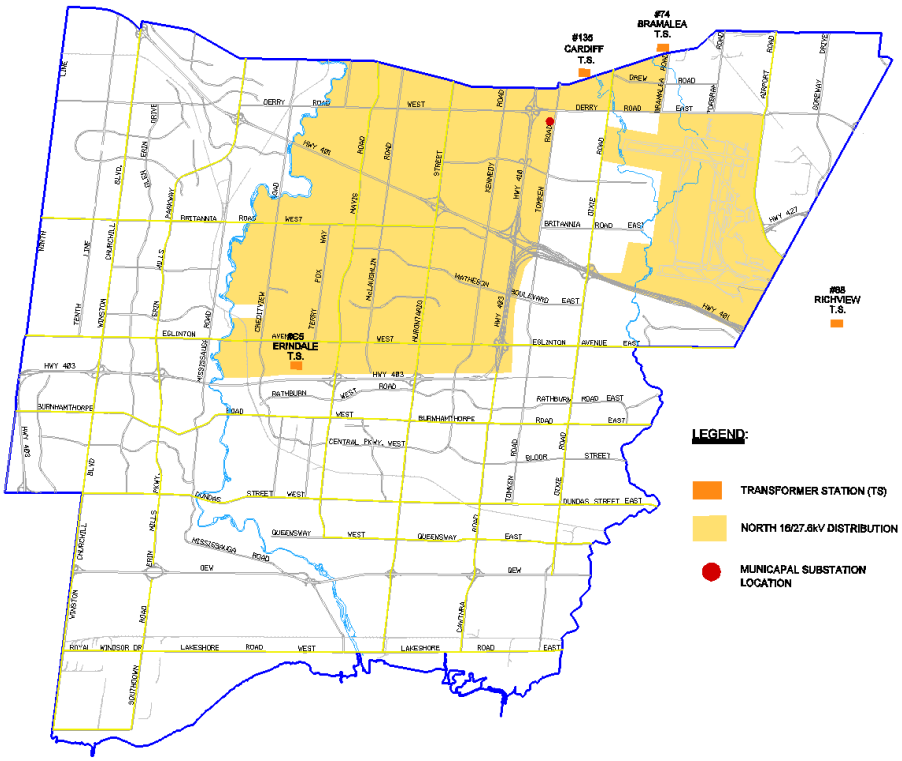


Figure 4.3 – Map of Enersource North 16/27.6kV Distribution System

4.1.2.2 South 16/27.6kV and 2.4/4.16kV Distribution System

The South 16/27.6kV System is composed of several large and small customers connected directly to Hydro One TS supply. Enersource's MS's further step down the voltage to the 2.4/4.16kV distribution system.

Hydro One TS sites are: Oakville TS, Lorne Park TS, and Cooksville TS.

This area contains 25 MS sites comprised of 38 step-down transformers rated 27.6/4.16kV. This distribution system utilizes 96 distribution feeders.

The area serviced by this system is illustrated in Figure 4.4 below.

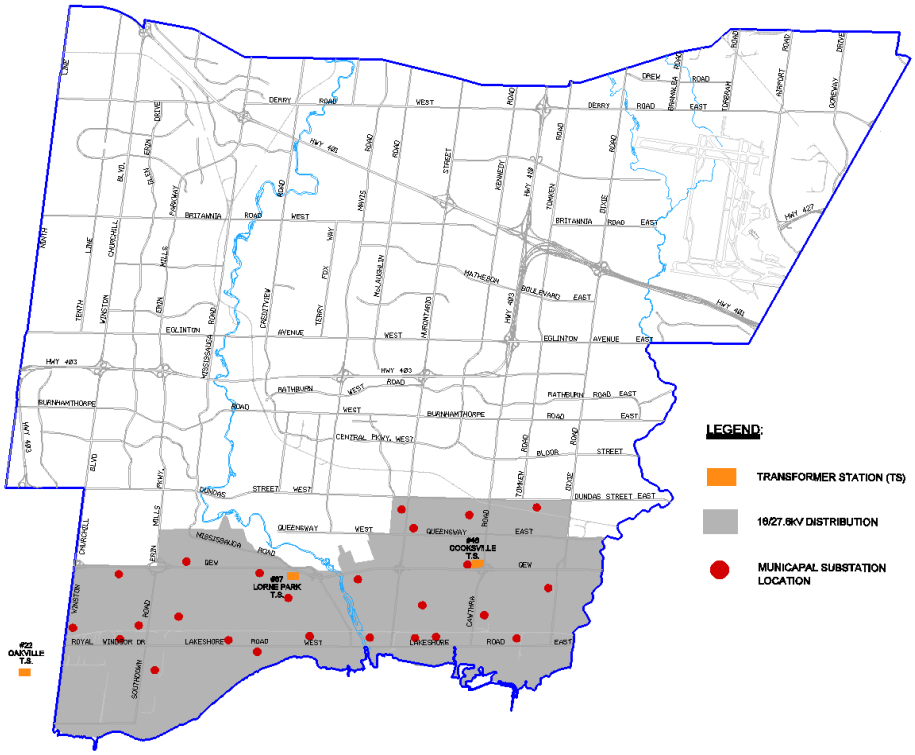


Figure 4.4 – Map of Enersource South 16/27.6 and 2.4/4.16kV Distribution Systems

4.1.2.3 West 8/13.8kV Distribution System

The West 8/13.8kV Distribution System covers the same geographical area as the 44kV subtransmission system, as shown in Figure 4.1. However, due to the large area and number of customers, the 8/13.8kV distribution system has been divided into west and east distribution systems, which is consistent with the division between the west and east 44kV subtransmission systems. All customers on this West 8/13.8kV system are connected directly to the distribution feeders supplied by Enersource MS's.

This area contains 22 MS sites comprised of 36 step-down transformers rated 44/13.8kV. This distribution system utilizes 129 distribution feeders.

The area serviced by this system is illustrated in Figure 4.5 below:

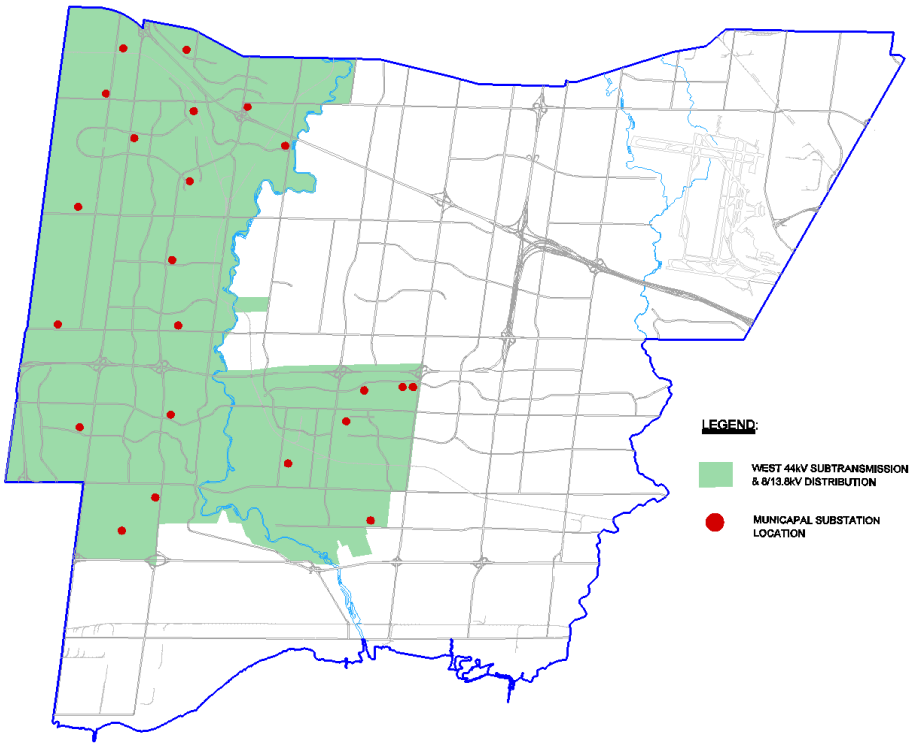


Figure 4.5 – Map of Enersource West 8/13.8kV Distribution System

4.1.2.4 East 8/13.8kV Distribution System

All customers on this system are connected directly to the distribution feeders supplied by Enersource MS's.

This area contains 17 MS sites comprised of 27 step-down transformers rated 44/13.8kV. This distribution system utilizes 86 distribution feeders.

The area serviced by this system is illustrated in Figure 4.6 below:

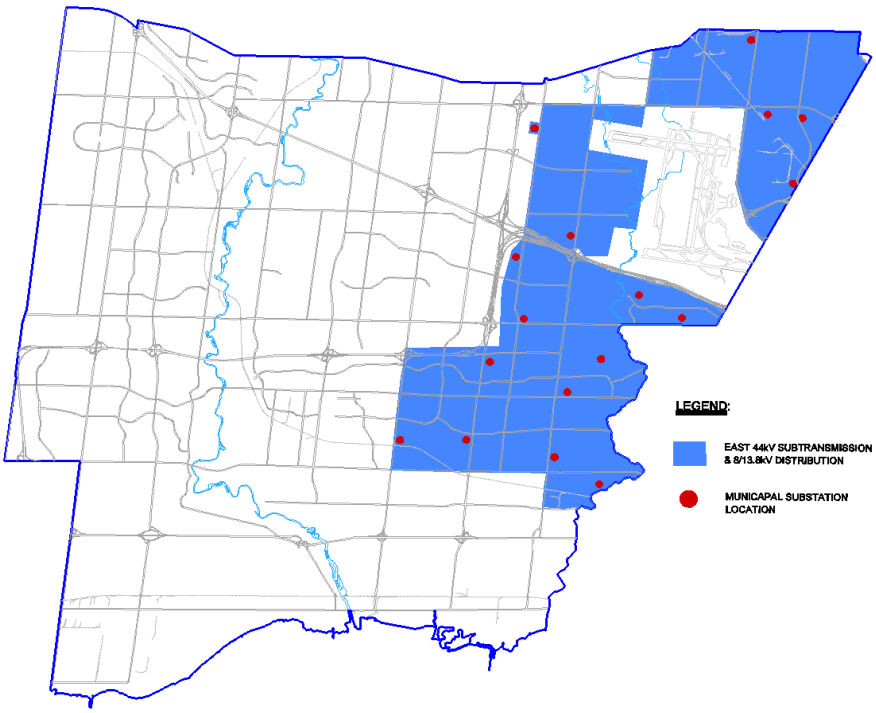


Figure 4.6 – Map of Enersource East 8/13.8kV Distribution System

5. Historical System Demand

Ontario's electricity demand is influenced by weather, calendar, economic activity and demographic drivers. Economic activity includes elements such as employment, industrial output, manufacturing and development. Peak system demands are short term durations in which Enersource's distribution system is stressed and depended upon by a large number of loads. Peak demand periods are heavily influenced by extreme weather conditions in addition to the economic and demographic elements described.

With the reduction of electrical heating and increasing demand for cooling, Enersource has shifted from a winter peaking to a summer peaking system. Since the demand on the system is at its peak in the hot summer months, the summer period heavily constrains the operation of Enersource's distribution system. In July, 2011, Enersource's system demand peak was 1,609 MW which was slightly below the all-time peak demand of 1,610 MW registered on August 1, 2006, which also coincided with Ontario's all-time peak.

Figure 5.1 below graphically illustrates Enersource's system peak demand from 1996-2011.

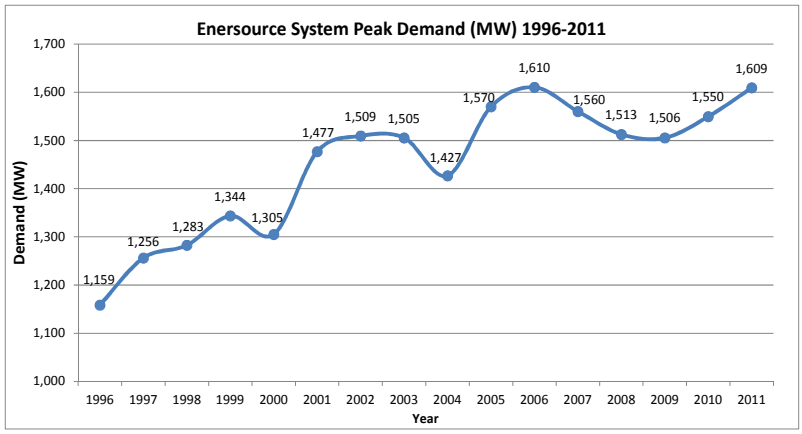


Figure 5.1 –Enersource System Peak Demand (1996-2011)

A decrease in system peak demand from 2007 to 2010 is attributed to reduced economic activity resulting from the 2008 recession, which especially impacted the commercial and large industrial customers in Mississauga and was compounded by mild summer weather. Another attribute to the decreased peak demand experienced includes energy efficiency driven by conservation and demand side management ("CDM") programs delivered by Enersource.

HISTORICAL RELIABILITY

6. Reliability History

System reliability is a key performance measure and is an OEB requirement for every electricity distributor to maintain reliability performance within its own three year range. In order to meet this requirement, Enersource has implemented several system reliability programs.

Enersource uses industry standards to measure and benchmark System Reliability Performance. The System Reliability Performance definitions are set by the Service Continuity Committee (SCC), which are a subgroup to the Canadian Electricity Association (CEA). Enersource follows the guidelines set out by CEA's Electric Power System Reliability Assessment program (EPSRA) which governs system continuity statistics for the entire electrical industry. Enersource implemented an Outage Management System (OMS) in 2009 which enhanced the ability to track reliability statistics.

The key measures of reliability are System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). Frequency relates to the system performance whereas duration relates to the outage time.

For 2011, Enersource experienced 1.97 interruptions and 53.3 minutes of interruptions per customer. For 2010 these measures were 1.32 and 35.0 and for 2009 these measures were 1.18 and 36.7 respectively. The time period from 2010 to 2011, Enersource experienced an increase in outage minutes from 6,673,600 minutes to 10,277,717 minutes of total outages. These reliability measures are included in Table 6.1.

The main contributors toward the negative reliability trend include Loss of Supply, several severe weather storms as well as a high number of equipment failures.

Additional information and details regarding reliability results, incident cause classification and equipment statistics of outages from 2007 up to 2011 are listed in Tables 6.1, 6.2, 6.3 and Charts 6.1 and 6.2.

Reliability Statistics					
	2007	2008	2009	2010	2011
INTERRUPTIONS	377	384	852	2,083	1,027
CUSTOMERS AFFECTED	142,035	135,413	221,578	251,366	380,772
CUSTOMER MINUTES	7,075,965	3,626,325	6,893,927	6,673,600	10,277,717
SAIDI (Minutes)	38.7	19.6	36.7	35.0	53.3
SAIFI	0.78	0.73	1.18	1.32	1.97
SAIFI (MI)	4.0	3.9	5.3	3.2	5.0
CAIDI (Minutes)	49.8	26.8	31.1	26.5	27.0

Table 6.1 –Enersource Reliability Statistics (2007 - 2011)

Cause Codes Statistics (Customer Minutes)					
Cause Codes	2007	2008	2009	2010	2011
Unknown/Other	87,808	113,143	306,007	100,669	180,650
Foreign Interference	301,821	453,127	1,134,820	466,580	882,668
Scheduled	58,203	172,424	547,965	1,939,026	682,740
Loss of Supply (Hydro One)	371,944	513,037	402,209	362,222	1,893,664
Tree Contacts	209,448	166,761	469,506	257,916	893,379
Lightning	43,686	35,958	201,274	62,454	38,475
Defective Equipment	2,914,798	2,046,500	2,794,332	3,051,586	5,219,938
Weather	3,046,285	101,115	971,640	422,209	49,927
Adverse Environment	40,746	4,376	4	0	19,492
Human Element	1,226	19,884	66,170	10,938	416,784
Grand Total	7,075,965	3,626,325	6,893,927	6,673,600	10,277,717

Table 6.2 –Enersource Cause Code Reliability Statistics (2007 – 2011)

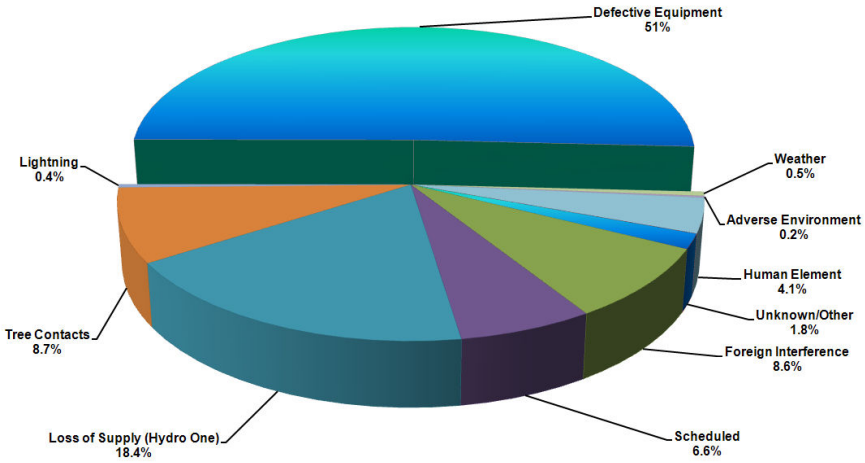


Chart 6.1 – Chart of Enersource Customer Minutes by Cause (2011)

Equipment Statistics (Customer Minutes)					
Cause Codes	2007	2008	2009	2010	2011
Underground Cable	1,808,340	1,023,062	1,917,155	2,120,732	3,143,850
Fuse	15,635	1,867	54,615	39,211	38,392
Insulators	27,293	240,811	70,412	2,687	42,884
Loadcenters	84,328	63,446	25,374	68,884	421,281
Overhead Equipment	150,379	341,622	215,713	230,471	1,098,335
Others/Unknown	0	5,320	122,939	62,183	133,394
Splices	650,821	38,780	239,933	277,098	0
Switches	28,732	79,333	32,581	24,938	86,549
Elbows/Terminations	35,500	130,912	26,505	55,984	62,340
Transformers	113,770	121,347	89,105	169,398	192,913
Total CM due to Equipment	2,914,798	2,046,500	2,794,332	3,051,586	5,219,938

Table 6.3 –Enersource Equipment Failure Statistics (2007 - 2011)

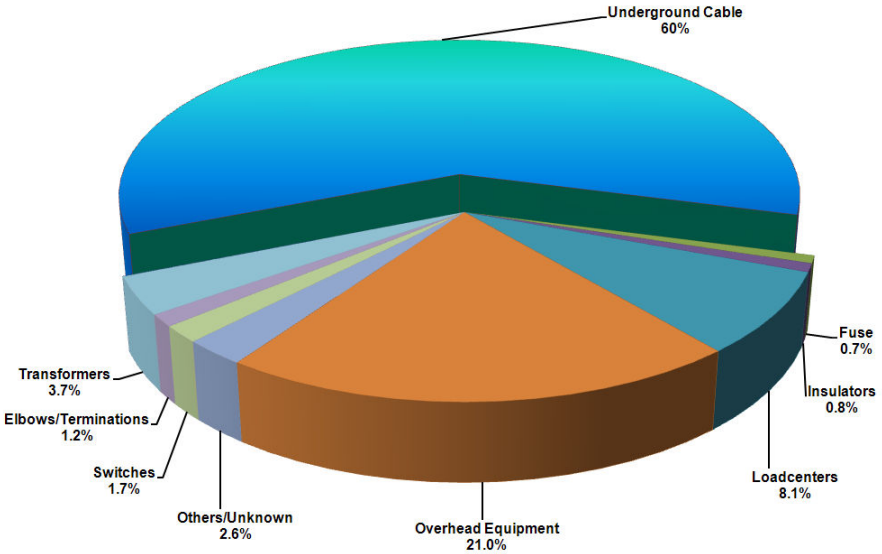


Chart 6.2 – Chart of Enersource Equipment Failure for 2011

AMP OVERVIEW

7. Overview

The objective of the Enersource's AMP is to outline the asset management practices which are part of an optimized lifecycle strategy for Enersource's electricity system assets. The scope of the AMP encompasses major projects and programs that are needed to sustain Enersource's electrical system.

The objectives of the AMP are to:

1) report on the performance of the power system and
2) identify risks and challenges that would adversely affect the ability to deliver economical and reliable power to Mississauga

Fundamental requirements of effective development and management of a power system is prudent planning, strategy, mission and values. The AMP provides planning direction for power system development, sustainment, reliability, asset inspections, maintenance and replacement programs, as well as increases to the overall system capacity.

The AMP details how Enersource manages, maintains and reinforces the electrical distribution system in a cost effective manner. In addition, it reviews the capital, operating and reliability trends over the past five years. The AMP covers a period of five years beginning January 1, 2012. Beyond 2012, general forecasts are provided which will be reviewed annually as part of the AMP yearly update.

Managing aging infrastructure and system capacity requirements will continue to present challenges. Enersource's power system assets range in age from new to over 50 years' old. The management of these assets is critical to providing the safe, reliable and efficient electricity distribution services to its customers.

Continued focus will be on managing the aging infrastructure, particularly in the management of poles, underground cables, distribution transformers, substation transformers and substation switchgear. Given the large expansion of the system in the 1980's and 1990's, a considerable amount of replacement is expected before the next twenty years. This must be prudently managed, to achieve the lowest long-term owning cost of the power equipment while conforming to standards, requirements, and meeting the needs and expectations of Enersource's customers in terms of performance and reliability.

AMP INVESTMENT STRATEGY AND INITIATIVES

8. Asset Management Strategy

The objective of the AMP is to evaluate physical assets associated with power delivery, and to make recommendations for the replacement and maintenance of the assets in order to achieve the lowest long term owning cost. The goal of Enersource's AMP is to effectively manage its assets on a life-cycle basis, with spending policies that align with corporate strategy and performance objectives.

Enersource uses several sources of data such as asset condition, criticality, reliability information, as well as, environmental and customer impacts. The data is computed and tools are used to produce a priority list of projects by asset classes. Several other requirements and risks are considered as shown in Sections 8.1 and 8.2.

Once each class of asset is evaluated, a list of projects is created. Each investment is described by a driver and scope of the project. A driver could be safety, reliability improvement, load growth, new customers or others. The main focus is on the next five years; however, long term outlook is also produced using the available information.

Finally, the overall list of projects is evaluated against corporate objectives, and each project is examined according to its cost and benefit analysis.

The objective of this process is to select the projects that deliver and support the required functions at the desired level of performance, that are sustainable for the foreseeable future, and that also stay within the targeted levels of risk and budget

8.1 Requirements Based Identification

The asset management planning process is built around the management strategy with regards to these key factors: planning, prioritization, and execution of capital and sustainment projects. The projects and programs are identified based on the following requirement categories:

Capacity Requirements - maintain and expand the power system in an efficient way to fully utilize all assets and supply power to all customers

Service Quality Requirements - maintain the performance of the power system with regard to reliability, power quality, staying within defined targets, and supporting customer value

Customer Requirements - meet all compliance standards, including new service connections, responding to customers enquiries, and scheduling appointments within a specified timeframe

Strategic Initiatives - pursue and increase the effectiveness of the operations, maintenance programs, and development of the power system while minimizing the environmental impacts in support of good corporate citizenship

8.2 Risk Based Evaluation

Risks need to be controlled and mitigated to support Enersource's corporate governance needs and the due diligence responsibilities of management. The main focus of risk assessment is to identify and prioritise risks associated with managing and expanding the power system assets. The objective would be to avoid catastrophe, reduce uncertainty, and improve predictability.

At Enersource, the risks associated with the AMP are composed of six main categories:

Economic Risks - is the condition of the existing assets evaluated to ensure they are repaired or replaced effectively to achieve the lowest long term owning costs? Do the new projects bring a maximum return on capital while delivering reliable power to customers?

Service Quality Risks - what is the impact of asset failure to customers? Are critical assets maintained properly and replaced prior to their expected end of useful life?

Regulatory/Legal Risks - does Enersource remain fully compliant in all legal and regulatory aspects of its operations?

Environmental Risks - are all assets and work procedures compliant with the current environmental standards and laws?

Reputational Risks - what could cause Enersource's status to deteriorate from a highly respected utility known for an efficient and effective operation while delivering quality performance and product at fair cost?

Employee/Public Safety - is the entire Enersource power system built, designed, and maintained with safety in mind, for both Enersource employees and the community?

As a part of the planning process, risk evaluations are completed for each asset class. The risk evaluations involve identifying the risk significance of each asset and how would it affect the six main risk categories, as well as evaluating the consequences of not proceeding with the capital or sustainment investment.

The process to evaluate assets was completed through an internal multi-disciplinary working group consisting of expert representatives from internal divisions and was lead by Internal Audit & Enterprise Risk group. Using risk evaluation software application which permits voting on each risk attribute for each asset class in an anonymous manner to ensure influence was not a factor in the risk assessment. Once the group completed voting for each asset class, the risks factors were compiled and were used to rank the asset classes from highest risk profile to lowest.

8.3 Asset Management Matrix

As a final step of the investment evaluation, all requirements and risks are considered as shown in Figure 8.3 below. Risk levels are on a scale of 1 to 5 with the higher numbers reflecting the highest risk.

	Risk						
Asset Class	**Economic**	**Service Quality**	**Regulatory/ Legal Compliance**	**Environmental**	**Reputational**	**Employee/ Public Safety**	**Average Risk Level**
Substation Power Transformers	3.8	4.5	2.5	4.0	3.7	3.0	3.6
Rolling Stock/Fleet	3.5	3.0	3.3	2.8	4.0	3.3	3.3
IT Systems	4.2	3.8	4.0	1.5	3.3	1.5	3.1
Wholesale and Smart Meters	3.3	2.5	4.8	1.7	3.8	1.8	3.0
Engineering Assets/IOM/Mapping	3.5	3.7	2.7	1.5	3.0	2.8	2.9
Green Energy Act	2.2	1.8	4.2	2.2	3.5	3.2	2.9
Land Acquisition/Building Renovation	4.2	2.8	2.2	1.3	3.7	2.8	2.8
Grounds and Buildings	3.8	2.8	1.7	3.0	2.3	2.5	2.7
Substation Circuit Breakers	3.5	3.7	2.3	2.3	1.8	2.2	2.6
Road Projects	3.0	1.7	4.2	1.5	2.8	1.7	2.5
Underground Cables - primary	3.5	3.5	1.7	1.8	2.3	1.8	2.4
Vault Transformers	2.7	3.0	1.7	2.5	3.0	1.5	2.4
Pad Mounted Transformers	2.5	2.2	1.3	2.5	2.5	2.2	2.2
Wood Poles	2.0	2.3	2.8	1.5	2.0	1.8	2.1
Pad Mounted Switchgear	3.0	2.3	1.5	1.3	1.8	2.0	2.0
Underground Cables - local	1.3	2.0	1.2	1.3	2.7	2.7	1.9
Switches	2.5	2.7	1.5	1.2	1.2	1.8	1.8
Pole Mounted Transformers	1.5	2.0	1.5	2.0	1.3	2.0	1.7
Concrete Poles	1.8	1.5	1.2	1.2	2.2	1.7	1.6

Table 8.3: Asset Investments and Risk Factors

AMP INPUT DATA SOURCES

9. Analytical Data Sources

- Asset Condition Assessment
- Load Forecast – System Capacity
- Testing and Inspection Program
- Integrated Operating Model
- Automated Mapping / Facilities Management / Geographical Information System

9.1 Asset Condition Assessment

Conducting an Asset Condition Assessment (an "ACA") is a process whereby the condition of all key asset categories owned by Enersource is assessed. The 2011 undertaking of an ACA resulted in the development of a health index (the "Health Index") for each asset class. The ACA determined the Health Index distribution for the entire population of assets in each class, and develop a forty-year condition-based replacement plan. The report that resulted from the ACA is used as one of the inputs for the AMP which evaluates the existing programs (sustainment, expansion and regulatory) and develop new ones in order to address the required replacement rates for all asset groups considered in the ACA.

9.2 Load Forecast – System Capacity

The long term system load forecast is utilized to identify the projected peak load demands in Mississauga. System capacity load forecasting is long term peak demand projection developed for each of the four areas of power system outlined in section 4 of this report. Load forecasting methodology utilized is similar to the short term peak demand forecasting methodology applied to revenue forecasting. Multivariate regression models are developed for each of the four areas using Itron MetrixND statistical application. Model inputs include sixteen years of actual energy purchases (1996-2011) from the Independent Electricity System Operator (IESO), actual weather data from Environment Canada weather station at the Lester B. Pearson International Airport, calendar data and demographic outlooks provided by the City of Mississuaga`s Building and Planning department including employment and population for each area.

Since forecasting weather over a long term with confidence is not possible, the load forecasting methodology does not predict weather but rather utilizes an extreme weather scenario to project system capacity requirements under extreme weather conditions. This process is similar to that adapted by the IESO in developing the assessment of the reliability and operability of the Ontario electricity system. Although extreme weather is inappropriate to use as the scenario for energy consumption as the likelihood of observing sustained extreme weather, the use of extreme weather scenario based on historical 31 years of actual weather is appropriate in projecting short term peak demand system capacity.

The city has gone through a very aggressive expansion period spanning the mid 1980's to the mid 2000's. Currently Enersource's expansion has slowed relative to the past peak periods, and available green space for further development has been significantly reduced.

9.3 Testing and Inspection Program

Enersource has several inspection programs for various distribution and subtransmission equipment. The inspection programs include monthly substation inspections, switchgear inspections and a yearly infrared overhead system inspection program. In addition, Enersource performs several tasks where informal inspections are performed. For example, during switching, responding to customer calls, insulator washing, fire prevention vault inspections or switchgear dry ice cleaning, the crews report on the condition of the equipment.
From the above inspection programs, the information pertaining to the condition of the equipment is recorded and considered for spot equipment replacements and rebuild projects.

9.4 Integrated Operating Model

The Integrated Operating Model (the "IOM") is a computer-based system that provides a single user interface for monitoring the grid, allowing for faster, more informed decision-making. The IOM consolidates information on location and attributes of distribution equipment, real-time crew location, and active outages including the number of customers affected. The IOM also performs the requirements of an Outage Management System (an "OMS"), which uses outage probability modeling to assist the Control Room Operators in determining the most likely source of an outage and allowing them to prioritize restoration efforts.

At Enersource, the type, duration, and cause of each outage is recorded by the Control Room Operators in the IOM and this information is the source of the reliability statistics. If equipment fails in the field, a follow-up report is created in the IOM, which is used for tracking and prioritizing follow-up activities.

In addition to being used as the basis for reliability statistics, the outage information stored in the IOM is used to investigate the worst-performing feeders and to identify low reliability areas.

9.5 Automated Mapping /Facilities Management/Geographical Information System

The Automated Mapping/Facilities Management/Geographical Information System (the "AM/FM/GIS") captures both graphical and database information pertaining to Enersource's field equipment. The AM/FM/GIS consists of a map of Mississauga including all streets and lots, with the location of Enersource equipment and civil structures overlaid on the map in the appropriate locations. For each item, several characteristics or attributes, including connectivity information, is captured in the database. Since the deployment of the AM/FM/GIS, the number of attributes maintained for each equipment item has grown to accommodate a diverse set of user requirements, and the system is one of the primary sources of asset information for Enersource. The equipment attributes along with equipment counts are used as data inputs to the ACA. In addition, in the future, the AM/FM/GIS system will record all maintenance activities.

INPUT DATA FINDINGS

10. Asset Management Data Findings

10.1 Asset Condition Assessment Report

To assist with the development of the AMP, Enersource performed a condition assessment of existing assets in order to assist in prioritizing and allocating sustainment resources. Enersource commissioned an independent third party to perform an ACA of Enersource's assets.

In early 2011, Enersource selected and engaged Kinectrics Inc. to complete the ACA. Kinectrics has a wide range of experience in assessing the condition of utility assets. Enersource utilized the Kinectrics' ACA in developing the 2012 AMP.

The ACA focused on the following asset classes:

Check list:

- municipal substation power transformers;
- substation circuit breakers
- pole mounted transformers
- single phase pad mounted transformers
- three phase pad mounted transformers
- vault transformers
- pad mounted switchgears
- switches
- underground cables
- wood poles and
- concrete poles

Data used in the study was obtained from Enersource's AM/FM/GIS and included the following asset information:

- age
- size
- voltage
- type
- sustainment records
- inspection records and
- testing evaluations

Based on Kinectrics' formulations and industry-accepted methodologies, equipment replacement rates for all of the above asset classes were developed.

10.2 ACA Asset Class Findings

10.2.1 Municipal Substation Transformer

As an asset class, substation power transformers constitute one of the largest investments in a utility's system. They are installed in municipal substations. The design life of a substation power transformer is approximately 40 years and with proper maintenance the life can be achieved.

The substation power transformers are used to step down the voltages from 44 kV to 13.8 kV or 27.6 kV and from 27.6 kV to 4.16 kV. The transformer sizes are 3 MVA, 5 MVA, 10 MVA and 20 MVA. Special consideration is given to these assets since a transformer failure may affect up to 5,000 customers.

It is Enersource's practice to collect oil samples at least once per year from every power transformer and to test them in order to determine the level of dissolved gases and the oil quality. Dissolved Gas Analysis is the most sensitive and reliable technique used for evaluating the health of oil-filled electrical equipment.

There are also monthly substation inspections and preventive maintenance programs in order to detect incipient weaknesses or impending failures.

The monthly inspections consist of visual inspections of the units in order to ensure that the transformer fans are working properly, as well as to check the oil level and ensure temperature gauges are indicating correctly. The transformers are checked for leaks as well.

The preventive maintenance program is based on elapsed time (usually every five years) and the main activities are:

- testing of all controls (relays gauges)
- in-depth inspection of the cooling system
- transformer bushing inspections
- insulation power factor testing and
- transformer turn ratio testing

At the end of 2010 there were 102 transformers installed in Enersource municipal substations. The average age of the population is 22 years. The demographic breakdown of the power transformers is shown in Figure 10.2.1.1.

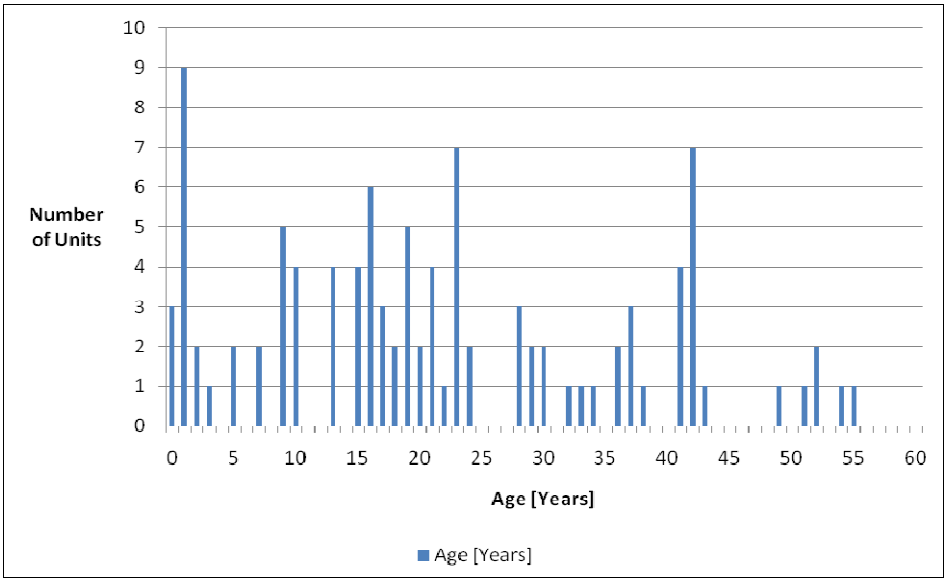


Figure 10.2.1.1: Substation Power Transformers - Age Distribution

According to the ACA, the present condition of Enersource's power transformers is as follows:

- 25 units in fair condition;
- 38 units in good condition; and
- 39 units in very good condition.

The suggested replacement rate (Figure 10.2.1.2) is seven transformers over the next ten years with an increasing number (averaging approximately three transformers per year) for the following10 years. The ACA assumes that 20% of the power transformer population will fail by 40 years and 99% of the population will fail by 60 years.

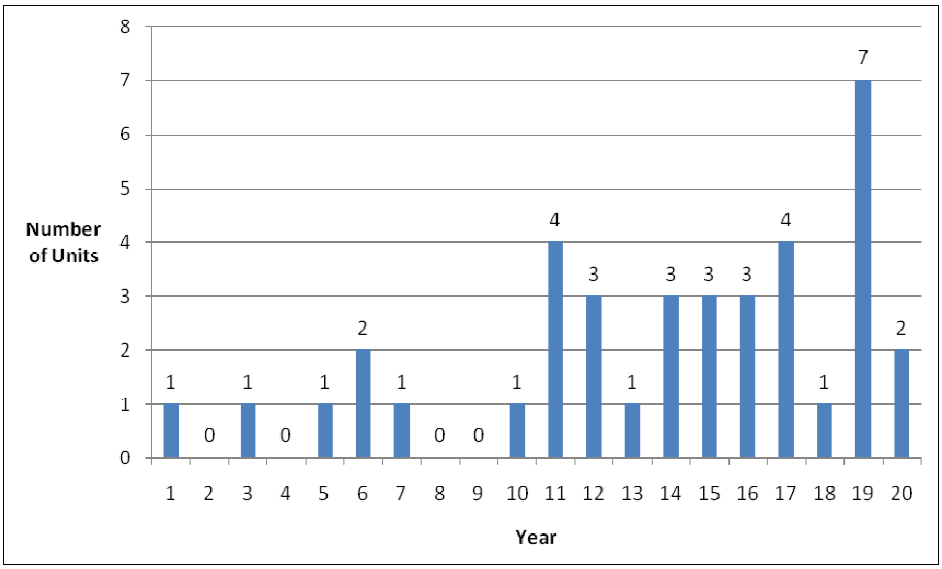


Figure 10.2.1.2: Substation Transformers - Recommended Replacement Rates

Enersource replacement program strategy considers replacing a unit based on the health index, location / number of customers served, transformer protection enhancement (implementation of the transformer differential protection) and also takes into account the other substation assets including the building and grounds.

There are situations when, in order to promote standardization and to better serve Enersource customers, the substation layout configuration is modified and the transformers needed to be replaced not because they approached the end of life but because they do not fit in the new configuration. The replaced transformers become spare inventory units or are used to replace other units that were in worse conditions and prone to failure.

In order to maintain a healthy power transformer fleet, we plan to continue to replace the power transformers on the same pace as in the most recent previous years.

10.2.2 Substation Circuit Breakers

The basic function of circuit breakers is to detect a fault condition and, by interrupting continuity, to immediately discontinue electrical flow. They are housed in metal clad switchgear cubicles with the associated controls. The circuit breaker voltage ratings are 4.16 kV, 13.8 kV, 27.6 kV and 44 kV. They can be classified by the medium used to extinguish the arc:

- vacuum circuit breakers
- air circuit breakers; and
- SF6 circuit breakers

In accordance with accepted engineering and utility practice Enersource has maintenance programs in place for the circuit breakers and switchgear units. Every switchgear unit is visually inspected monthly and every five years the substation is isolated and the circuit breakers maintained and tested together with the associated controls.

At the end of 2010 there were 464 circuit breakers installed in Enersource's municipal substations. The average age of the population is 22 years old. The demographic breakdown of the population is shown in Figure 10.2.2.1.

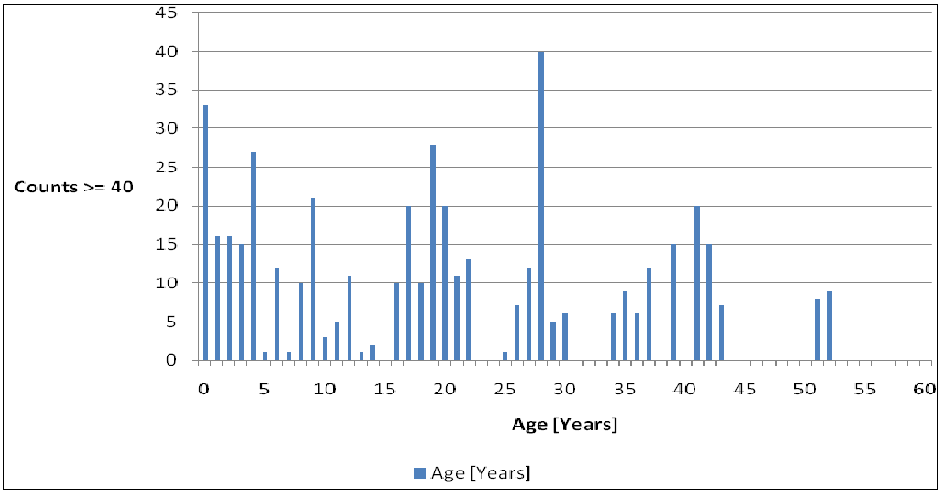


Figure 10.2.2.1: Circuit Breakers - Age Distribution

The ACA assumes that 20% of the population of circuit breakers will fail by 40 years and 99% of the population will fail by 60 years.

According to ACA the condition of the circuit breakers is as follows:

- 55 units (12% of the population) – very poor
- 40 units (9% of the population) – poor
- 60 units (13% of the population) – fair
- 96 units (21% of the population) – good and
- 213 units (46% of the population) – very good

The ACA suggested replacement chart is shown in Figure 10.2.2.2.

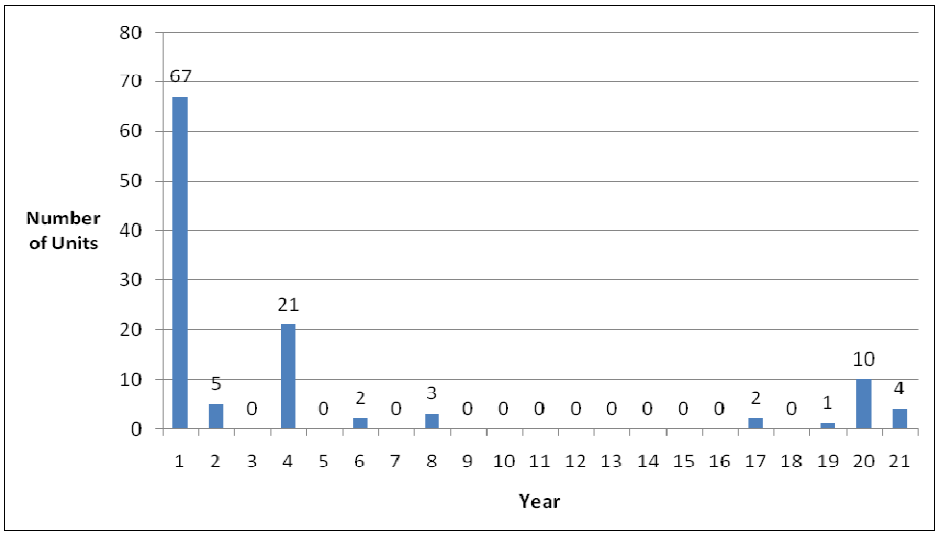


Figure 10.2.2.2: Circuit Breakers - Recommended Replacement Rates

Based on Enersource's operating experience and the findings during switchgear maintenance, certain circuit breakers have been found to be prone to failure and also pose a safety risk to substation technicians.

A replacement program has been implemented over the last four years to replace not only the breakers but the entire English Electric and PCG switchgear units due to their deficiencies.

All English Electric and PCG switchgear units will be replaced by the end of 2014 with new arc resistant units equipped with modern vacuum breakers using magnetic actuator technology.

Approximately 15 circuit breakers have been replaced each year over the past four years as part of the substations upgrade projects and Enersource plans to continue at the same replacement pace in the future. It is estimated that in the next three to four years all circuit breakers that are in very poor condition will be replaced.

Enersource has a program to replace the magnetic air circuit breakers with vacuum circuit breakers over the next 10 to 15 years. Also, Enersource is conducting an evaluation regarding the feasibility of replacing individual circuit breakers compared against the switchgear assembly.

The maintenance program and a pro-active approach regarding circuit breaker replacement are essential in avoiding major power disruptions due to substation equipment failure.

10.2.3 Pole Mounted Transformers

Distribution pole mounted transformers convert power from primary distribution voltages to 120/240V, 120/208V, 347/600V, or 600V secondary voltages. In the past, pole mounted transformers were installed in various sizes; however, to minimize inventory the sizes were standardized to 25kVA, 50kVA, 100kVA and 167kVA. Pole mounted transformers are smaller and supply up to 25 customers, and if they fail, the environmental, reliability, and customer impact is minimal. Utility practice is to run pole mounted transformers to failure. If the entire area is scheduled for a rebuild, then the transformers are replaced along with the poles, conductors, insulators and other pole line hardware.

At the end of 2010, there were 5,248 pole mounted transformers installed at Enersource. The average age of the population is 21 years. The ACA assumes that 20% of the population will fail by 45 years and 99% of the population will fail by 60 years. Five percent of the pole mounted transformer population is 45 years or older.

The rate of installation of pole mounted transformers has varied widely over the past 60 years. The installation rate was fairly low up to the early 1980's, after which point the city started to develop faster in the 1980's and 1990's. The installation rate more than doubled during the mid-1980's, and gradually started to stabilize. Finally, in 2009 and 2010, the rate of installation increased again due to the PCB transformer replacement program. Now, since many of the PCB transformers have been replaced, the rate is expected to stabilize. The demographic breakdown of pole mounted transformers is shown in Figure 10.2.3.1.

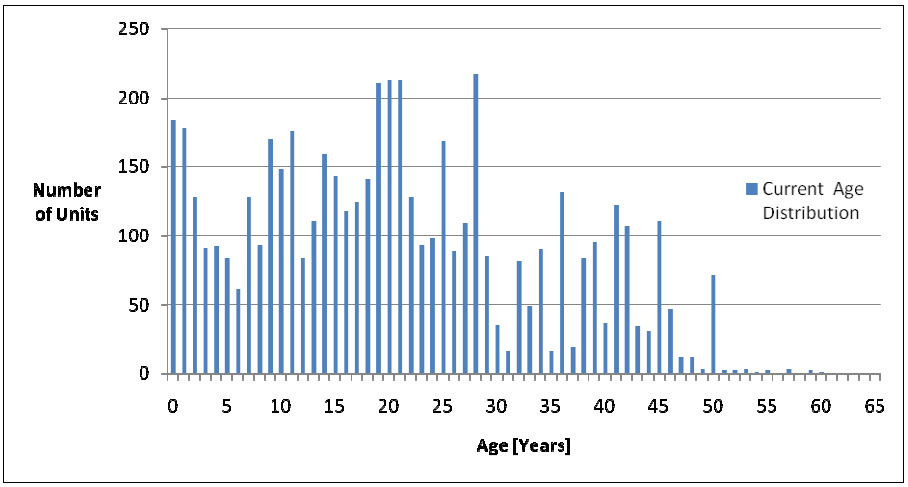


Figure 10.2.3.1: Pole Mounted Transformers - Age Distribution

According to the ACA, over 95% of the pole mounted transformers are in good or very good condition. Since several hundreds of transformers are near the end of their expected life, the ACA suggests that Enersource start replacing between 77 and 123 transformers each year.

According to the suggested replacement rates, after 40 years, 4,184 transformers will be replaced. In contrast to the historical rate of installation, on average, each year for the next 40 years Enersource should be replacing 105 transformers. The replacement quantities are shown in Figure 10.2.3.2.

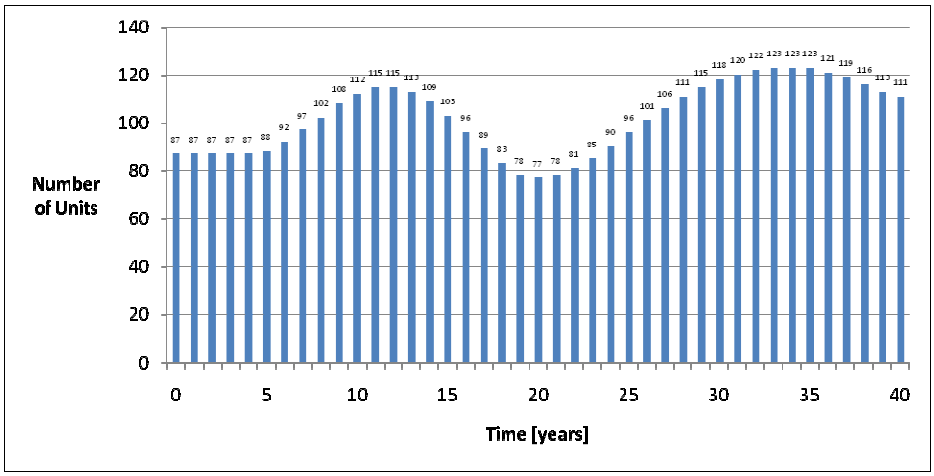


Figure 10.2.3.2: Pole Mounted Transformers - Recommended Replacement Rates

In 2010, through overhead rebuilds, failures and spot replacements, Enersource replaced approximately 130 pole mounted transformers. In 2011, approximately 100 transformers were replaced. The budget and labour resources will allow for replacement of a similar number of pole mounted transformers in 2012.

The current replacement rate for the pole mounted transformers is in line with the recommended replacement rate. The rate will be monitored in the future and further studies of transformer failures will be examined to ensure that the rate of replacement is appropriate.

10.2.4 Single Phase Pad Mounted Transformers

Single phase pad mounted transformers are used in the underground residential distribution system to step down the primary distribution voltages to a 120/240V secondary voltage. The secondary winding is usually divided into two equal parts each part is having a voltage of 120V between terminals. Two parts are connected in parallel for 120V and in series for 240V. Single phase pad mounted transformers are typically used to supply power to residential customers in subdivisions. They are typically installed on a concrete foundation on the city owned boulevard in front of houses.

In the past, several different sizes of single phase pad mounted transformers were installed in the city. In 1992, the residential sizes were standardized to 100kVA. This was done to reduce inventory levels. In addition, for special applications, such as traffic lights, cellular towers or bulk

metered customers; 25 and 167kVA single phase pad mounted transformers are also available. A typical single phase pad mounted residential transformer has a provision for up to 14 secondary service connections.

At the end of 2010, there were 14,141 single phase pad mounted transformers in service. The average age of the population is 20 years. The ACA study assumes that 20% of the population will fail by 35 years and 99% of the population will fail by 45 years. Approximately nine percent of the population is 35 years or older.

The rate of installation of pad mounted transformers has varied widely over the past 50 years. The installation rate was fairly constant up to the early 1980's. However, when the city started to intensify development in the mid 1980's and 1990's, the installation rate increased. The installation rate more than doubled during the mid 1980's and has now gradually started to stabilize. In the mid 1990's the number of the transformers installed appears to decline slightly. This decline in the population demographics is likely caused by replacement of several hundreds of faulty transformers that were purchased in mid 1990's. Some of the transformers purchased at that time would fail prematurely within a first few years from the installation. In the late 2000's, the population demographics increased again due to the PCB transformer replacement program. Now, since many of the PCB transformers have been replaced, the rate of installation is expected to be driven predominately by future growth and underground rebuilds. The demographic breakdown of pad mounted transformers is shown in Figure 10.2.4.1.

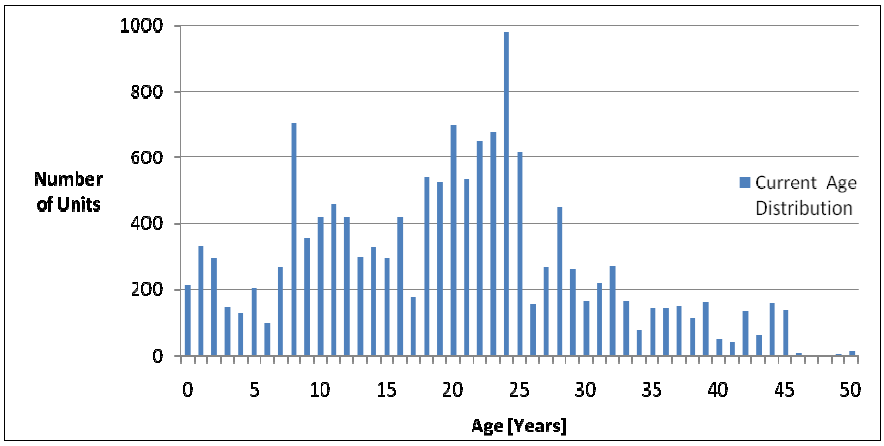


Figure 10.2.4.1: Single Phase Pad Mounted Transformer Age Distribution

According to the ACA, over 90% of the single phase pad mounted transformers are in good or very good condition. However, since several thousand of the transformers are near the end of their expected life, the ACA suggests an initial replacement of 751 transformers. This initial surge in the replacement rate is caused by a backlog of transformers that are overdue for replacement. After the first year, the ACA suggests replacing approximately 400 transformers per year and then, because of the spike in the population distribution, increase the rate to over 730 transformers per year.

According to the suggested replacement rates, after 40 years, 14,931 transformers will be replaced. In contrast to the historical rate of installations, each year for the next 40 years Enersource should be replacing an average of 373 transformers per year. The replacement quantities are illustrated in Figure 10.2.4.2.

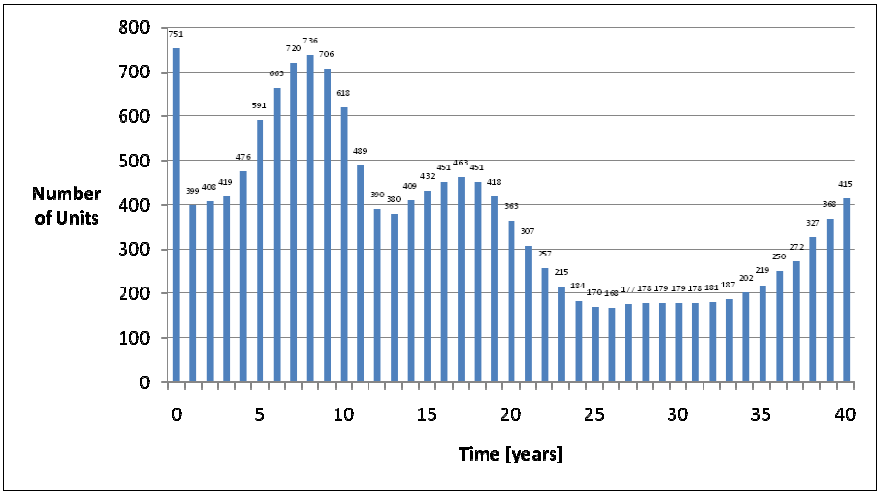


Figure 10.2.4.2: Single Phase Pad Mounted Transformers - Recommended Replacement Rate

In 2010, through underground rebuilds, failures, and spot replacements, Enersource replaced approximately 230 single phase pad mounted transformers. These numbers were slightly higher than the typical historical replacement rate due to the PCB transformer replacement program. In 2011, approximately 200 transformers were replaced. The 2012 budget and labour resources allow for replacement of a similar number of single pad mounted transformers.

It is evident that the current replacement rate of single phase pad mounted transformers is significantly lower than the rate suggested by the ACA. Current financial constraints, limited labour resources, and the low impact of failures by this equipment category, the suggested current rate is acceptable for a short term. However, in the long term, the replacement rate will have to be increased to match the rate suggested in the ACA in order to avoid aging assets past their expected life. Currently, reliability is not affected greatly by single phase pad mounted transformer failures, since over 90% of the population has a good or very good health index and only a moderate number of transformers fail each year. However, if Enersource does not increase the replacement rate, the population of single phase pad mounted transformers will start aging, resulting in an increase in number of transformer failures affecting reliability more significantly than today.

10.2.5 Three Phase Pad Mounted Transformers

Three phase pad mounted transformers are used in the underground distribution system to step down the primary distribution voltages to 120/208V, 347/600V, or 240/416V. Three phase pad mounted transformers are typically used to service industrial or commercial customers and

occasionally they supply apartment buildings. These transformers are typically installed on a concrete foundation on private property.

Three phase pad mounted transformers come in different sizes typically from 75 to 3000kVA. The most common sizes are 150kVA, 300kVA, 500kVA, 750kVA, and 1000kVA. The size of the transformer depends on the customer's service size and secondary voltage. In most industrial/commercial installations, only one customer is connected to a three phase transformer. However, in the case of individually metered condominium/apartment buildings, several hundred customers are connected to the same unit.

As of the end of 2010, there were 1,735 three phase pad mounted transformers in service. The average age of the population is 15 years. For the ACA study, the assumption was taken that 20% of the population will fail by 35 years and 99% of the population will fail by 45 years. Approximately seven percent of the three phase pad mounted transformer population is 35 years or older.

The rate of installation of the three phase pad mounted transformers has varied widely over the past 50 years. As in the case of the single phase pad mounted and overhead transformers, the installation rate for three phase pad mounted transformers was very low up to the mid 1980's. Prior to that time, the majority of the industrial/commercial and apartment building services were supplied by vault transformers. Most of the three phase pad mounted transformers were installed in the early 2000's and the rate of installation has stabilized since then. In 2009 and 2010, some additional transformers were replaced under the PCB transformer replacement program. The number of replacements was not as large as in the case of the overhead or single phase pad mounted transformers. The demographic breakdown of three phase pad mounted transformers is shown in Figure 10.2.5.1.

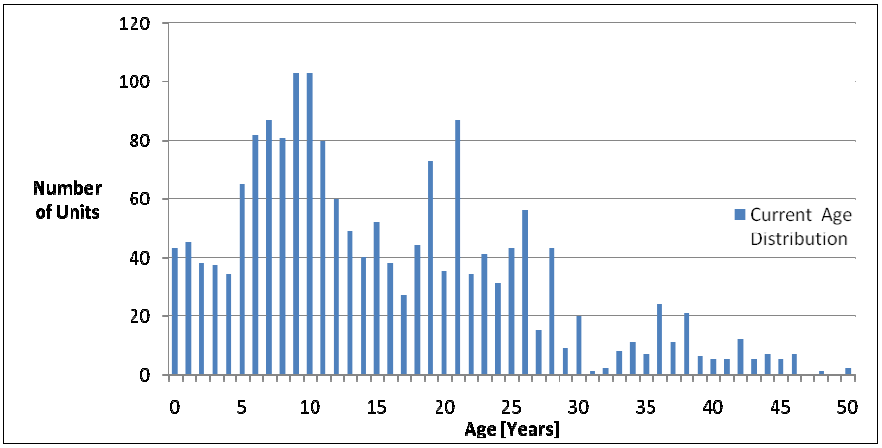


Figure 10.2.5.1: Three Phase Pad Mounted Transformer Age Distribution

According to the ACA, currently over 70% of the three phase pad mounted transformers are in good or very good condition. However, several hundred transformers presently have a poor or very poor health index. As a result, the ACA suggests an initial replacement of 42 transformers. As in the case of the single phase pad mounted transformers, this initial surge in the replacement rate is caused by

a backlog of transformers that are overdue for replacement. After the first year, the ACA suggests replacing from fourteen to nineteen transformers per year for the next eight years. After that the rate should gradually increase to 80 transformers per year to accommodate for the wave increase in the population distribution.

According to the suggested replacement rates, after 40 years, 1,708 transformers will be replaced. In contrast with the historical rate of installations, each year for the next 40 years Enersource should be replacing an average of 43 transformers. The replacement quantities are shown in Figure 10.2.5.2.

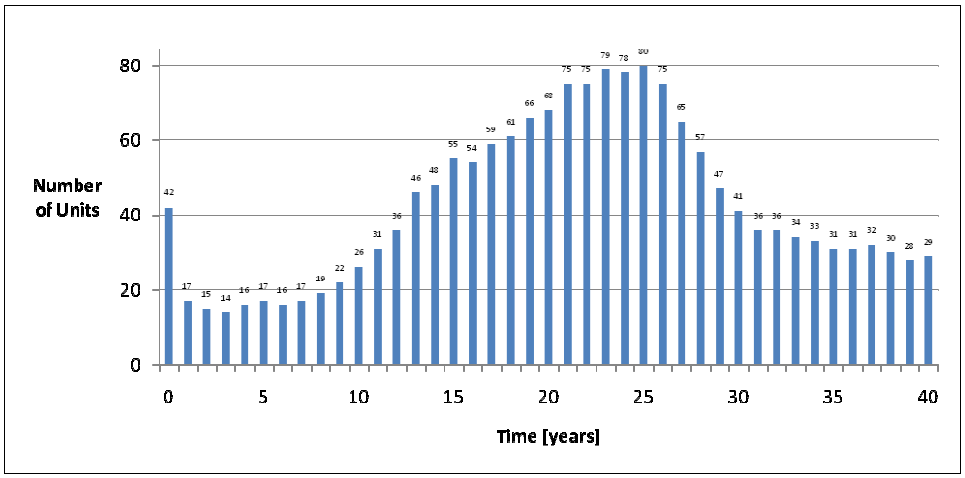


Figure 10.2.5.2: Three Phase Pad Mounted Transformers - Recommended Replacement Rates

In 2010 and 2011, through underground rebuilds, failures and spot replacements, Enersource replaced fewer than fifteen three phase pad mounted transformers annually. The 2012 budget and labour resources allow for the replacement of a similar number of pad mounted transformers.

It is evident that the current replacement rate of the three phase pad mounted transformer is significantly lower than the rate suggested by the ACA. Current financial constraints, limited labour resources, and the low impact of failures by this equipment category, the current rate is acceptable for the short term. Currently, Enersource has no dedicated programs that targets the replacement of the three phase pad mounted transformers. On average, ten transformers per year are replaced under cable replacement projects, and the transformers in the area that are past their expected useful life are replaced at the same time. Currently, Enersource's reliability and performance is not greatly impacted by three phase pad mounted transformer failures since typical installations supply only one customer, and the majority of the three phase pad mounted transformers population still has a good or very good health index. In the future, the plan is to increase main feeder and local distribution feeder cable rebuild projects, and replace aging three phase transformers under these projects.

10.2.6 Vault Transformers

Vault transformers are used in the underground distribution system to step down the primary distribution voltages to 120/208V, 347/600V, 240/416 or 600V secondary voltages. Vault transformers are predominantly used to supply power to industrial or commercial customers. Sometimes the transformers are also used to supply apartment buildings or townhouse complexes.

Vault transformer banks are made up of three single phase units that are interconnected with each other to supply three phase loads. As a comparison customers who are supplied from pole mounted transformers, are limited in terms of the size to 3-167kVA transformers, whereas vault transformation up to 3-750kVA is available. An additional benefit of the three single phase units is that if one of the units fails, the whole bank does not require to be replaced. The vault transformers are typically installed in a transformer vault room above grade. As a result, water drainage is not an issue as in the case of submersible transformer chambers.

In the past, several different sizes of the vault transformers were installed in the city. To reduce inventory levels, sizes of the vault transformers were standardized. Currently only 167 to 750kVA vault transformers are installed. In most industrial/commercial installations, only one customer is connected to a vault transformer bank, but in the case of individually metered townhouses or apartment buildings, hundreds of customers are connected to the same vault.

At the end of 2010, there were 3,885 vault transformers in service. The average age of the population is 26 years. The ACA assumes that 20% of the population will fail by 35 years and 99% of the population will fail by 45 years. According to ACA, approximately 21% of the vault transformer population is 35 years or older.

The rate of installation of the vault transformers has varied widely over the past 50 years. The rate of installation of the vault transformers was gradually increasing until the late 1980`s. At that time, due to issues with access, maintenance and the costly building space required for vault rooms, a design change was made from the installation of vault transformers to pad mounted transformers. Since then, each year only a small number of new vaults are built, in comparison with the number of three phase pad mounted transformer installations. The demographic breakdown of vault transformers is shown in Figure 10.2.6.1.

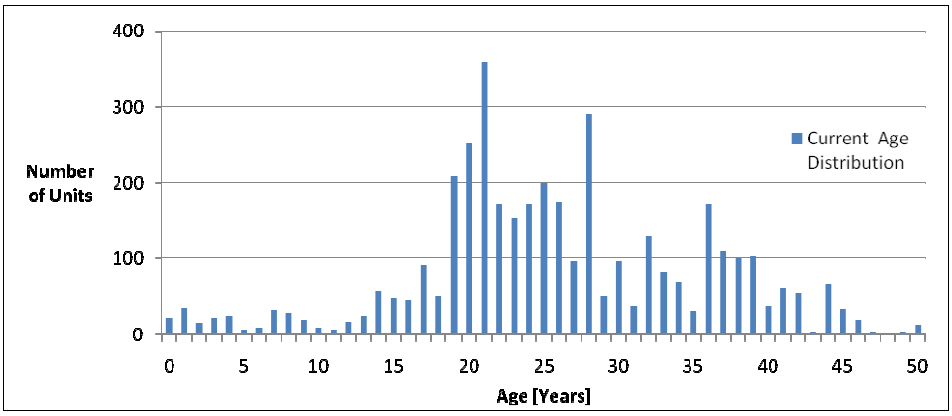


Figure 10.2.6.1: Vault Transformer Age Distribution

According to the ACA, although approximately 90% of the vault transformers are in good or very good condition, Enersource has several hundred transformers with a poor or very poor health index. As a result, the ACA suggests an initial replacement of 196 transformers. This initial surge in the replacement rate is caused by a large number of transformers that are overdue for replacement. After the first year, the ACA suggests gradually increasing the replacement rate from 119 to 180 units in fifteen years. After 15 years, the rate should be reduced.

According to the suggested replacement rates, after 40 years, 4,089 transformers will be replaced, which translates to an average replacement of 102 units per year. The replacement quantities are shown in Figure 10.2.6.2.

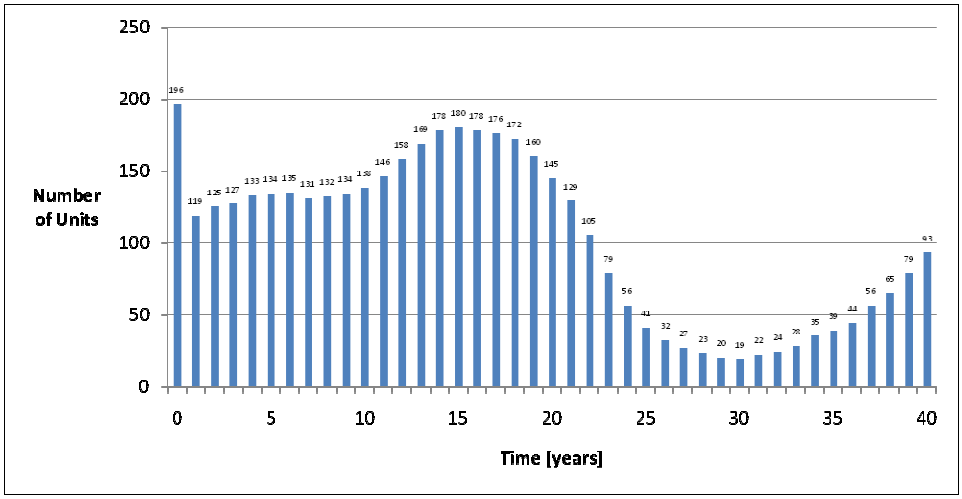


Figure 10.2.6.2: Vault Transformers - Recommended Replacement Rates

In 2010, through underground rebuilds, failures and spot replacements, Enersource replaced approximately twenty vault transformers, some of which were done under the PCB transformer replacement program. In 2011, approximately fifteen transformers were replaced. The 2012 budget and labour resources will allow for replacement of a similar number of vault transformers.

The current replacement rate of vault transformers is lower than the rate suggested by the ACA. After reviewing the ACA results, a secondary evaluation of the distribution data and the number of failures in the past was performed. It was observed that due to Enersource's practices and installation location on the transformers, the expected useful life of the vault transformers may be assumed longer than initially assumed. This is most likely because the units are sheltered from external elements that degrade other outdoor transformers and cause them to fail earlier. Further evaluation of the results is required. It is reasonable that the future useful life of vault transformers, based on more field and asset data, may require to be updated.

However, Enersource recognizes that the current replacement rate is too low and will have to be increased. A future study will determine the new replacement rate. Currently, Enersource's reliability is not greatly affected by the vault transformer failures since typical installations supply

only one customer and the majority of the population still has a good or very good health index. In the future, the plan is to increase main feeder and local distribution feeder cable rebuild projects and replace aging vault transformers under these projects.

10.2.7 Pad Mounted Switchgear

Air insulated pad mounted switchgear units are one of the types of underground distribution switches used on the system. The main purpose of the underground switches is to control the flow of the current and protect cables, transformers and other components from over current under fault conditions.

Internal switches or fuses are air insulated and are installed inside a self-supporting metal enclosure. Switchgear units are typically installed above grade on a concrete foundation, typically on park property, a school, or sometimes on the city boulevard.

The switchgear unit consists of a low profile pad mounted enclosure with various internal compartments housing cable terminations, switches, and protection equipment. Depending on the internal configuration, the pad mounted switchgear can contain various amounts of 600A three pole loadbreak switches, or hook-stick operated single phase power fuses rated up to 200A.

In the past, switchgear units with two different voltage ratings were installed: 15kV and 25kV. In 1992, to reduce inventory levels, all new switchgear installations were standardized to 27.6kV.

Typically, a single switchgear unit in a residential area can supply power up to 400 customers; therefore, if the unit fails, the effect on reliability is significant with respect to the number of customers. Additionally, some failures are intermittent, making it extremely difficult and time consuming to find the faulty unit. In such cases, the customers are exposed to several short outages, negatively affecting the frequency, that is, the SAIFI, portion of reliability.

As of December, 2010, there were 784 pad mounted switchgear units installed. The average age of the population is 19 years. The ACA study assumes that 20% of the population will fail by 25 years and 99% of the population will fail by 45 years. According to ACA, approximately 26% of the switchgear population is 25 years or older.

The trend rate of installation for pad mounted switchgear units is similar to the trend of the single phase pad mounted transformers. The installation rate was fairly low up to the mid 1980's. After that, the installation rate kept increasing until the early 1990`s. Following that, the rate has returned to a typical installation rate. The demographic breakdown of the pad mounted switchgear is illustrated in Figure 10.2.7.1.

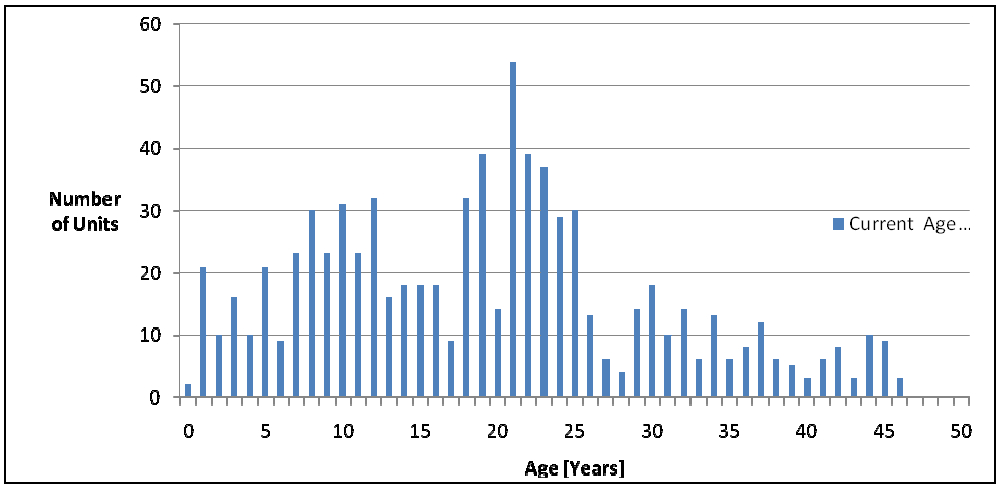


Figure 10.2.7.1: Pad Mounted Switchgear Age Distribution

According to the ACA, although 76% of the pad mounted switchgear units are in good or very good condition, Enersource has over 13% of the population has a poor or very poor health index. As a result, the report suggests an initial replacement of 31 units. After the first year, the report suggests replacing between 14 and 30 pad mounted switchgear units.

According to the suggested replacement rates, after 40 years, 888 switchgears will be replaced. In contrast to historical rates of installation, for the next 40 years Enersource will be replacing an average of 22 units each year. The replacement quantities are shown in Figure 10.2.7.2.

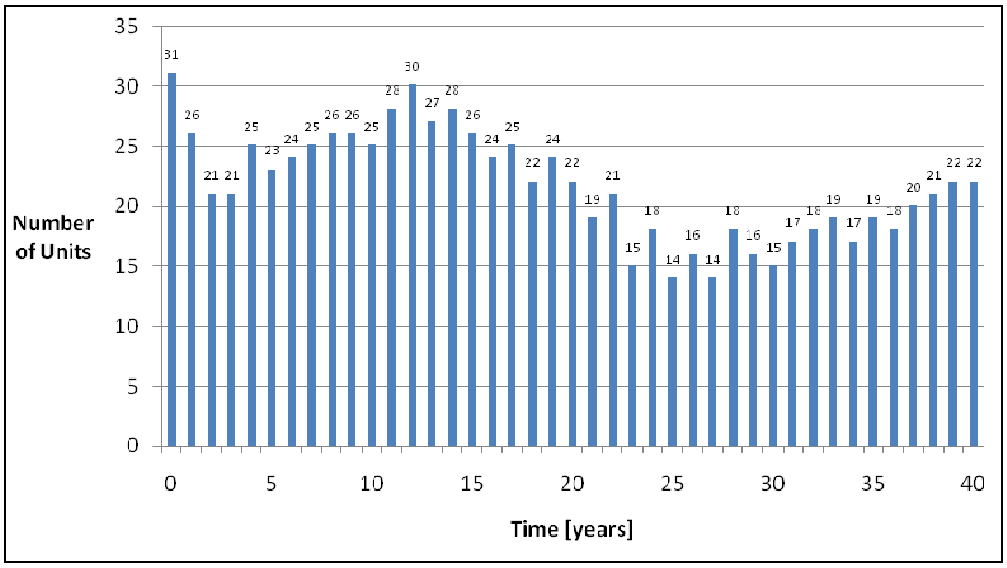


Figure 10.2.7.2: Pad Mounted Switchgear - Recommended Replacement Rates

In 2010 and 2011, through underground rebuilds, failures and spot replacements, Enersource replaced approximately 25 pad mounted switchgear units each year. The 2012 budget and labour resources will allow for replacement of a similar number of switchgear units

The 2012 replacement rate of the pad mounted switchgear is lower than the rate suggested by the ACA. Further adjustment to the replacement rate is needed to match the suggested ACA replacement levels. Additionally, when undertaking underground cable rebuilds in the area, effort is being made to reconfigure the distribution system to remove the switchgear altogether.

10.2.8 Overhead Switches

The primary function of these switches is to allow the isolation of line sections or equipment for maintenance, safety or other operating requirements. In general, switches consist of mechanically movable copper blades, supported on insulators, and mounted on metal bases. Their operating mechanism can be either a simple hook stick or a manually driven mechanism to move the ganged contacts. Air serves as the insulating medium between contacts when these switches are in the open position.

All of the overhead loadbreak switches used are rated for 600A continuous current and are capable of interrupting full current when opened under load. In addition to the loadbreak switches, Enersource also uses 900A in-line solid blade disconnect switches. These devices are not loadbreak and require to be manually operated from a bucket truck.

The majority of the switches installed are manually operated; however, a project is in place to install motor operators on switches at key locations to aid in the prompt restoration of power in case of an outage.

For the purpose of the ACA, the overhead switches were divided into three main categories: 44kV loadbreak switches, 27.6kV loadbreak switches, and in-line disconnect switches. Depending on the location, some units are located in critical points in the system. Their failure could result in a power interruption for several thousand customers; thus, the reliability impact from an overhead switch failure is very significant.

At the end of 2010 there were 295 - 44kV loadbreak switches, 221 - 27.6 loadbreak switches and 2,123 in-line disconnect switches. The average age of the population is eighteen, fifteen and eighteen years, respectively. The ACA assumes that 20% of the population will fail by 40 years and 99% of the population will fail by 55 years. In line with this assumption, according to ACA, between 4% and 8% of the overhead switch population is 40 years or older.

The rate of installation of 44kV switches was increasing until the late 1980`s. After that, the rate started to stabilize and is now fewer than five switches per year as the system matures. The installation rate of the 27.6kV loadbreak switches and in-line disconnect switches has been gradually increasing. The demographic breakdown of 44kV switches, 27.6kV switches, and in-line disconnect switches is shown in Figures 10.2.8.1, 10.2.8.2, and 10.2.8.3 respectively.

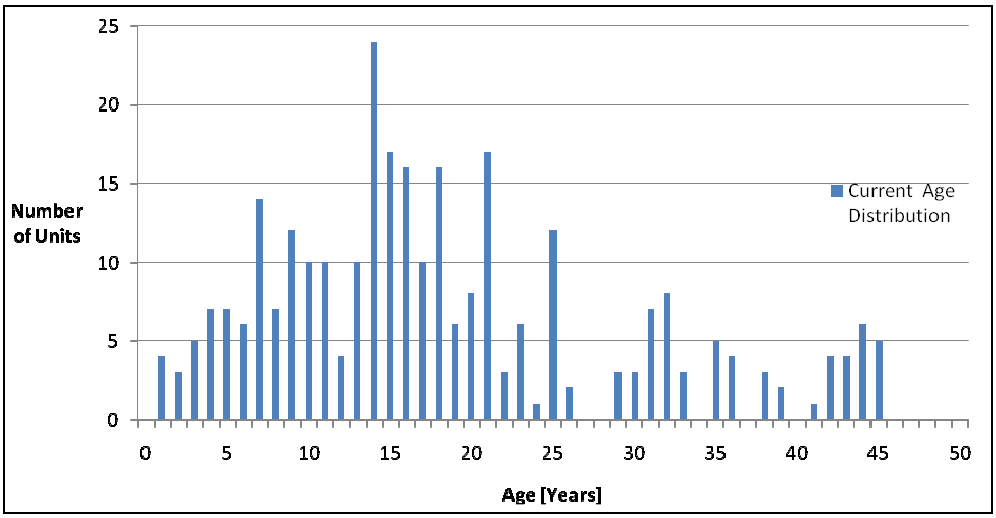


Figure 10.2.8.1: 44kV Loadbreak Switch Age Distribution

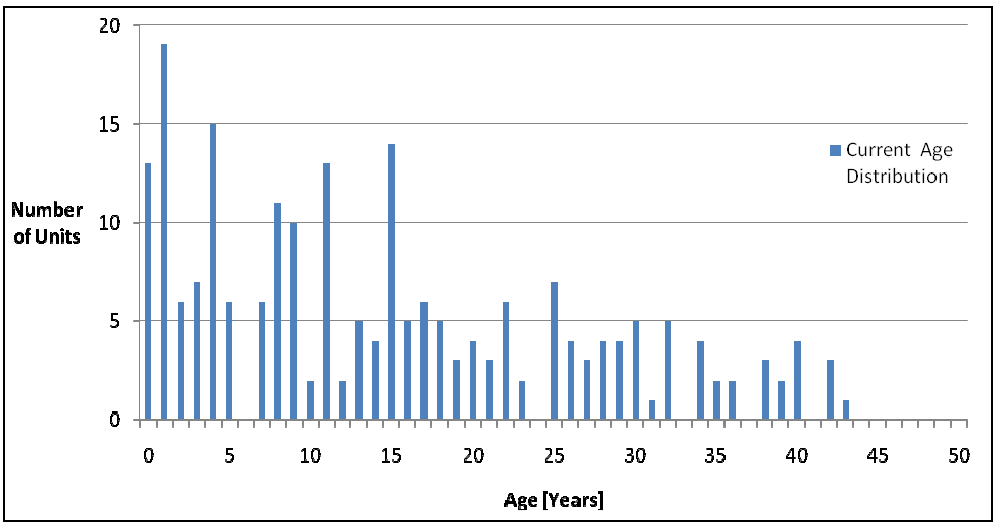


Figure 10.2.8.2: 27.6kV Loadbreak Switch Age Distribution

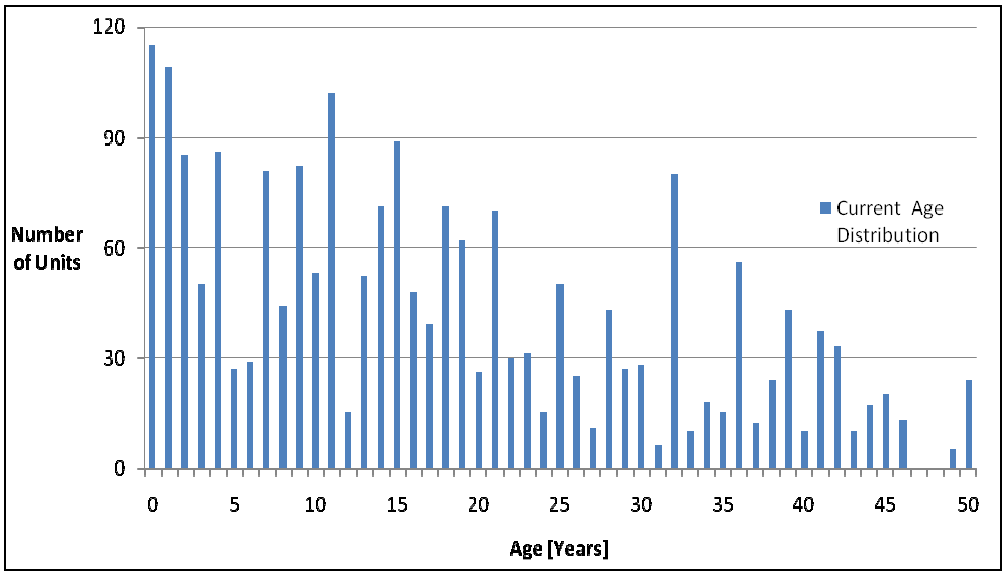


Figure 10.2.8.3: In-line Disconnect Switch Age Distribution

According to the ACA, 95% or more of the overhead switches are in good or very good condition. In addition, only 2% of the in-line switches have a health index below fair.

The ACA suggests an initial replacement rate on the 44kV system of four units, then increasing the rate to 22 switches. After that, the suggested replacement rate drops to one switch per year. The suggested replacement rate on the 27.6kV system is similar in pattern, except the number of switches to be replaced is lower in the earlier stage and higher after 21 years. The ACA also suggests replacing an initial seventeen in-line switches and increasing the rate to 64 units in 35 years.

According to the suggested replacement rates, after 40 years, 262 - 44kV loadbreak switches, 139 - 27.6kV loadbreak switches and 1,572 in-line disconnect switches will be replaced. In contrast with the historical rate of installations, for the next 40 years Enersource will be replacing an average of seven 44kV switches, three 27.6kV switches, and 39 in-line Disconnect Switches each year. The replacement quantities are shown in Figures 10.2.8.4, 10.2.8.5, and 10.2.8.6, respectively.

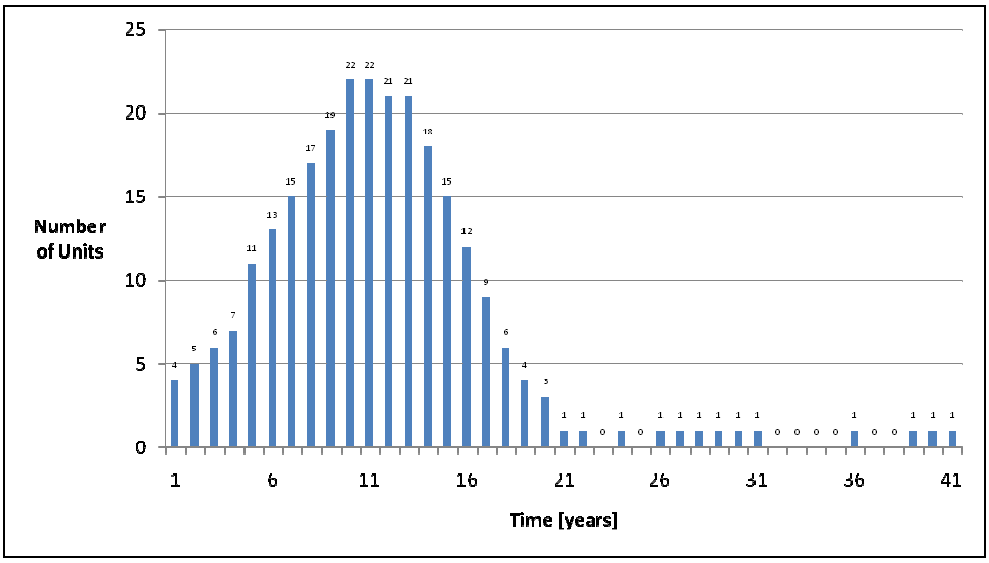


Figure 10.2.8.4: 44kV Loadbreak Switches - Recommended Replacement Rates

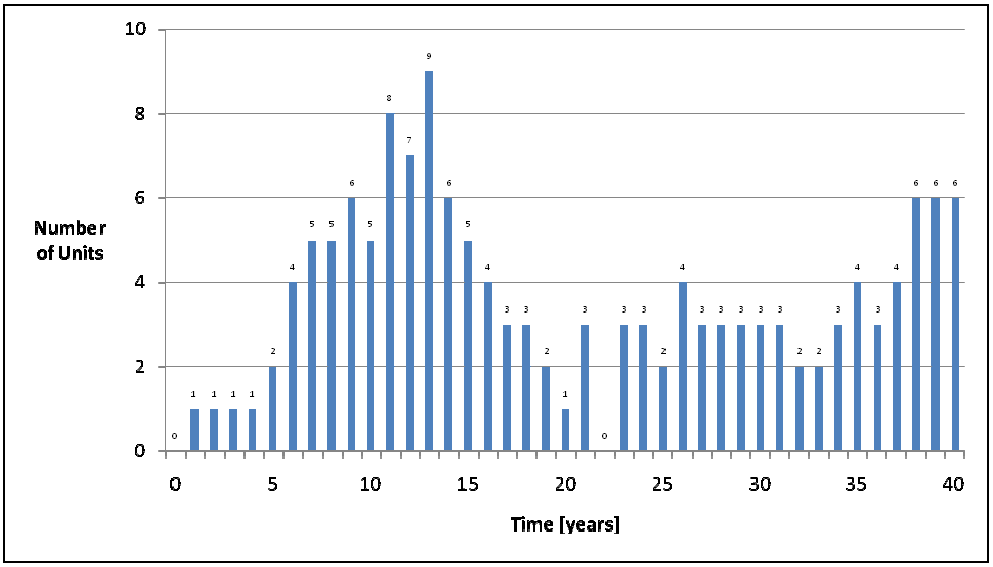


Figure 10.2.8.5: 27.6kV Loadbreak Switches - Recommended Replacement Rates

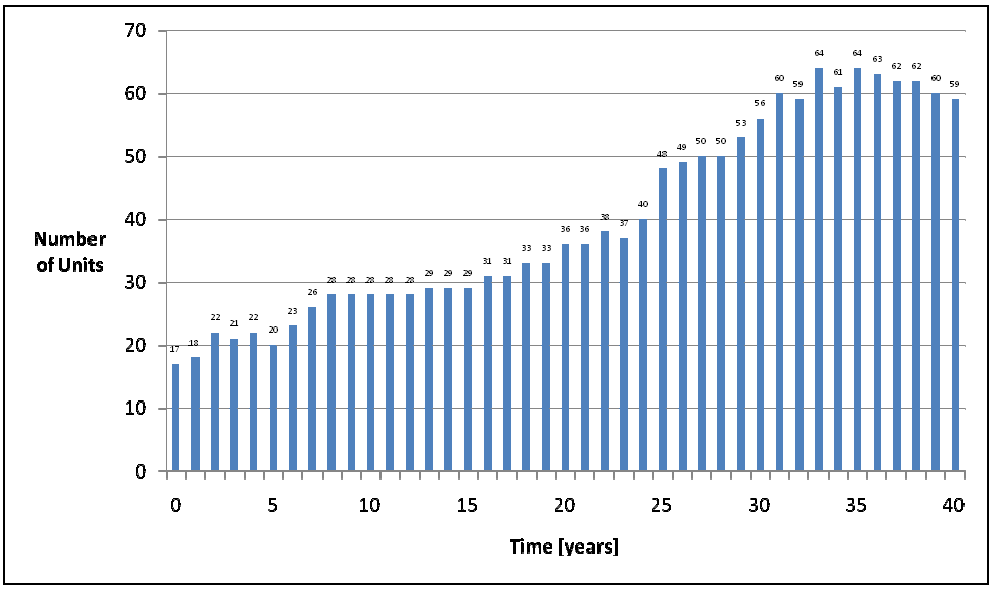


Figure 10.2.8.6: In-line Disconnect Switches - Recommended Replacements

On average, through overhead rebuilds, failures and spot replacements, Enersource replaces approximately 2 of the 27.6kV loadbreak switches and between 70 and 120 in-line disconnect switches annually. In 2010 or 2011 no 44kV loadbreak switches were replaced.

The current replacement rate of the overhead 27.6kV loadbreak switches is slightly higher than the recommended replacement rate. This is due to field inspections that identified defective switches or because of an overhead rebuild in the area, which covered replacement of the entire overhead system in the area.

In 2011, Enersource replaced 68 in-line disconnect switches. That number is higher than the number recommended by the ACA. Most of the in-line switches were replaced because of field inspections or from infra red scans. If a single switch is identified as defective, as a part of work bundling, the maintenance crew will replace all three switches of the same circuit; therefore, the total number of switches replaced is higher than the recommended replacement quantity.

The current replacement rate for the overhead loadbreak switches is consistent with the recommended replacement rate. The replacement rate for the overhead in-line switches will be monitored in the future and further studies of equipment failures will be examined to ensure that the rate is adequate.

10.2.9 Underground Primary Cables

Primary underground conductors are used to transport power from either 44kV or 16/27.6kV TS to an MS and then to the distribution transformers at 8/13.8 or 2.4/4.16 kV, depending on the location in the city. The primary cables are installed within the city boulevard, either directly buried or installed in a separate 100mm direct-buried PVC duct.

Distribution underground feeder cables are one of the more challenging assets for electricity systems, from a condition assessment and asset management viewpoint. Most often, they are considered to be the most expensive components, due to the high cost of materials and very high cost of installation and maintenance.

It is very difficult, and therefore very expensive, to obtain meaningful condition information for buried cables. Underground cable systems, unlike overhead lines, do not suffer from weather induced faults and have better reliability records.

For the purpose of the AMP, the primary underground cables are separated into two categories:

- Main Feeder Cables (all 350 to 1,000 kcmil Main Feeder Distribution and Subtransmission cables) and
- Local Distribution Feeder Cables (all 250 kcmil or smaller distribution cables)

In the past, different sizes and ratings of the cables were installed. In 1993, to reduce inventory levels, all distribution main feeder cables were standardized to 1000kcmil, 28kV and all local distribution cables were standardized to 1/0, 28kV.

The subtransmission main feeder cables typically supply an MS. As a result, a failure of a cable supplying a single station may result in disruption of power for up to 5,000 customers. In addition, the failed cable will cause a temporary interruption to the TS station that supplies tens of thousands of customers. Main feeder cables are typically supplying several switchgear units and can deliver power to up to 700 customers each. The local distribution feeder cable is connected to the pad mounted switchgear units or the overhead distribution system and typically will supply up to 400 customers. Cable failures will result in a power outage to all customers connected and typically will momentarily trip the MS breaker as the fuse typically isolates the fault.

As of the end of 2010, there were 1,283km of main feeder cables and 5,081km of local distribution feeder cables. The average age of the population is approximately 19 and 17 years, respectively. The ACA assumes that 20% of the population will fail by 40 years and 99% of the population will fail by 55 years.

As shown in Figures 10.2.9.1 and 10.2.9.2, the rates of installation of underground cables have varied widely over the past 50 years. The installation rates were gradually increasing until the early 1990`s. After that, installation rates stabilized in the mid 1990`s. Finally, in late 1990`s and early 2000`s cable installation rates started to increase again and reached the highest level in early 2000`s. Since then, the installation rates have been gradually declining.

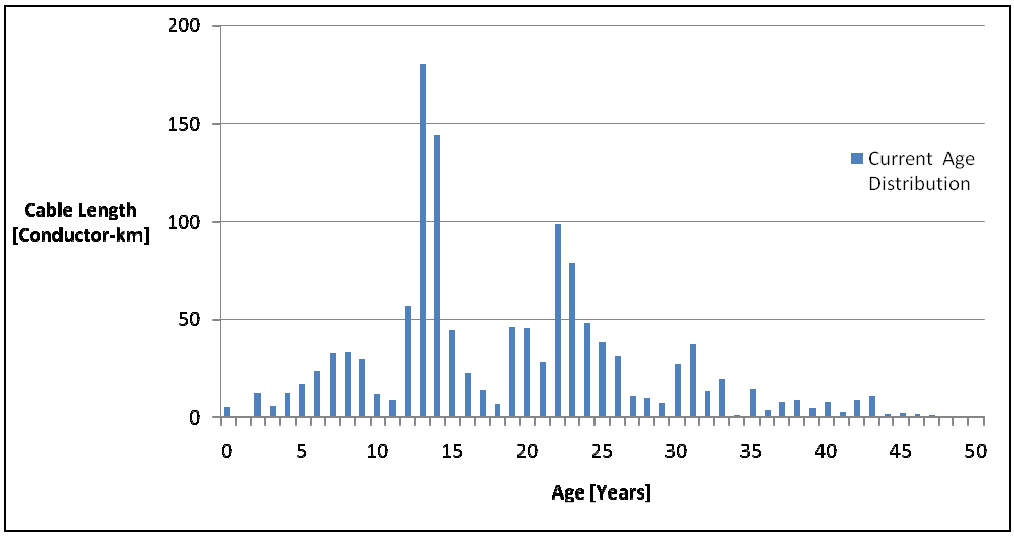


Figure 10.2.9.1: Main Feeder Cable - Age Distribution

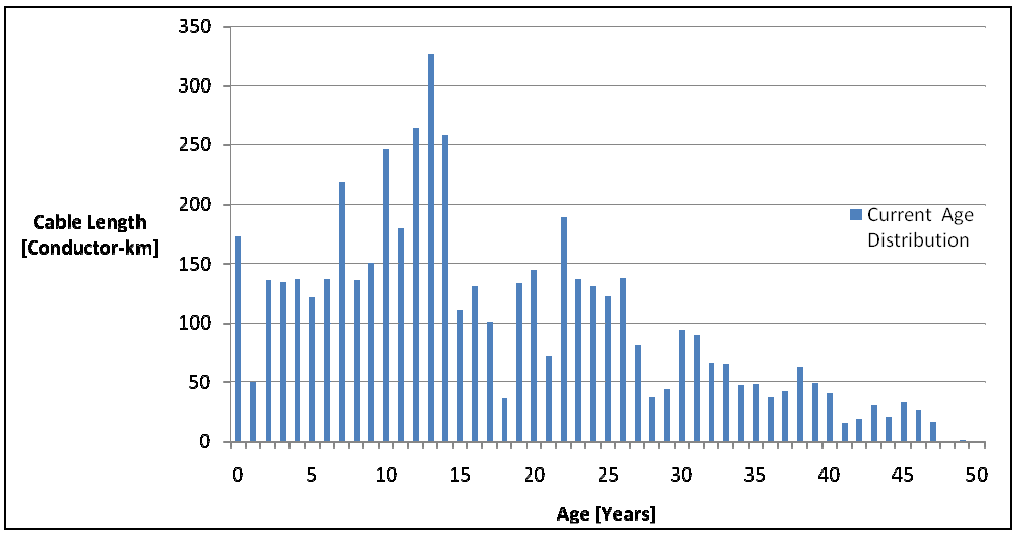


Figure 10.2.9.2: Local Distribution Feeder Cable - Age Distribution

According to the ACA, more than 95% of the underground cables are in good or very good condition. In addition, the ACA pointed out that almost 3km of main feeder cables and 50km of local distribution feeder cables, are in very poor or poor condition. The suggested replacement rate for the main feeder cables is starting at 5km per year and it will gradually increase to 48km in 25 years. For the local distribution feeder cable, the suggested rate starts at 33km per year and it increases to 167km in 35 years.

According to the suggested replacement rates, after 40 years, 1,186km of main feeder cables and 4,187km of local distribution feeder cables will be replaced. In contrast with the historical rate of installations, for the next 40 years Enersource will be replacing an average of 30km of main feeder cables and 105km of local distribution feeder cables each year. The replacement rates are shown in Figures 10.2.9.3 and 10.2.9.4.

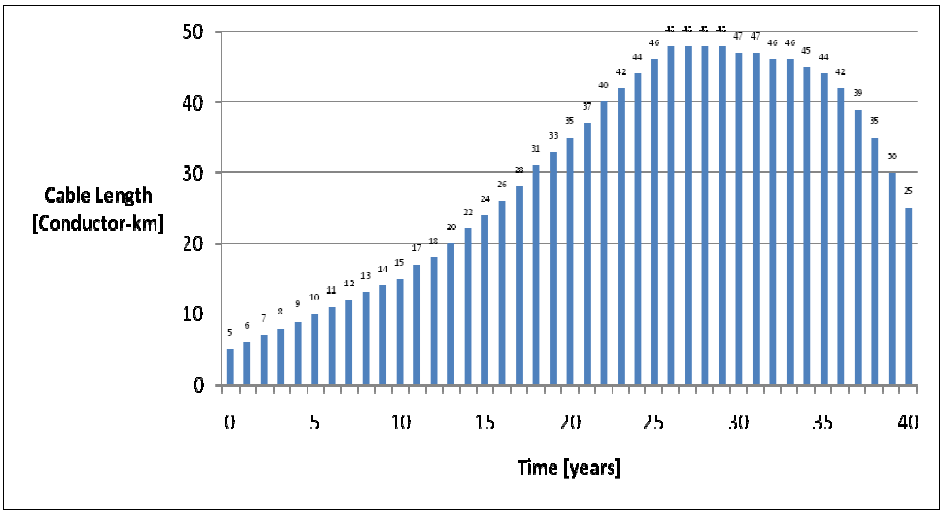


Figure 10.2.9.3: Main Feeder Cable - Recommended Replacement Rates

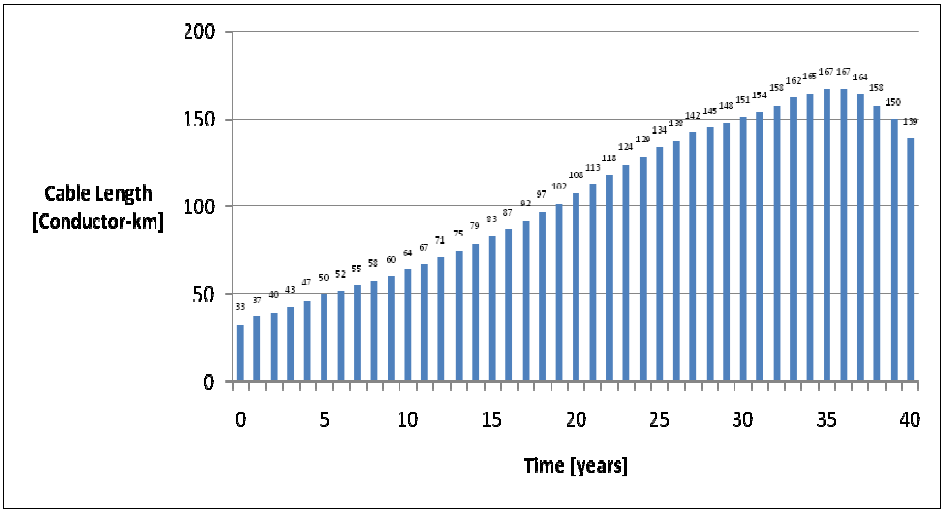


Figure 10.2.9.4: Local Distribution Feeder Cable - Recommended Replacement Rates

In 2010 and 2011, through underground rebuilds, failures and spot replacements, Enersource replaced approximately 5km of main feeder cables and 30km of local distribution feeder cables annually. The 2012 budget and labour resources allow for the replacement of approximately the same quantity of the cables.

In the past few years, the number of cable failures has increased significantly, which contributes to a decline in reliability. In 2011, 51% of the power outages that occurred were caused by equipment failures. Furthermore, failures of the underground power cables accounted for 60% of equipment failures.

Based on an additional evaluation of the number of failures and associated ages of the equipment, it was concluded that the expected useful life of the underground cables installed prior to 1987 is shorter than 40 years. After 1987, several changes were done to the materials used in cables as well as installation practices, which enhanced performance of the cable and prolonged its useful life to 40 years or more. For the purpose of the first iteration of the ACA, the average useful life for all cables was assumed to be 40 years. In the future revisions of the ACA, more accurate ages for cables installed prior to and past 1987 will be assigned.

The current replacement rate of the main feeder cables is consistent with the rate suggested by the ACA. In the near future, the replacement rate will have to be increased to match the rate suggested in the ACA in order to avoid aging assets past their expected life.

Currently, Enersource's reliability is not affected greatly by main feeder cable failures, since only a moderate number of main feeder cables fail each year. However, as noted previously, failures of local distribution feeder cables affect the reliability significantly. The ACA will have to be reviewed in the future to account for poor quality of cables manufactured before 1987, and recommended replacement rates for local distribution cables will probably be increased. The replacement rates for these cables will have to be increased every year to match the suggested ACA replacement rates.

10.2.10 Wood Poles

Poles serve as support structures for overhead conductors, switches, transformers and other devices. In addition to Enersource`s equipment, the poles often support streetlights and third party attachments such as telephone, cable TV and fiber communication cables. Poles are made of wood, concrete, metal or fiberglass. The vast majority of the poles on Enersource's system are wood or concrete. All poles are partially buried in the ground, and as a result they are self-supporting structures; nevertheless, there are locations where poles may need additional support, such as at dead ends or at corners.

Wood poles are one of the two main types of poles used. The poles installed in the past in Mississauga vary in sizes from 25 feet to 75 feet; however, to reduce the number of stocking sizes Enersource has standardized pole heights and classes. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances, and the presence of telecommunications facilities. The current preferred species for wood poles is Western Red Cedar.

Poles support bare overhead wires and other equipment. Failure of the pole is very serious, especially since the general public may come in contact with live conductors. In addition, depending on the number of circuits supported by the pole and the voltage, failure may disturb power to thousands of customers. Since the consequence of asset failure is significant, poles are proactively replaced prior to failure. As a result, failures of poles and pole line hardware are

tracked closely and there are several programs in place to assess the condition of the poles. Typically, poles don't fail unless they are exposed to extreme storms, they become old and deteriorated, or they are damaged in vehicle accidents, from animals such as woodpeckers or termites, or from fallen trees.

At the end of 2010, there were 12,812 wood poles installed. The average age of the population is 23 years. The ACA assumes that 20% of the population will fail by 45 years and 99% of the population will fail by 75 years. According to the ACA, 11% of the wood pole population is 45 years or older.

The trend rate of installation of wood poles is fairly constant throughout the past. The rate of installation used to be slightly higher in the 1970`s and 1980`s, and has started to stabilize since then. The demographic breakdown of the wood pole population is shown in Figure 10.2.10.1.

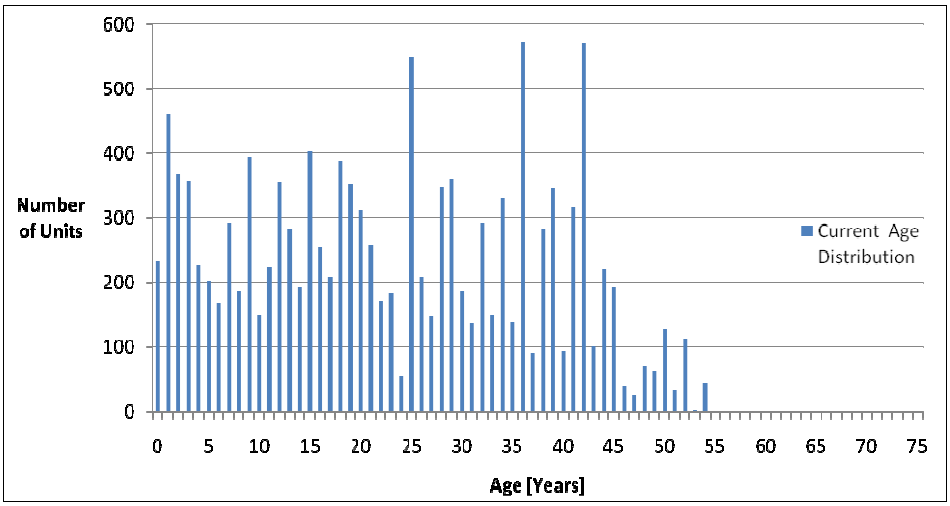


Figure 10.2.10.1: Wood Poles - Age Distribution

According to the ACA, over 95% of wood poles are in good or very good condition. The suggested replacement rate for the wood poles is starting at 58 units per year and it gradually increases to 262 units in 25 years.

According to the suggested replacement rates, after 40 years, 7,884 wood poles will be replaced. In contrast with the historical rate of installations, on average, for the next 40 years Enersource will be replacing 197 poles each year. The detailed replacement quantities are shown in Figure 10.2.10.2.

Historically, through overhead rebuilds, failures and spot replacements, Enersource, on average has replaced between 80 to130 wood poles per year. Many of the old wood poles on main roads are replaced with concrete ones since they offer better performance over time and have a longer useful life. In 2011, a large portion of the overhead maintenance resources had to be diverted to road project initiatives and other customer driven jobs, therefore approximately 40 wood poles were replaced. The 2012 budget and labour resources allow for the replacement of approximately the same number of wood poles.

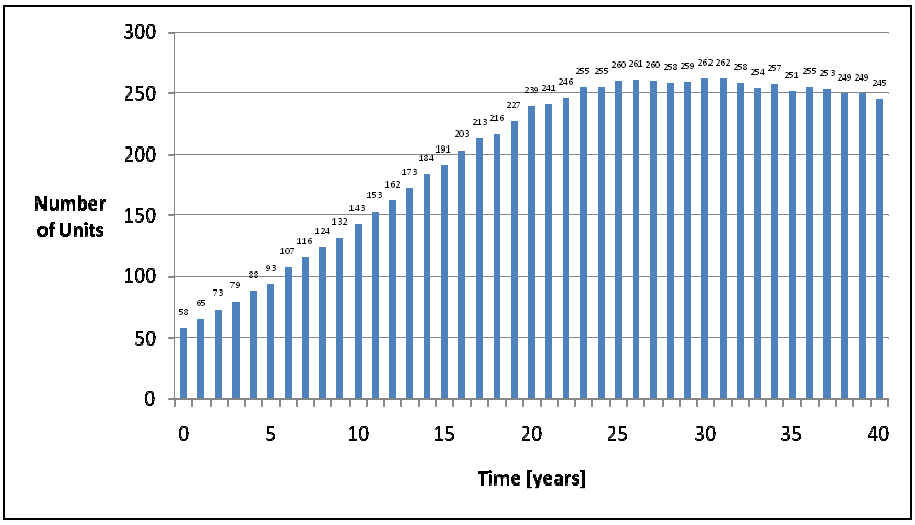


Figure 10.2.10.2: Wood Poles - Recommended Replacement Rates

The average current replacement rate is slightly higher than the rate suggested by the ACA; however it is lower than the 40 year average replacement rate. Future rates will have to be adjusted to maintain the replacement rate suggested by the ACA.

10.2.11 Concrete Poles

Concrete poles are the second main type of distribution support structures used. The smallest pole, 35 feet, is used to support a secondary service or span guy and the larger poles are used to support up to four primary circuits, overhead transformer banks, or loadbreak switches.

Concrete poles are typically installed in the city boulevard for all main feeder circuits along the major roadways. In addition, the concrete poles are used for distribution feed and secondary circuits in the central and northern part of the city.

As in the case of wood poles, concrete poles support bare overhead wires and other equipment. Failure of any pole is very serious, especially since the general public may come in contact with live conductors. In addition, since the majority of concrete poles support four circuits, the failure of a pole may disturb power to thousands of customers. Since the consequence of asset failure is significant, distribution and subtransmission poles are proactively replaced prior to failure. Typically, poles don't fail unless they are exposed to extreme storms, are old and deteriorated, or they are damaged in vehicle accidents.

At the end of 2010, there were 7,537 concrete distribution poles in service. The average age of the population is 18 years. The ACA assumes that 20% of the population will fail by 55 years and 99% of the population will fail by 80 years.

The trend rate of the installation of concrete poles has increased gradually, with an exception of the early 1990`s where the rate stabilized for approximately 10 years. The demographic breakdown of the concrete pole population is shown in Figure 10.2.11.1.

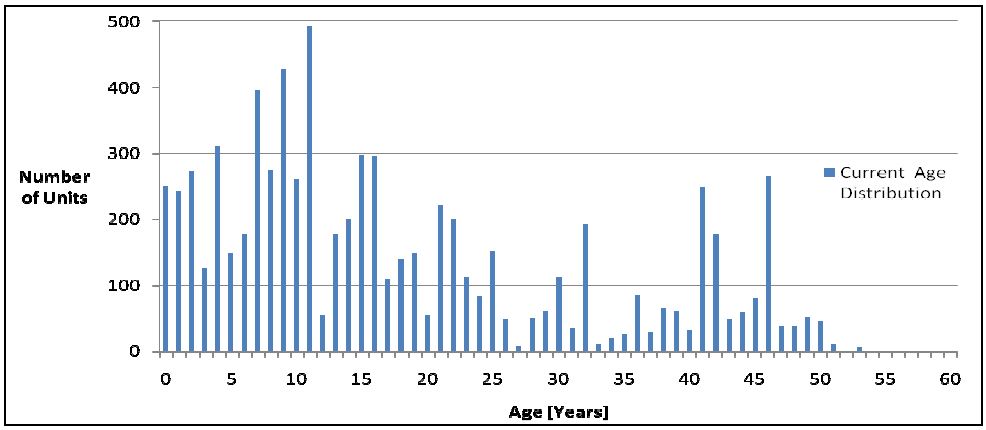


Figure 10.2.11.1: Concrete Poles - Age Distribution

According to the ACA, the majority of the population of concrete poles are in good or very good condition. The suggested replacement rate for the concrete poles is starting at four units per year and it gradually increases to 140 units in 40 years.

According to the suggested replacement rates, after 40 years, 2,605 concrete poles will be replaced. In contrast with the historical rate of installations, on average, for the next 40 years Enersource will be replacing 65 poles each year. The replacement quantities are shown in Figure 10.2.11.2.

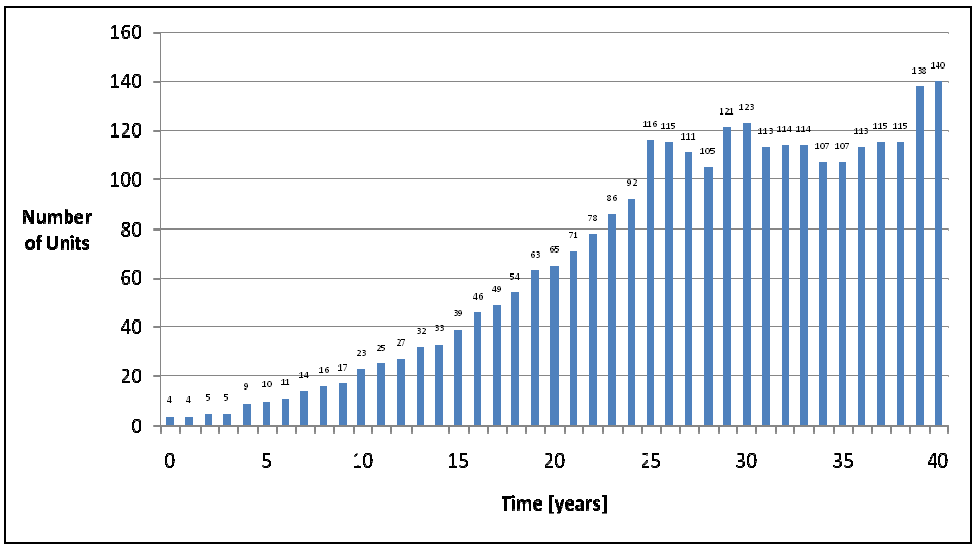


Figure 10.2.11.2: Concrete Poles - Recommended Replacement Rates

The current replacement rate for the concrete poles approximates the recommended replacement rate. The rate will be monitored in the future and further studies of equipment failures will be examined to ensure that the rate of replacement is appropriate.

10.3 Load Forecast

10.3.1 North 16/27.6kV System

In the North 16/27.6kV system, residential, industrial, and commercial development is still occurring and this trend is expected to continue over the next three to five years. This portion of the system is nearing TS capacity to adequately serve its customers. In the near future Enersource will require the addition of another Hydro One TS to service the area and to provide operational flexibility. Historical actual and forecasted peak demand for this area is shown below in Figure 10.3.1 North 16/27.6kV Distribution.

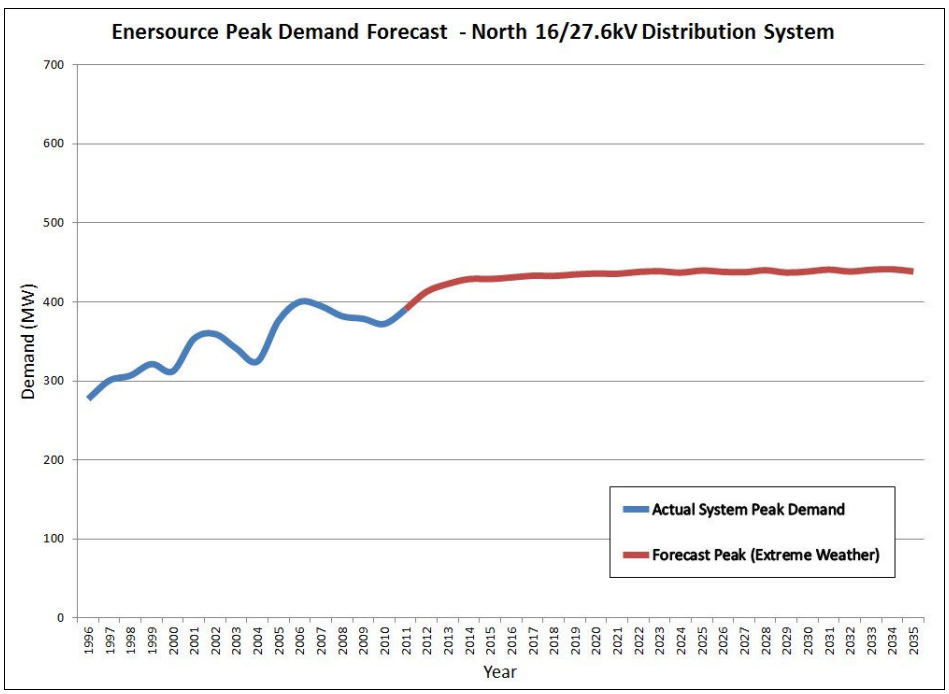


Figure 10.3.1 – Enersource Peak Demand Forecast - North 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035)

Year	2000	2005	2010	2015	2020	2025	2030	2035
Peak (MW)	312	376	372	429	435	439	439	439
Growth (%)		20.5%	-1.1%	15%	1.4%	0.9%	0%	0%

Table 10.3.1 – Enersource Peak Demand Forecast - North 16/27.6kV Distribution System – Extreme Weather Scenario (2000-2035)

10.3.2 South 16/27.6kV and 2.4/4.16kV Distribution

In the South 16/27.6kV region, redevelopment growth is projected through a number of new condominiums, industrial/commercial developments and at the water and wastewater pumping stations. The Lakeview, Clarkson, Herridge and Lorne Park pumping stations continue to expand and increase their load as more pumps and water mains are added. Historical actual and forecasted peak demand for this area is shown below in Figure 10.3.2 South 16/27.6kV Distribution.

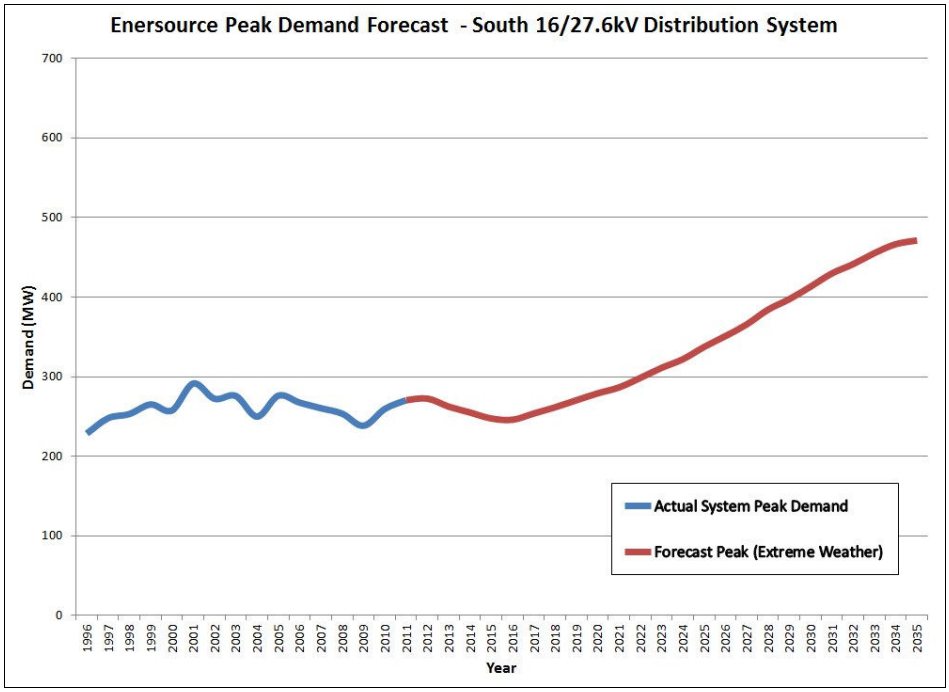


Figure 10.3.2 –Enersource Peak Demand Forecast - South 16/27.6kV Distribution System – Extreme Weather Scenario (1996-2035)

Year	2000	2005	2010	2015	2020	2025	2030	2035
Peak (MW)	258	276	260	248	279	338	413	471
Growth (%)		7%	-5.8%	-4.6%	12.5%	21%	22%	14%

Table 10.3.2 – Enersource Peak Demand Forecast – South 16/27.6kV Distribution System – Extreme Weather Scenario (2000-2035)

10.3.3 West 44kV Subtransmission and 8/13.8kV Distribution

The West 44kV system continues to serve predominantly condominium, residential and industrial/commercial loads. This part of the system will be further loaded by significant new condominium loads that are planned and under construction in the City Centre, along Eglinton Avenue in the west end of the city, and in new industrial/commercial loads in the Meadowvale area. Historical actual and forecasted peak demand for this area is shown below in Figure 10.3.3 West 44kV Subtransmission and 8/13.8kV Distribution Load Growth.

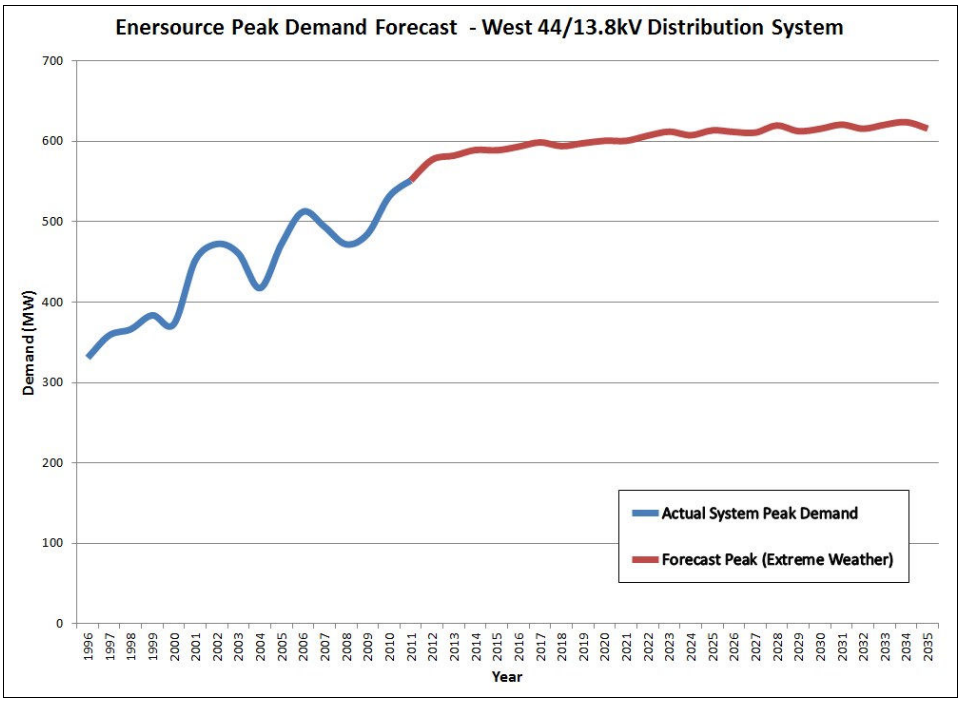


Figure 10.3.3 – Enersource Peak Demand Forecast - West 44/13.8kV Distribution System – Extreme Temperature Scenario (1996-2035)

Year	2000	2005	2010	2015	2020	2025	2030	2035
Peak (MW)	373	473	531	589	601	614	615	615
Growth (%)		27%	12%	11%	2%	2%	0%	0%

Table 10.3.3 – Enersource Peak Demand Forecast – West 44/13.8kV Distribution System – Extreme Weather Scenario (2000-2035)

10.3.4 East 44kV Subtransmission and 8/13.8kV Distribution

The East 44kV system continues to serve predominantly industrial/commercial loads. This part of the system is projected to experience moderate near term growth through additional new commercial and industrial loads from existing service upgrades and new customers. Historical actual and forecasted peak demand for this area is shown below in Figure 10.3.4 East 44kV Subtransmission and 8/13.8kV Distribution Load Growth.

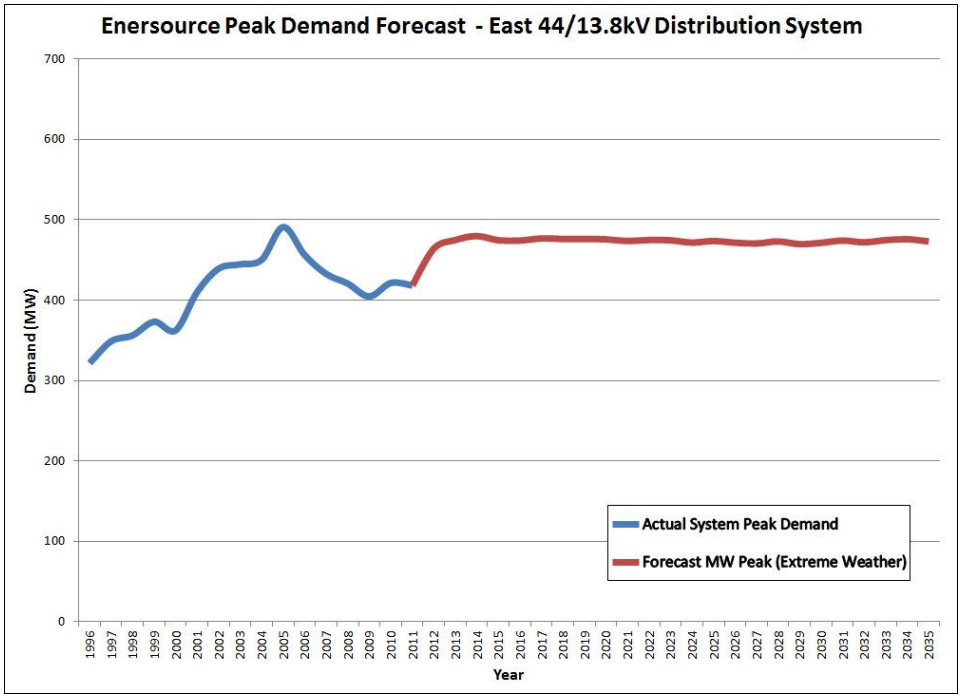


Figure 10.3.4 – Enersource Peak Demand Forecast - East 44/13.8kV Distribution System – Extreme Weather Scenario (1996-2035)

Year	2000	2005	2010	2015	2020	2025	2030	2035
Peak (MW)	362	491	421	475	475	473	471	473
Growth (%)		36%	-14%	13%	0%	0%	0%	0%

Table 10.3.4 – Enersource Peak Demand Forecast – East 44/13.8kV Distribution System – Extreme Weather Scenario (2000-2035)

10.4 Testing and Inspection Programs

10.4.1 Switchgear Dry Ice Cleaning

The distribution system consists of several important components to deliver electrical service to our customers. The distribution system has different types of switches to facilitate distribution of electrical load safely under normal and abnormal conditions. Enersource uses pad mounted switchgear on our underground primary distribution system. These switchgear units are one of the most important components of the distribution system. There are approximately 800 switchgear units in the distribution system.

These switchgear units are air insulated. The majority are installed near roadways to provide easy access for Enersource crews for switching operations. These units are exposed to road salt and other contaminants, which combined are a major cause of tracking leading to intermittent faults. These types of faults expose customers to multiple momentary power interruptions.

Enersource has a dry-ice maintenance program to clean the pad mounted switchgear units to mitigate tracking thus reducing equipment faults. Dry ice blast cleaning, which utilizes frozen carbon dioxide, offers a safe, effective and fast way to clean live electrical equipment. Dry Ice changes directly from a solid to a gas in normal atmospheric conditions without going through a wet liquid stage thereby offering a non-conductive, environmentally friendly method to clean switchgear. Since this technology can be utilized on live equipment it has a further benefit of not requiring customer outages.

In 2011 Enersource cleaned approximately 60 switchgear units using this method. At the same time these switchgear units were also inspected. All inspection findings are recorded and necessary actions are taken by the underground maintenance crew. This corrective maintenance reduces tracking thereby improving system reliability.

Figure 10.4.1.1: 27.6 kV Switchgear Dry Ice Cleaning

10.4.2 Overhead Infrared Inspection

Enersource has an annual overhead infrared inspection program which helps to detect defects in the electrical distribution system before they cause a major failure. The intent of the Infrared thermographic inspection program is to survey the electrical equipment, for hot spots, thus identifying potential electrical connection problems or defective equipment.

The infrared scanner converts heat radiation into a visible image. During the survey, digital infrared images and normal pictures are taken to depict the extent of the defect as well as the device location. The amount of heat emitted from the failing electrical component depends on both the ambient conditions and the actual current flow through that point. High electrical currents will stress most components and are easily detected.

Last year infrared inspection was performed on the entire overhead electrical distribution system; 20 hot spots were identified, a service order was generated for each hot spot, and all hot spots were reported to Enersource overhead maintenance crews for corrective action. An historical record of each hot spot is kept. A sample infrared inspection report is shown in Figure 10.4.2.1

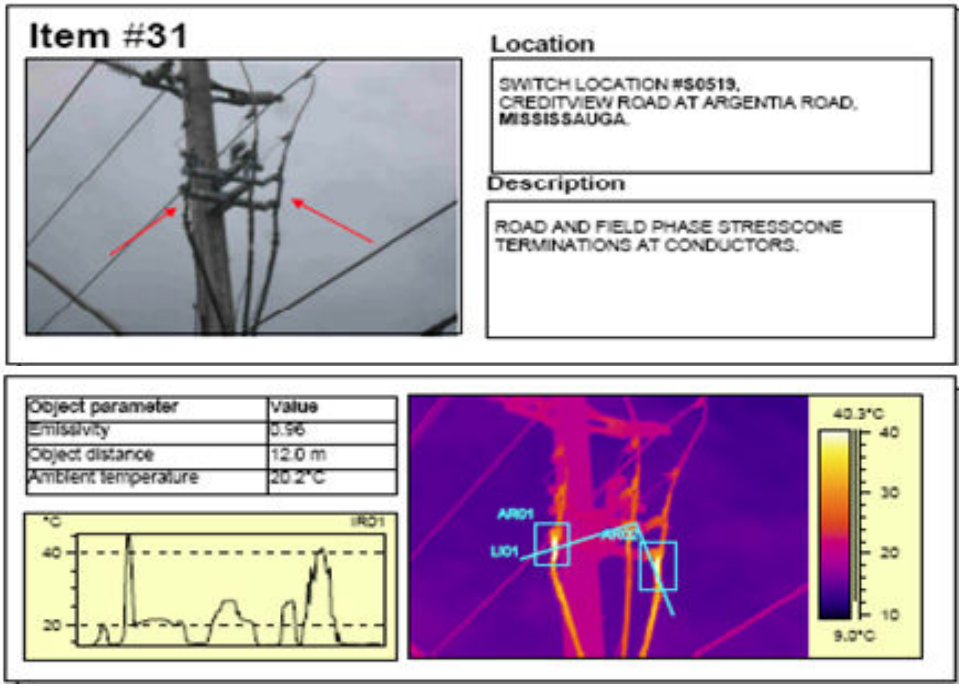


Figure 10.4.2.1: Sample Infrared Location Report

10.4.3 Overhead Loadbreak Switch Maintenance Program

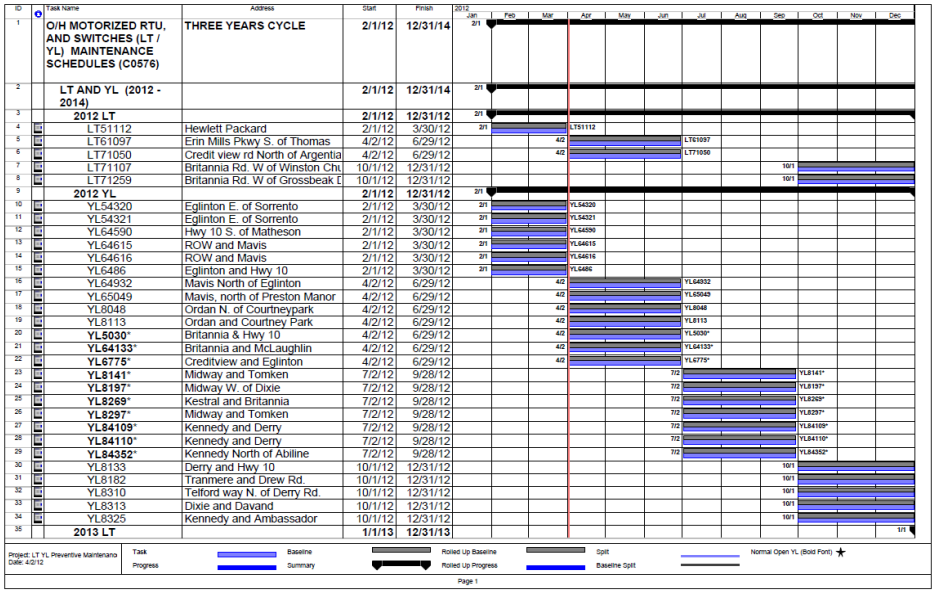
The power system has different types of switches to facilitate distribution of electrical energy. Load interrupters are one type of switch utilized in the overhead electrical power system. These switches are one of the most important components of our distribution system. Enersource has 92 motorized switches that we maintain in a three year cycle.

Enersource has a regular preventative maintenance program for the motorized load interrupter switches. The objective of this program is to perform preventive maintenance to preserve the switches' performance over its expected life.

During the maintenance of 44kV & 27.6kV loadbreak switches the following tasks are performed:

- inspection of the switch
- all necessary maintenance is performed
- grounding check
- check the minimum clearance between shut contact and interrupting unit
- check all contacts , clean contacts if necessary
- check handle location
- check pipe for couplings and adjustments
- check location and connection of ground strap
- check SCADA operation
- record of the maintenance is stored

In 2011, Enersource maintained 30 motorized switches, all necessary maintenance was done, and we will continue to inspect and maintain 1/3 of the motorized switches annually.



ID	Task Name	Address	Start	Finish
1	**O/H MOTORIZED RTU, AND SWITCHES (LT / YL) MAINTENANCE SCHEDULES (C0576)**	**THREE YEARS CYCLE**	**2/1/12**	**12/31/14**
2	**LT AND YL (2012 - 2014)**		**2/1/12**	**12/31/14**
3	**2012 LT**		**2/1/12**	**12/31/12**
4	LT51112	Hewlett Packard	2/1/12	3/30/12
5	LT61097	Erin Mills Pkwy S. of Thomas	4/2/12	6/29/12
6	LT71050	Credit view rd North of Argentia	4/2/12	6/29/12
7	LT71107	Britannia Rd. W of Winston Chu	10/1/12	12/31/12
8	LT71259	Britannia Rd. W of Grossbeak E	10/1/12	12/31/12
9	**2012 YL**		**2/1/12**	**12/31/12**
10	YL54320	Eglinton E. of Sorrento	2/1/12	3/30/12
11	YL54321	Eglinton E. of Sorrento	2/1/12	3/30/12
12	YL64590	Hwy 10 S. of Matheson	2/1/12	3/30/12
13	YL64615	ROW and Mavis	2/1/12	3/30/12
14	YL64616	ROW and Mavis	2/1/12	3/30/12
15	YL6486	Eglinton and Hwy 10	2/1/12	3/30/12
16	YL64932	Mavis North of Eglinton	4/2/12	6/29/12
17	YL65049	Mavis, north of Preston Manor	4/2/12	6/29/12
18	YL8048	Ordan N. of Courtneypark	4/2/12	6/29/12
19	YL8113	Ordan and Courtney Park	4/2/12	6/29/12
20	**YL5030***	Britannia & Hwy 10	4/2/12	6/29/12
21	**YL64133***	Britannia and McLaughlin	4/2/12	6/29/12
22	**YL6775***	Creditview and Eglinton	4/2/12	6/29/12
23	**YL8141***	Midway and Tomken	7/2/12	9/28/12
24	**YL8197***	Midway W. of Dixie	7/2/12	9/28/12
25	**YL8269***	Kestral and Britannia	7/2/12	9/28/12
26	**YL8297***	Midway and Tomken	7/2/12	9/28/12
27	**YL84109***	Kennedy and Derry	7/2/12	9/28/12
28	**YL84110***	Kennedy and Derry	7/2/12	9/28/12
29	**YL84352***	Kennedy North of Abiline	7/2/12	9/28/12
30	YL8133	Derry and Hwy 10	10/1/12	12/31/12
31	YL8182	Tranmere and Drew Rd.	10/1/12	12/31/12
32	YL8310	Telford way N. of Derry Rd.	10/1/12	12/31/12
33	YL8313	Dixie and Davand	10/1/12	12/31/12
34	YL8325	Kennedy and Ambassador	10/1/12	12/31/12
35	**2013 LT**		**1/1/13**	**12/31/13**

Figure 10.4.3.1: Sample of Motorized LT, YL and RTU 3 Year Maintenance Schedule

10.4.4 Station Maintenance Program

The maintenance programs of our municipal substations consist of the following:

- monthly inspections
- power transformer insulating oil testing and
- preventive maintenance

10.4.4.1 Monthly Inspections

The monthly inspections consist of visual inspections of the building and grounds as well as the electrical equipment inside the substations.

The building and grounds are checked for fence and gate / door integrity, vandalism, vegetation and environmental hazards such as transformer oil leaks or SF6 gas leaks.

The electrical equipment checks include inspection of the power transformer fans, battery and battery charger readings and protection relay flags.

All monthly inspection findings are recorded and actions taken as required.

10.4.4.2 Power Transformer Insulating Oil Testing

As part of the asset management of power transformers, Enersource collects oil samples at least once a year from every power transformer and tests them in accordance with the applicable standards. Regular sampling and testing of insulating oil is a valuable technique in a preventative maintenance program. Power transformer oil insulating tests results are maintained in a database and a report regarding the health of the power transformers is prepared annually.

Also observation of dissolved gases in the oil, and other oil properties, provides valuable information about transformer health.

Using proactive testing the life of the transformer can be maximized.

10.4.4.3 Preventive Maintenance

Substations electrical equipment is maintained on a regular schedule. The objective is to perform preventive maintenance approximately once every five years on each municipal power substation. This time interval can be reduced or increased based on operating conditions, equipment type and operating experience with the equipment.

Types of Substation Maintenance Activities include:

- transformer maintenance activities
- switchgear maintenance activities
- protection relays maintenance
- batteries & battery charger maintenance

10.4.4.3.1 Transformer Maintenance Activities

Transformer maintenance activities are based on the following documents and standards:

- manufacturer's instruction book
- IEEE 62-1995 IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus Part 1: Oil Filled Power Transformers, Regulators, and Reactors
- doble transformer maintenance and test guide

The following maintenance tasks are performed on every oil-filled substation transformer:

- inspect and test all controls, wiring, fans, alarms and gauges;
- in-depth inspection of transformer cooling system (check for leaks and proper operation)
- in-depth inspection of transformer bushings, cleaning, waxing if needed
- doble test transformer and bushings
- inspect pressure controls;
- inspect and test the tap changer

10.4.4.3.2 Switchgear Maintenance Activities

The substation switchgear maintenance is based on the manufacturer's recommendation and as a minimum shall consist of the following:

Busbar, enclosure and insulators maintenance;

- external visual inspection
- check and tighten connections
- check and clean enclosure

Circuit breaker maintenance

- lube, clean, adjust, align control mechanism
- contact resistance measurement
- test tripping and closing circuits

10.4.4.3.3 Protection Relays Maintenance

Three types of relays are used to clear the faults that occur in the distribution grid.

For electromechanical (GE IAC type) relays; the maintenance tasks shall include:

- visual Inspection
- mechanical adjustment and inspection
- electrical tests and adjustments

Electronic Relays (MCGG type) relays – since there are no moving parts in the electronic relays, there is no physical wear due to usage; the maintenance consists in secondary injection tests to

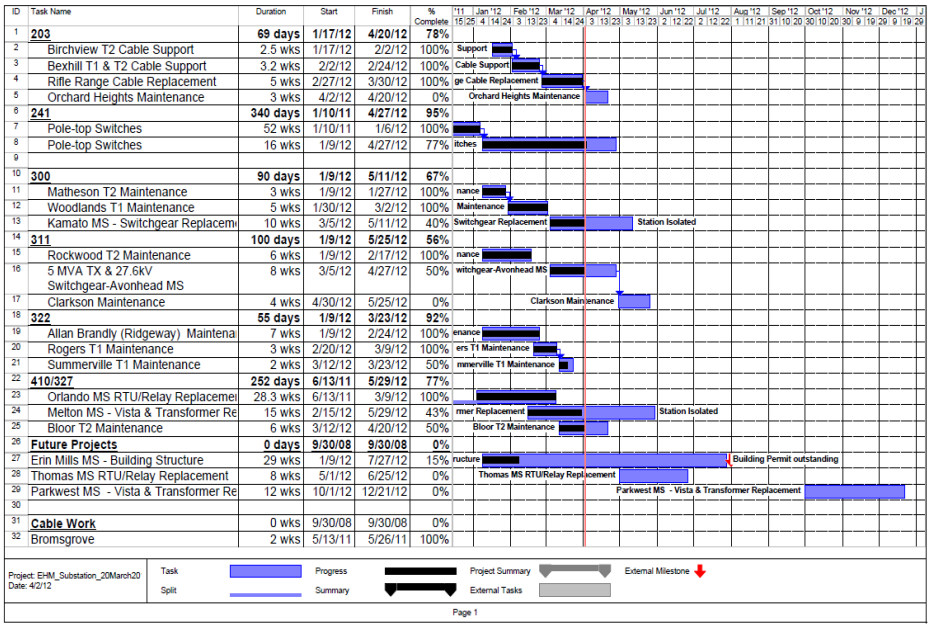
verify the tripping time accuracy of the relays. Microprocessor based (UR type) relays – only injection tests are performed as maintenance tasks.

10.4.4.3.4 Battery & Battery Charger Maintenance

The battery and battery charger maintenance consists of the following activities:

- record the room temperature
- measure and record the battery voltage
- measure and record each battery voltage
- record the charge current

Sample of Substations maintenance activities schedule can be found in Figure 10.4.4.1 below:



ID	Task Name	Duration	Start	Finish	% Complete
1	**203**	**69 days**	**1/17/12**	**4/20/12**	**78%**
2	Birchview T2 Cable Support	2.5 wks	1/17/12	2/2/12	100%
3	Bexhill T1 & T2 Cable Support	3.2 wks	2/2/12	2/24/12	100%
4	Rifle Range Cable Replacement	5 wks	2/27/12	3/30/12	100%
5	Orchard Heights Maintenance	3 wks	4/2/12	4/20/12	0%
6	**241**	**340 days**	**1/10/11**	**4/27/12**	**95%**
7	Pole-top Switches	52 wks	1/10/11	1/6/12	100%
8	Pole-top Switches	16 wks	1/9/12	4/27/12	77%
9					
10	**300**	**90 days**	**1/9/12**	**5/11/12**	**67%**
11	Matheson T2 Maintenance	3 wks	1/9/12	1/27/12	100%
12	Woodlands T1 Maintenance	5 wks	1/30/12	3/2/12	100%
13	Kamato MS - Switchgear Replacem	10 wks	3/5/12	5/11/12	40%
14	**311**	**100 days**	**1/9/12**	**5/25/12**	**56%**
15	Rockwood T2 Maintenance	6 wks	1/9/12	2/17/12	100%
16	5 MVA TX & 27.6kV Switchgear-Avonhead MS	8 wks	3/5/12	4/27/12	50%
17	Clarkson Maintenance	4 wks	4/30/12	5/25/12	0%
18	**322**	**55 days**	**1/9/12**	**3/23/12**	**92%**
19	Allan Brandly (Ridgeway) Maintena	7 wks	1/9/12	2/24/12	100%
20	Rogers T1 Maintenance	3 wks	2/20/12	3/9/12	100%
21	Summerville T1 Maintenance	2 wks	3/12/12	3/23/12	50%
22	**410/327**	**252 days**	**6/13/11**	**5/29/12**	**77%**
23	Orlando MS RTU/Relay Replacemen	28.3 wks	6/13/11	3/9/12	100%
24	Melton MS - Vista & Transformer Re	15 wks	2/15/12	5/29/12	43%
25	Bloor T2 Maintenance	6 wks	3/12/12	4/20/12	50%
26	**Future Projects**	**0 days**	**9/30/08**	**9/30/08**	**0%**
27	Erin Mills MS - Building Structure	29 wks	1/9/12	7/27/12	15%
28	Thomas MS RTU/Relay Replacement	8 wks	5/1/12	6/25/12	0%
29	Parkwest MS - Vista & Transformer Re	12 wks	10/1/12	12/21/12	0%
30					
31	**Cable Work**	0 wks	9/30/08	9/30/08	0%
32	Bromsgrove	2 wks	5/13/11	5/26/11	100%

Figure 10.4.4.1: Sample of Substations 2012 Maintenance Schedule

10.5 Integrated Operating Model

The IOM contains an Outage Management System (OMS), which records all activities, outages and problems associated with the power system, including information on equipment failures. Each record includes information on the type of equipment that has failed, its location in the field, the duration, and cause of the outage, as well as, the number of customers affected. The equipment failure information is analyzed by the Reliability department. Different programs, such as the cable and wood pole rebuilds, are selected and prioritized based on the reliability data from the IOM. Sometimes different queries and maps are created to help better understand and visualize affected

areas. Figure 10.5 shows a sample map illustrating cable failures and their effect on reliability over the past 10 years. In future, the plan is to use the reliability statistics from the equipment failures as one of the inputs into the updated ACA.

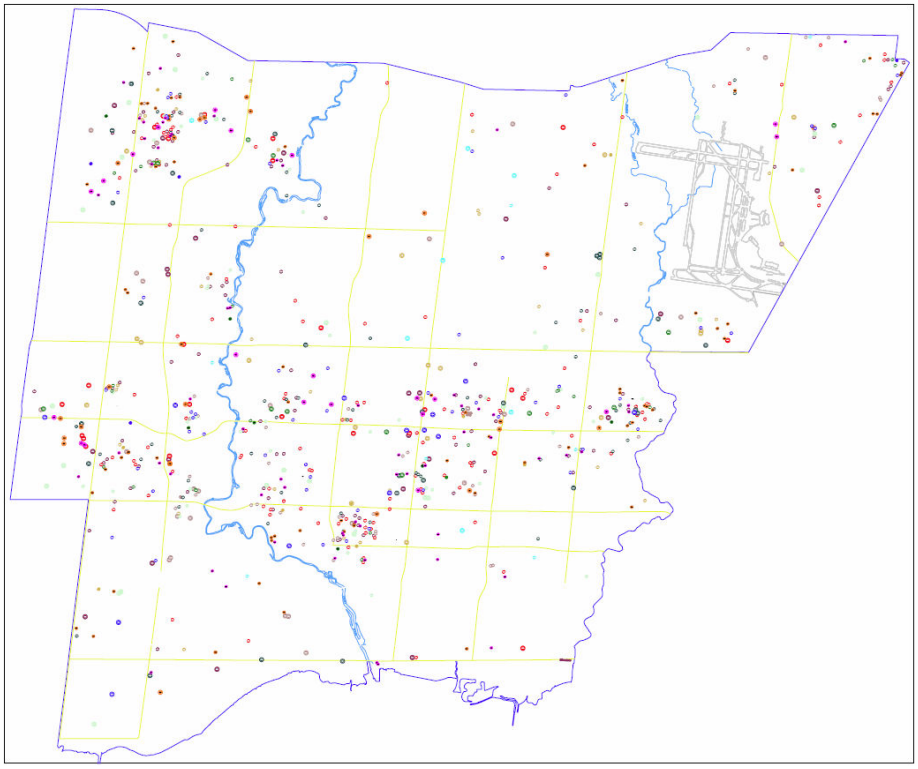


Figure 10.5: Cable Failure Map - IOM Data Source

10.6 Automated Mapping/Facilities Management/Geographical Information System

The AM/FM/GIS system is used to store attributes pertaining to Enersource's field equipment. Figure 10.6 shows a typical graphical user interface displaying a portion of the power system, along with all the attributes associated with the selected pad mounted transformer. Occasionally, a spatial map with a specific type or age of equipment is created from the AM/FM/GIS system. Such maps are used to aid the equipment inspections on the system. The information, such as equipment type, rating, voltage, age, manufacturer, and other technical data is used as an input to other studies. For the ACA, several databases were created containing the equipment attributes for all of the distribution and subtransmission hardware. The database is continually reviewed for further attributes for capture. The system is robust and flexible to accommodate evolving needs.

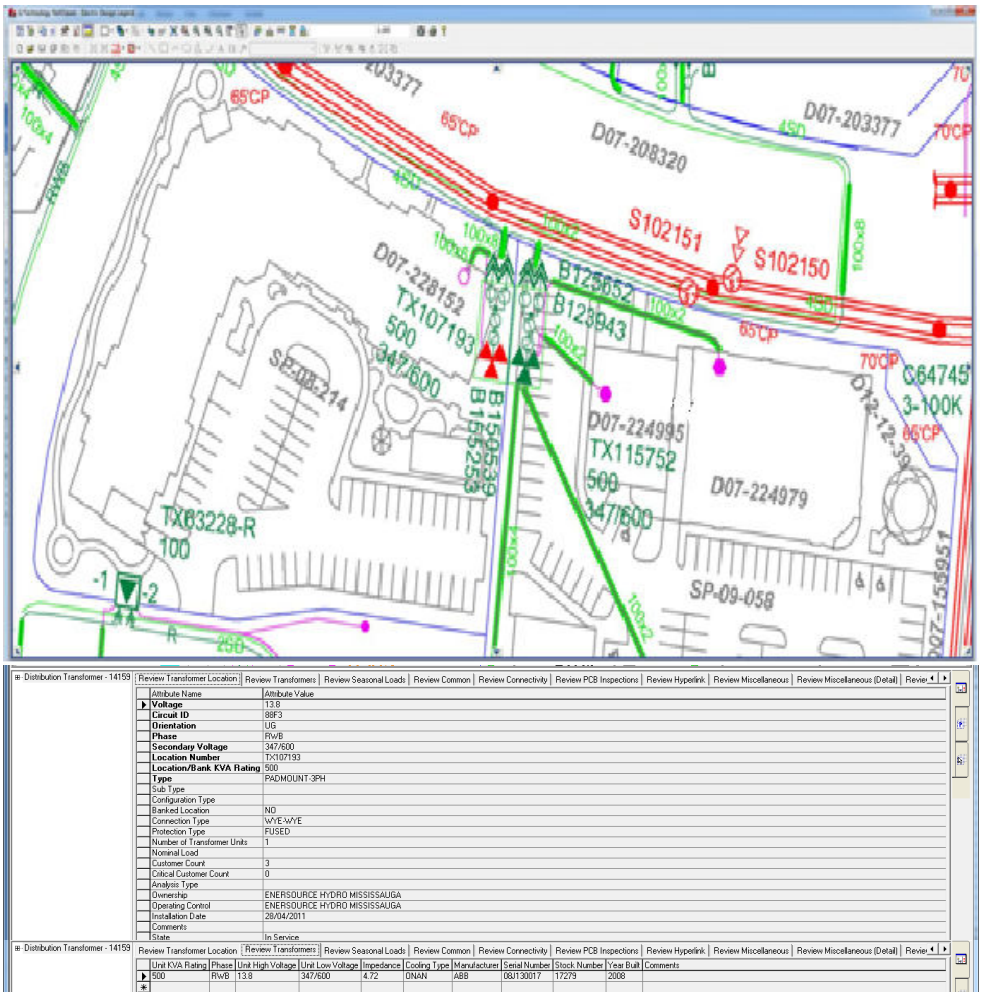


Figure 10.6: Sample Screenshot - G-Electric AM/FM

FUTURE PLANNING INITIATIVES

11. Planning Initiatives

11.1 System Planning Software - CYMDIST

Enersource is planning to utilize a program from CYME International Inc. called CYMDIST which performs power system analysis. This program is designed for system planning and simulating the behaviour of the system under different operating conditions and scenarios. The software, can perform power flow analysis, voltage drop and short circuit study, suggested switching optimization that will balance load for minimum losses or equalize feeder loading, displays effects of future load growth, perform contingency analysis, and do an arc flash hazard assessment and protective device coordination. Enersource plans to use CYMDIST to review the current system configuration, study it under different conditions, plan for system expansion and review proposed projects and changes to the power system.

11.2 Transformer Loading Tool

Enersource generates a transformer loading report based on a software application that provides aggregated power demand values for distribution transformers. The power demand information is collected from each individual account from our meter reading system. The connectivity information from the Automated Mapping/Facilities Management/Geographical Information System (AM/FM/GIS) is then used to associate each customer usage with the distribution transformer supplying the customer. The program can display either the maximum transformer load in any given day or it can provide an hourly breakdown of the power demand on a specific transformer. For the majority of the customer accounts, the consumption data is being captured on an hourly basis, but the program can display the transformer load by hour, day, month, quarter or annually. Enersource plans to utilize this report to monitor the loading of the distribution transformers to ensure they are utilized within acceptable limits. The loading data will be used as one of the inputs into the Asset Condition Assessment and will be a factor in calculating the health indexes of distribution transformers in future assessments.

11.3 Pole Testing Pilot Program

Pole testing and inspection program is a safe and economical pole management program that extends the life cycle of the wood pole system and allows for future planning of which poles to replace through the collection of data.

The objective of pole testing is to ensure our power system operates safely; to identify remaining life of the pole and collect useful data of the infrastructure.

We are in a process of establishing a pole testing and inspection program and we have selected three vendors to do a pilot project. The purpose of this pilot project is to test approximately 300 poles using two different pole testing methods.

- visual, sound and drill
- non destructive (using a resistograph)

The results of the pilot project will be reviewed by Enersource personnel, and based on the accuracy of the test results we will select the vendor with a high accuracy rate to run our pole testing and inspection program.

Work to be carried out:

- strength test and collect information required
- determine remaining life from the information gathered, including below-ground-line decay
- based on the field data determine the poles for remedial treatment

Equipment to be used:

- hammer to sound the pole on at least 3 sides in order to detect weaknesses
- drill 12.5 mm (1/2") holes to determine the internal weaknesses and such as advanced internal decay
- pole test to assess individual pole strength at ground line and at other weak locations, which are reachable from the ground
- resistograph to detect internal decay below and at ground line

End products:

- a set of information for each pole tested
- a list of poles to be replaced on the basis of their structural condition
- a digital database with all the relevant information
- a set of tables listing poles with potentially damaging defects such as extensive surface rot, mechanical damage, feathering, woodpecker damage and carpenter ant damage
- remaining pole life

Our ultimate goal is to start a pole testing and treatment program in 2012. We have approximately 13,000 wood poles in our system. We will test and treat 1/3 of these poles annually to help us prioritize our rebuild programs.

11.4 Ten Worst Feeder Study

The IOM outage reports are used to identify the worst performing feeders by analyzing historical outage data. Some of the measures typically looked at are: number of outages, total customer outage minutes, number of customers affected and number of auto reclosures. Feeders are ranked based on the outage types by weighting factors. The highest scores indicate feeders which are identified as needing additional review to determine action plans. This analysis assists in determining future overhead and underground maintenance programs. The studies will be continually updated in order to capture the reliability improvements in the areas that are being addressed and to find out what new areas should be considered in the future.

The historical worst feeders are shown in Figure 11.1 below.

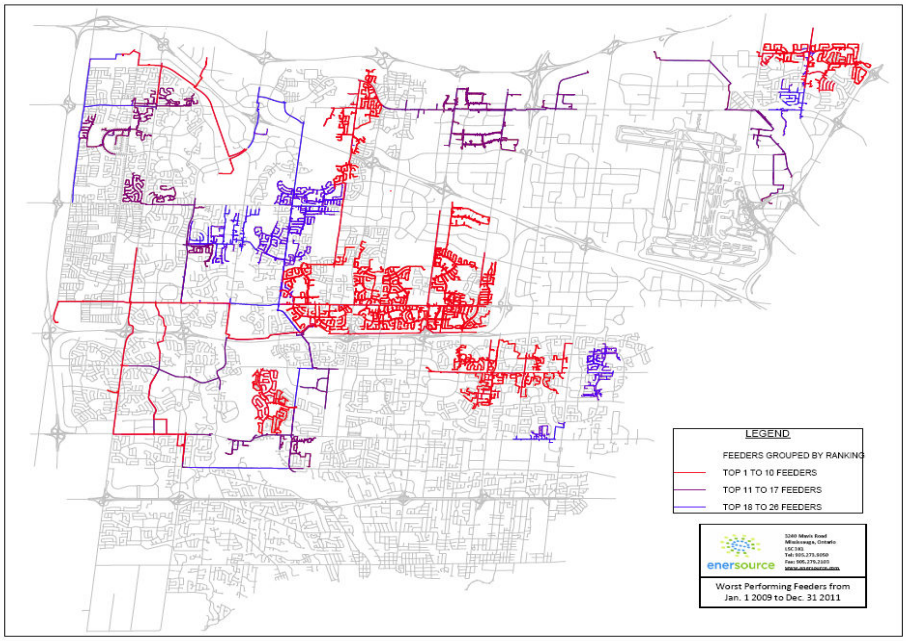


Figure 11.1 – Enersource Worst Feeder Map (2009-2011)

11.5 Major Outage Cause Study

Using the worst feeder study data the feeders are further analyzed to determine the cause or driving factor which caused the outage.

Examples of three (3) significant outage causes are:

- cable failure
- animal contact and
- weather related

Feeder failures due to cable failure are candidates for future underground subdivision rebuild programs are shown in Figure 11.2 below.

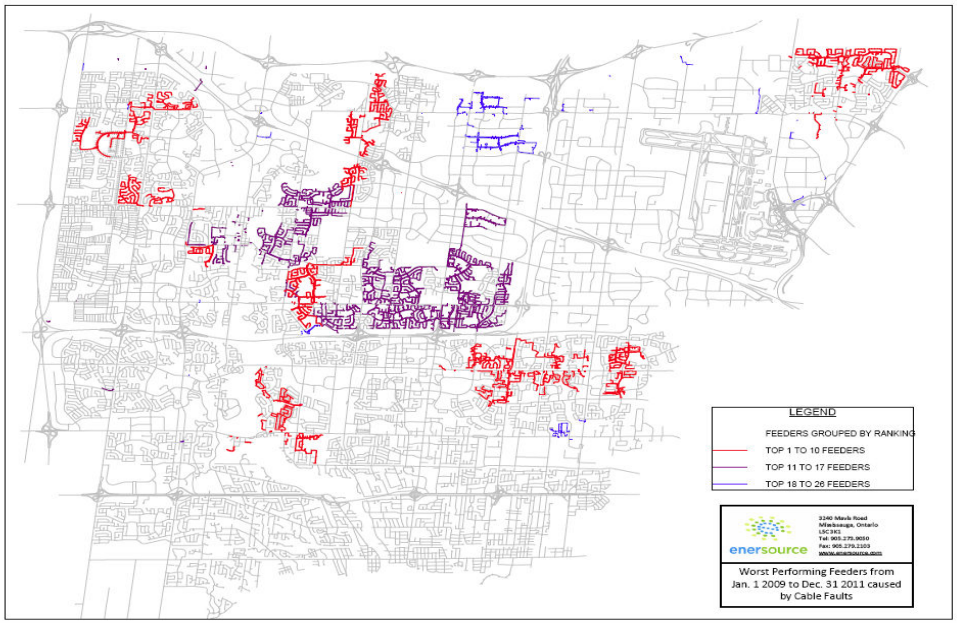


Figure 11.2 – Enersource Worst Feeder Due to Cable Faults (2009-2011)

Feeder failures due to animal contact are candidates for future maintenance programs such as vegetation management and animal protection programs are shown in Figure 11.3 below.

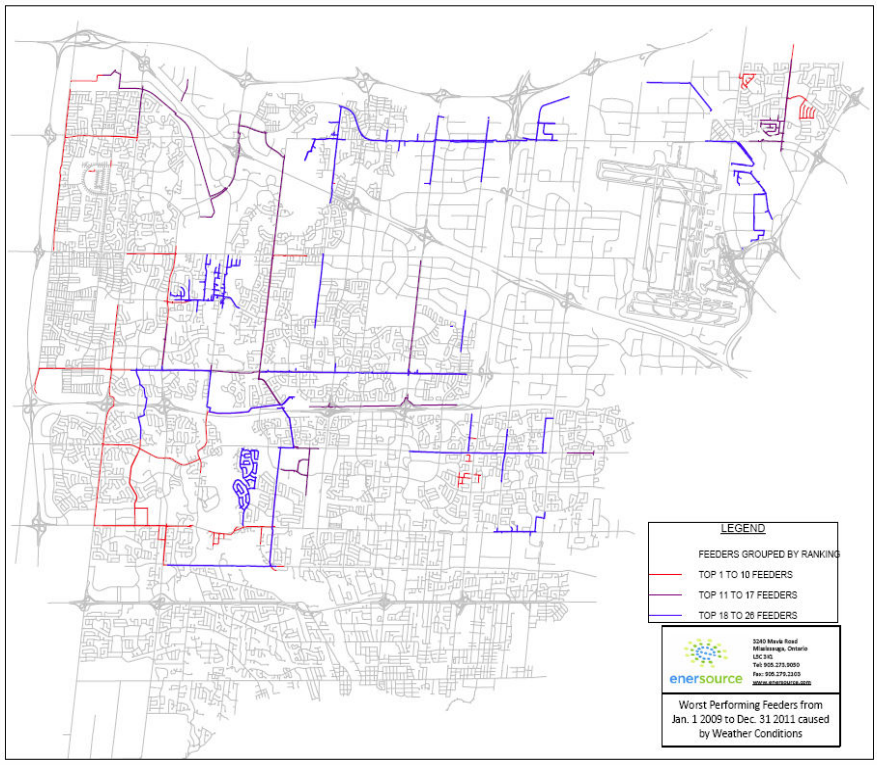


Figure 11.3 – Enersource Worst Feeder Due to Animal Contact (2009-2011)

Feeder failures which are weather related are candidates for future vegetation management and overhead rebuild programs are shown in Figure 11.4 below.

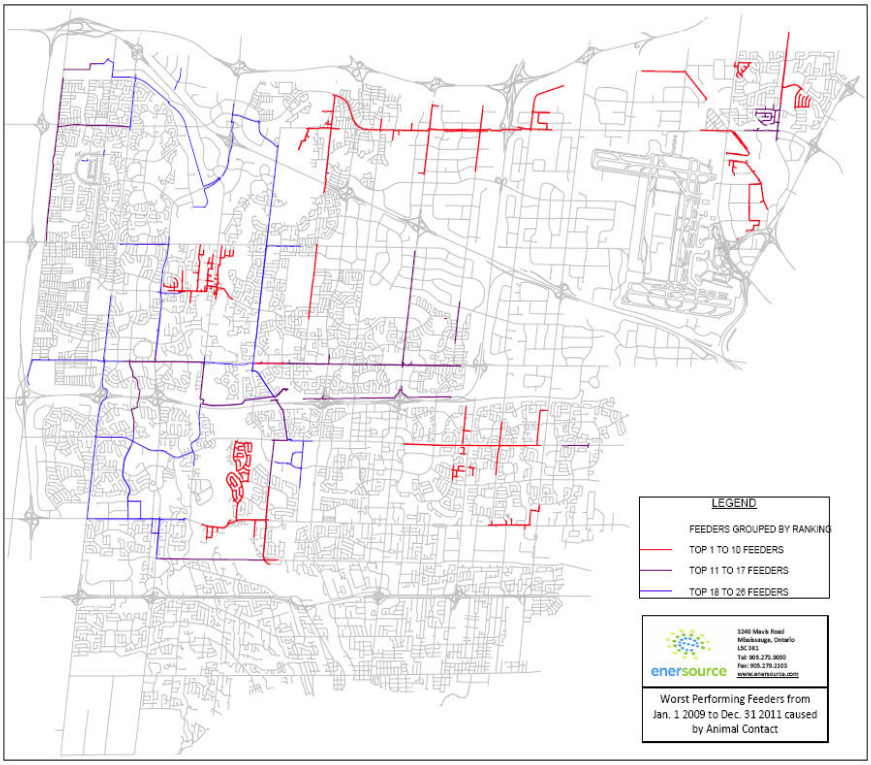


Figure 11.4 – Enersource Worst Feeder Due to Inclement Weather (2009-2011)

INVESTMENT PROGRAM

12. System Capacity – Growth Driven Investment

Growth-driven capital projects ensure the continuation of Enersource's capability to provide a secure and reliable supply of electricity to its customers. Growth is predicted through the combined use of 1) growth projections, 2) historical growth patterns and 3) load forecast models.

This section has two components:

- Subtransmission and Distribution Program
- Municipal Substation Construction and Upgrades Program

For major programs and projects, further details can be found in the appendix of this report.

12.1 Subtransmission and Distribution Program

Projects are designed to increase the capacity of the power system by installing new feeders in response to system load growth forecasts.

In 2010, Enersource delivered almost 8,000 GWh to its customers. Approximately 37% of the power was delivered to large industrial and commercial customers, who account for only 0.2% of the total number of Enersource customers. Individual large customers can add significant load to the system and provide unique challenges to connect and supply. Some customers may need to be connected in areas where there is insufficient capacity, necessitating construction of new feeders or substations to meet their specific needs

12.1.1 Subtransmission and Distribution Program Projects

The following list identifies the major projects that are scheduled for construction in 2012:

<u>44/13.8kV Dundas Street – Glengarry Rd to Mississauga Road</u>

The rebuild of the existing section of the pole line on Dundas Street between Glengarry Road and Mississauga Road is urgent, as the pole line is near the end of its life. In addition to the replacement of the existing circuits, a new 44kV feeder tie will be constructed to add capacity and help with operational requirements, enhance load balancing on the feeders in the area, as well as, improve reliability and system losses. This project requires the replacement of the existing pole line with the installation of new overhead plant with two 8/13.8kV and two 44kV circuits along Dundas Street from Glengarry Road to Mississauga Road.

<u>McNiece MS Feeders – CN Railway Relocations</u>

Completion of this project is necessary to avoid substantial costs associated with rent or purchase of the property along the railroad tracks from CN Railway. This project will allow year round access to the equipment, provide additional backup in the surrounding area and replace near end of life assets. Access has become severely limited due to railway build out. This project will allow

Enersource to fully utilize McNiece MS's assets. This project requires the removal of the existing 16/27.6kV and 2.4/4.16kV overhead lines along railway corridor and installation of underground main feeder circuits on Queen Street West from McNiece MS to Ibar Way.

Revus MS Feeders – CN Railway Relocations

Completion of this project is necessary to avoid substantial costs associated with rent or purchase of the property along the railroad tracks from CN Railway. This project will also allow improved access to the equipment by Enersource personnel, provide additional backup in the surrounding area and replace near end of life assets. Access has become severely limited due to railway build out. Also, this project will provide the necessary connections for the new modular type of 27.6/4.16kV Revus MS. This project requires the removal of the existing 16/27.6kV and 2.4/4.16kV overhead lines installed along the CN Railway tracks. A new pole line on Revus Avenue and Enola Avenue from Revus MS to Lakeshore Road E. will be installed.

The Queensway – Hurontario Street to Camilla Road

This project is necessary to facilitate the rebuild of Melton MS. Also, currently, there are two parallel pole lines along The Queensway between Camilla Road and Hurontario Street that will be converted to a single pole line and connected to the MS. This project will enable future construction of the 2.4/4.16kV ties between Melton MS and Cawthra Road. This enables better utilization of Melton MS, adds capacity to support operational requirements, enhance load balancing on the 2.4/4.16kV feeders in the area, and improves reliability. This project's requires the transfer of the existing 2.4/4.16kV circuits from a difficult to access right-of-way (ROW) to a more accessible 16/27.6kV pole line on The Queensway East. In addition, several termination poles at Melton MS will have to be relocated to facilitate the new connection points at the MS.

Hurontario Street and QEW Overpass

This project is needed to restore the North and South 2.4/4.16kV and 16/27.6kV feeder ties that were removed during the QEW interchange construction. Currently, there are two pole lines on Hurontario Street, one on the north side and one on the south side of QEW. This project will create ties, enable better utilization of Melton MS, enhance load balancing on the 2.4/4.16kV and 16/27.6kV feeders in the area, and improve reliability. This project requires construction of a new pole line link with two 2.4/4.16kV and two 16/27.6kV circuits along Hurontario Street from Premium Way to South Service Road.

Clarkson Rd – Lakeshore Road to Hydro One ROW

This project is required to allow full utilization of Clarkson MS, reduce outages in the area caused by animal and tree contacts and improve operational flexibility, feeder loading and contingency restoration. In addition, the pole line is near the end of its expected life and needs to be rebuilt to prevent any safety hazards that may arise from failure. This project's requires replacement of the existing wood pole line with undersized, #6 copper wire, with a new pole line that will carry two full capacity 2.4/4.16kV circuits constructed from 556 ASC Tree Wire.

Dundas Street – Jaguar Valley to Cawthra Road

The rebuild of the existing pole line on Dundas Street from Jaguar Valley to Cawthra Road is urgent, as the pole line is near the end of life. In addition to the replacement of the existing circuits, two new 44kV feeders will be constructed on the new pole line to add capacity and help with operational requirements, enhance load balancing on the feeders in the area, as well as, improve reliability and system losses. The new pole line will support two new 44kV circuits and two existing circuits, one 8/13.8kV and one 2.4/4.16kV.

The following list shows some of the projects that are proposed for construction in 2013:

44kV Churchill Meadows TS Feeder Egress – along Hydro One Right of Way

This project requires construction of a new pole line on Hydro One ROW, just north of Hwy 403, between Churchill Meadows TS and Winston Churchill Boulevard with four egress 44kV feeders.

Royal Windsor – Winston Churchill to Avonhead Road

This project is a rebuild of the existing overhead pole line on Royal Windsor Drive between Winston Churchill Boulevard and Avonhead Road with the addition of a second 2.4/4.16kV circuit.

Lakeshore Road – Hurontario Street to Cawthra Road

This project is a rebuild of the existing overhead pole line on Lakeshore Road between Hurontario Street and Cawthra Road with the addition of a new 16/27.6kV circuit. The new pole line will have two 2.4/4.16kV and two 16/27.6kV circuits.

Lakeshore Road – Hurontario Street to Kane Road

This project is a rebuild of the existing pole line on Park Street between Hurontario Street and Kane Road with the addition of a new 16/27.6kV circuit. The new pole line will have two 2.4/4.16kV and two 16/27.6kV circuits.

The Queensway – Cawthra Street to Dixie Road

This project requires installation of two new 2.4/4.16kV circuits on the existing concrete pole line on The Queensway East, between Cawthra Road and Stanfield Road. A new pole line between Stanfield Road and Dixie Road will also be built with two 16/27.6kV and two 2.4/4.16kV circuits, which will be tied to the existing circuits on Dixie Road.

Burnhamthorpe Road West – Winston Churchill Boulevard to Ridgeway Drive

This project requires construction of a new pole line with two 8/13.8kV circuits on Burnhamthorpe Road West between Winston Churchill Boulevard and Ridgeway Drive. The new pole line will have two 8/13.8kV circuits.

Subtransmission and Distribution historical and proposed funding from 2006 through 2016 is shown in Table 12.1 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Subtransmission and Distribution	5,358	4,584	8,290	3,515	4,735	4,010	5,832	4,545	4,723	4,901

Table 12.1 – Table of Enersource System Capacity – Subtransmission and Distribution Investment ($'000)

12.2 Municipal Station Construction and Upgrades Program

Substation construction program projects are designed to increase the capacity of the power system by installing new substations and feeders in response to system load growth forecasts.

MS's transform power from 44kV to 8/13.8kV or from 16/27.6kV to 2.4/4.16kV. MS's are capital intensive and make up a major component in the electricity system. Impact from a failure of a major MS can be very significant due to the large number of customers affected. The outage length duration to an MS failure is usually relatively long due to the amount of switching required to supply customers from other nearby stations.

To ensure adequate reliability, all major substation equipment such as power transformers, high and low voltage switchgear is closely monitored by the SCADA system. Yearly oil sample tests are completed to analyze the condition of the MS transformers. This information is one of several factors used to determine if transformers require replacement, service, or additional monitoring.

12.2.1 Municipal Station Construction and Upgrades Program Projects

Every five years Municipal Stations are taken out of service to complete preventative maintenance to sustain and maximize life expectancy of the substation and its vital components. The component replacement program addresses individual assets such as breakers, protection relays, transformers, enclosures, tap changers, switchgear and battery chargers that have reached the end of their service lives and are no longer capable of fulfilling their intended function.
List of major 2012 proposed projects:

<u>Melton MS rebuild</u>

The existing substation is comprised of two transformers and 4 switchgear units with the oldest component being 56 years old. All components have reached end of life with the exception of the 3T2 transformer. The switchgear has deteriorated to the point that operating restrictions have

been implemented to ensure safety for our field personnel. The project includes the addition of an oil containment system, fence upgrade, battery charger system and upgrade to remote terminal equipment. The existing 3T2 transformer is 24 years old and will be inventoried as a system spare.

Erin Mills Town Centre MS

A new substation is being constructed to meet emerging system growth. This new substation is in the Erin Mills area of Mississauga. This new substation will include a new building, one 20 MVA power transformer, one 44kV switchgear and one line up of 8/13.8kV switchgear. The design will have 8 egress feeders into the distribution system servicing the neighborhood. The design will allow for future addition of a second 20 MVA transformer when required.

Kamato MS 8/13.8kV Switchgear Replacement

The 8/13.8kV switchgear at Kamato MS is 24 years old and has deteriorated to the point that safety barriers for field staff needed to be installed in order to operate successfully. Temporary operating instructions have been implemented, however, due to the safety and reliability concern with this particular switchgear. A complete replacement is required to bring the switchgear to a level of safe standard operating procedures. The replacement will include new protection relays and remote terminal equipment.

Avonhead MS Rebuild

The power transformer is 50 years old and from the oil analysis it has reached end of life and needs to be replaced. As part of this rebuild, transformer protection devices will be upgraded to standard circuit breakers.

List of major 2013 proposed projects:

Parkwest MS Rebuild

The existing substation is comprised of a 37 year old transformer and 4 reclosers that have reached end of life. The project will include the addition of an oil containment system, fence upgrade, battery charger system and upgrade of remote terminal equipment.

Revus MS Rebuild

The existing substation is comprised of a 43 year old transformer and 4 reclosers that have reached end of life. The project will include the addition of an oil containment system, fence upgrade, battery charger system and upgrade of remote terminal equipment.

Cawthra MS 2.4/4.16kV Switchgear Replacement

The 2.4/4.16kV English Electric switchgear at Cawthra MS is 55 years old and has reached end of life. The switchgear has deteriorated to the point that safety for field staff is a concern. Temporary operating Instructions have been implemented, however, due to the safety and reliability concern with this particular switchgear, a complete replacement is required to bring the switchgear to a

level of safe standard operating procedures. The replacement will include new protection relays and remote terminal equipment.

Woods MS 8/13.8kV Switchgear Replacement

The 8/13.8kV switchgear at Woods MS is 22 years old and has deteriorated to the point that safety barriers for field staff are needed to be removed in order to operate the equipment successfully. Temporary operating instructions have been implemented, however, due to the safety and reliability concern with this particular equipment, a complete replacement is required to bring the switchgear to a level of safe standard operating procedures. The replacement will include new protection relays and remote terminal equipment.

Matheson MS 8/13.8kV Switchgear Replacement

The 8/13.8kV switchgear at Matheson MS is 22 years old and has deteriorated to the point that safety barriers for field staff are needed to be removed in order to operate successfully. Temporary operating instructions have been implemented, however, due to the safety and reliability concern with this particular equipment, a complete replacement is required to bring the switchgear to a level of safe standard operating procedures. The replacement will include new protection relays and remote terminal equipment.

Substation Construction program historical and proposed funding from 2007 through 2016 is shown in Table 12.2 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Municipal Substation Construction & Upgrades	3,962	5,714	7,500	6,692	5,650	5,302	5,302	5,784	5,784	5,784

Table 12.2 – Table of Enersource System Capacity – Substation Construction Investment ($'000)

Total Growth Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 12.3 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Subtransmission and Distribution	5,358	4,584	8,290	3,515	4,735	4,010	5,832	4,545	4,723	4,901
Municipal Substation Construction & Upgrades	3,962	5,714	7,500	6,692	5,650	5,302	5,302	5,784	5,784	5,784
Total	**9,320**	**10,299**	**15,791**	**10,207**	**10,385**	**9,312**	**11,134**	**10,329**	**10,507**	**10,686**

Table 12.3 – Table of Enersource System Capacity – Growth Driven Investment ($'000)

13. System Sustainment – Reliability Driven Investment

Maintaining reliability is one of the key success factors of Enersource. To maintain reliability Enersource actively tracks outage cause and effects. Based on this information Enersource has ongoing rebuild, upgrade and replacement programs. For major programs and projects, further details can be found in the appendix of this report.

This section has five components:

- Subdivision Rebuilds Program
- Overhead Distribution Sustainment
- Underground Distribution Sustainment
- Transformer Replacement
- Automated Switches / SCADA Program

13.1 Subdivision Rebuild Program

Underground cable failures are the leading cause of equipment failures in the distribution system. To address this risk Enersource plans and executes a cable replacement program. On an annual basis, the worst performing areas of the underground cable system are identified.

Some of the criteria used to identify the worst performing areas include: number of cable failures, age of the cable and cable type installed. Cables older than 35 years are not jacketed and are therefore more susceptible to failure. Typical life expectancy for new replacement underground cable is approximately 40 years.

The actual locations of the yearly rebuild projects are prioritized after the hot summer months when the underground cable system is placed under its most stressful conditions due to high loading. Once the rebuild locations are selected, the projects are included in the following year's capital rebuild plans, budgeted for and designed. To optimize work efficiencies, rebuild projects typically involve the replacement of the complete underground system including cables, transformers, switchgear and other system components that are also near the end of their useful life.

The following criteria are used to identify underground cable replacement projects:

- number of cable failures in the present year
- number of cable failures in the last 2 - 5 years
- number of cable failures in the last 6 - 10 years
- age of the plant
- cable size (main feeder / local distribution) higher priority given to main feeder cables
- system reliability (number of customer's effected and customer minutes)
- existing design (rear lot, no backup, undersized cables)

Figure 13.1 below shows a ten year history of underground cable failures. Each point represents a cable failure. This gives an indication of worst performing distribution areas. Main feeder and distribution cable failures are tracked separately to assist with prioritizing rebuild areas.

Cable failures are then grouped according to distribution feeder layout and street configurations. Typically main feeder cables must be replaced from switchgear to switchgear location in a single rebuild project, whereas local distribution feeders can be installed in project phases. The "oval" rings in Figure 13.1 below represent areas which have been identified as possible rebuild areas.

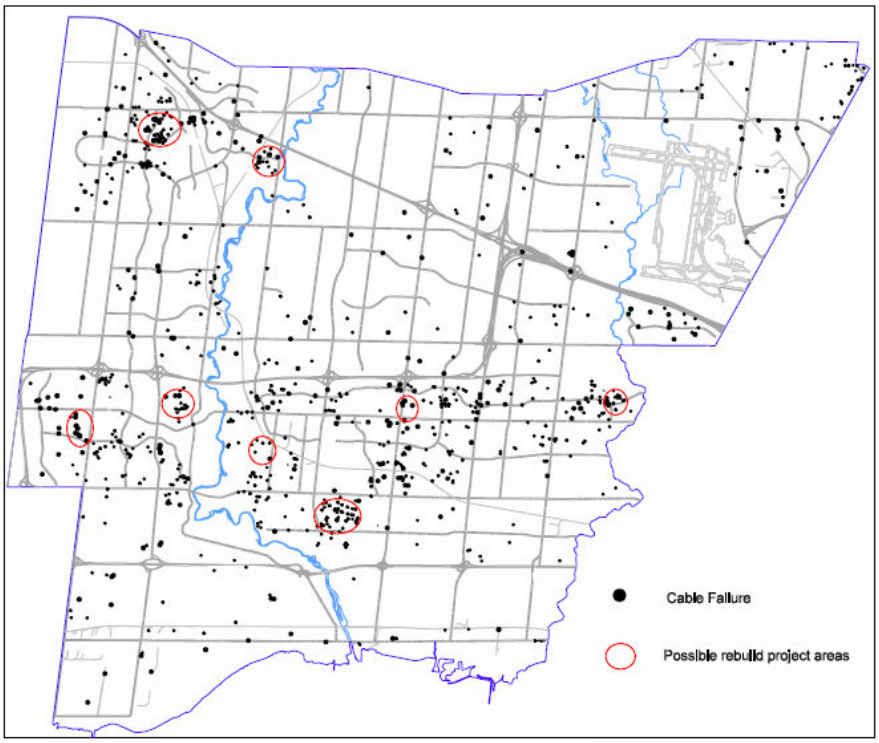


Figure 13.1: Ten year history of underground cable failures

Figure 13.2 below shows a close up pictorial of a segment of Mississauga showing 3 potential rebuild areas. The cable rebuild projects identified by the "oval" ring in this map are:

- Aquitaine and Montevideo Phase 1
- Campobello and Falconer
- Aquitaine and Montevideo Phase 2

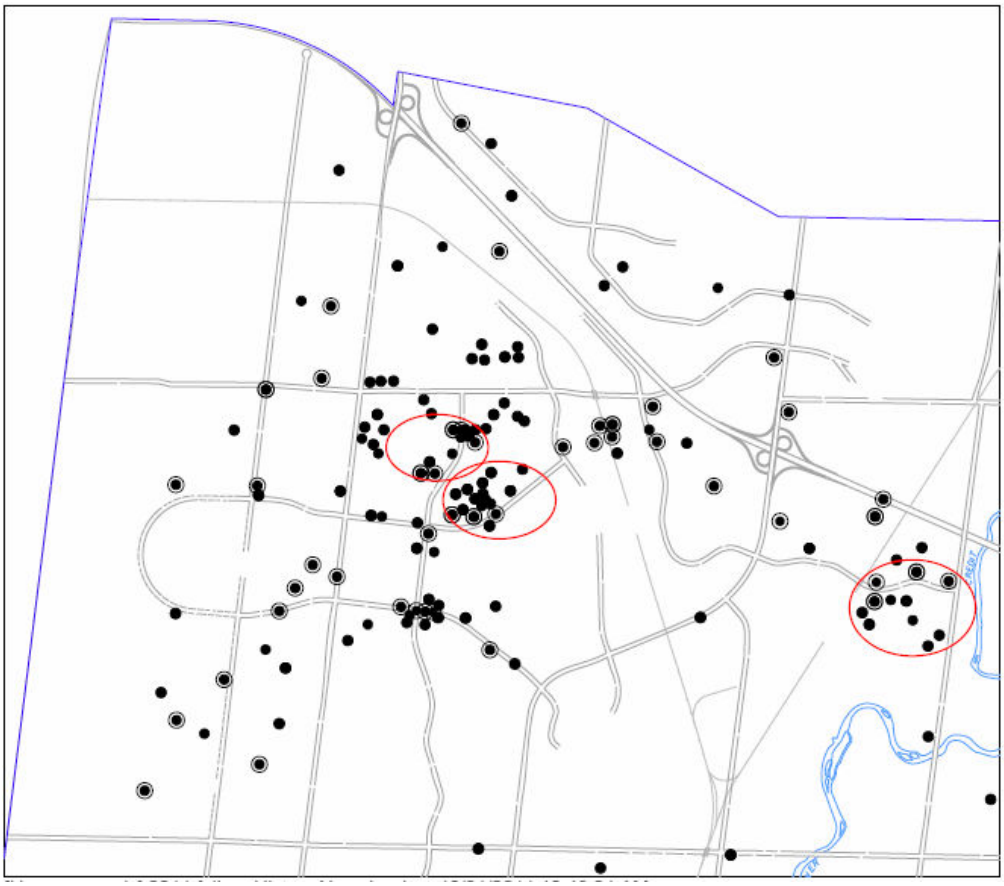


Figure 13.2: History of U/G cable failures in NW District

Table 13.1 below shows a list of underground rebuild projects proposed to be implemented in 2012. These projects have been prioritized based on the selection criteria shown.

Rebuild Areas	LOYALIST	AQUITAINE & MONTEVIDEO PH 1	CAMPOBELLO & FALCONER	ROBERT SPECK	PAISLEY BLVD W & WHALEY DR	AQUITAINE & MONTEVIDEO PH 2	PONYTRAIL & RATHBURN	CULLEN AVE	FARMACOTTAGE	ELENGALE DR
Main feeder Cable	X	X	X	X						
# of faults 2011	3	2	1	1		1			1	
# of faults last 2-5 years	4	2	2	3	1	2	1		3	
# of faults last 6-10 years	1	1		3			2	2		1
Distribution Cable					X	X	X	X	X	X
# of faults 2011		1			6	5	6	1	1	
# of faults last 2-5 years		5	5		4	5	3	9	2	3
# of faults last 6-10 years	1		2		6	3	1	3	5	2
Age of a cable (years)	30	38	33	30	35	35	32	35	32	45
Customers Effected	3700	1100	525	800	650	523	800	1700	1200	725
Customer Minutes	300K	260K	300K	60K	250K	193K	100K	125K	149K	38K
Existing Design	Front Lot	Front Lot	Front Lot	Front lot	Rear Lot	Front Lot	Front Lot	Front Lot	Front Lot	Radial

Table 13.1: Selection Criteria for selecting 2012 UG Rebuild Project

13.1.1 *Subdivision* Rebuild Program Projects

List of identified 2012 projects:

Loyalist Drive Main Feeder Rebuild

The underground cable system along Loyalist Drive is over 30 years old and has had 11 cable failures in the last 6 years, affecting approximately 3,700 customers multiple times for a total of 300,000 customer minutes outage. In addition this area has a natural occurring sulfur material in the ground which is causing the concentric neutral strands of the cable to fail prematurely. The project involves the replacement of 9,000m of 750kcmil cable and 5 switchgears improving the reliability to 3,700 customers.

Aquitaine Avenue and Montevideo Road Phase 1 Rebuild

The underground cable system along Aquitaine Avenue and Montevideo Road is over 38 years old and has had 10 cable failures in the last 4 years, affecting approximately 1,100 customers multiple times for a total of 260,000 customer minutes outage. The project involves the replacement of 2,300m of 750kcmil main feeder, 2,000m of local distribution feeder cables, 3 switchgears and 22 transformers. This project will improve the reliability to 1,100 customers.

Campobello Road and Falconer Drive Main Feeder Rebuild

The underground cable system along Campobello Road and Falconer Drive is over 33 years old and has had 10 cable failures in the last 4 years, affecting approximately 525 customers multiple times for a total of 300,000 customer minutes outage. This project involves the replacement of 4,000m of 350kcmil main feeder cables, 2 switchgears and 25 transformers. This project will improve the system reliability to 525 customers.

Robert Speck Parkway Main Feeder Rebuild

This underground cable system on Robert Speck Parkway is over 30 years old and has had 7 cable failures in the last 7 years, affecting approximately 800 customers multiple times for a total of 60,000 customer minutes outage. The project involves the replacement of 7,500m of 750kcmil cables, improving the reliability to 800 customers.

Paisley Boulevard and Whaley Drive Rebuild

The underground cable system along Paisley Boulevard and Whaley Drive is over 35 years old and has had 11 cable failures in the last 4 years, affecting approximately 650 customers multiple times for a total of 250,000 customer minutes outage. The project involves the replacement of approximately 4,000m existing local distribution feeder cables, 40 transformers and 516 secondary services. This project will improve the reliability to 650 customers.

Aquitaine Avenue and Montevideo Road Phase 2 Rebuild

The underground cable system along Aquitaine Avenue and Montevideo Road is over 35 years old and has had 16 cable failures in the last 6 years, affecting approximately 523 customers multiple times for a total of 193,000 customer minutes outage. The project involves the replacement of approximately 5,000m of existing local distribution feeder cables, 35 transformers and 523 services. This project will improve the reliability to 1,650 customers.

Ponytrail Drive and Rathburn Road Rebuild

The underground cable system along Ponytrail Drive and Rathburn Road is over 32 years old and has had 10 local distribution feeder cables failures in the last 6 years, affecting approximately 800 customers multiple times for a total of 100,000 customer minutes outage. The project involves the replacement of 4,300m of 1/0 cables, 25 transformers and 276 services. This Project will improve the reliability to 800 customers.

Cullen Avenue Rebuild

The underground cable system along Cullen Avenue area is over 35 years old and has had 10 cable failures in the last 6 years, affecting approximately 1,700 customers multiple times for a total of 125,000 customer minutes outage. The project involves the replacement of 2,000m of local distribution feeder cables, 25 transformers and 260 secondary services. This project will improve the reliability to 1,700 Customers.

Farmcottage Court Rebuild

This underground cable system in Farmcottage Court area is over 32 years old and has had 10 local distribution feeder cables failures in the last 6 years, affecting approximately 1,200 customers multiple times for a total of 149,000 customer minutes. The project involves the replacement of 3,000m of 1/0 cables and 40 transformers. This project will improve the reliability of 1,200 customers.

Ellengale Drive Rebuild

This underground cable system along Ellengale Drive is over 45 years old and has had 7 local distribution feeder cables failures in the last 10 years, affecting approximately 725 customers multiple times for a total of 38,000 customer minutes. The project involves the replacement of 1,100m of 1/0 cables, 8 transformers and 92 secondary services. This project will improve the reliability to 725 customers.

Figure 13.3 below identifies the location of proposed 2012 underground cable rebuild projects.

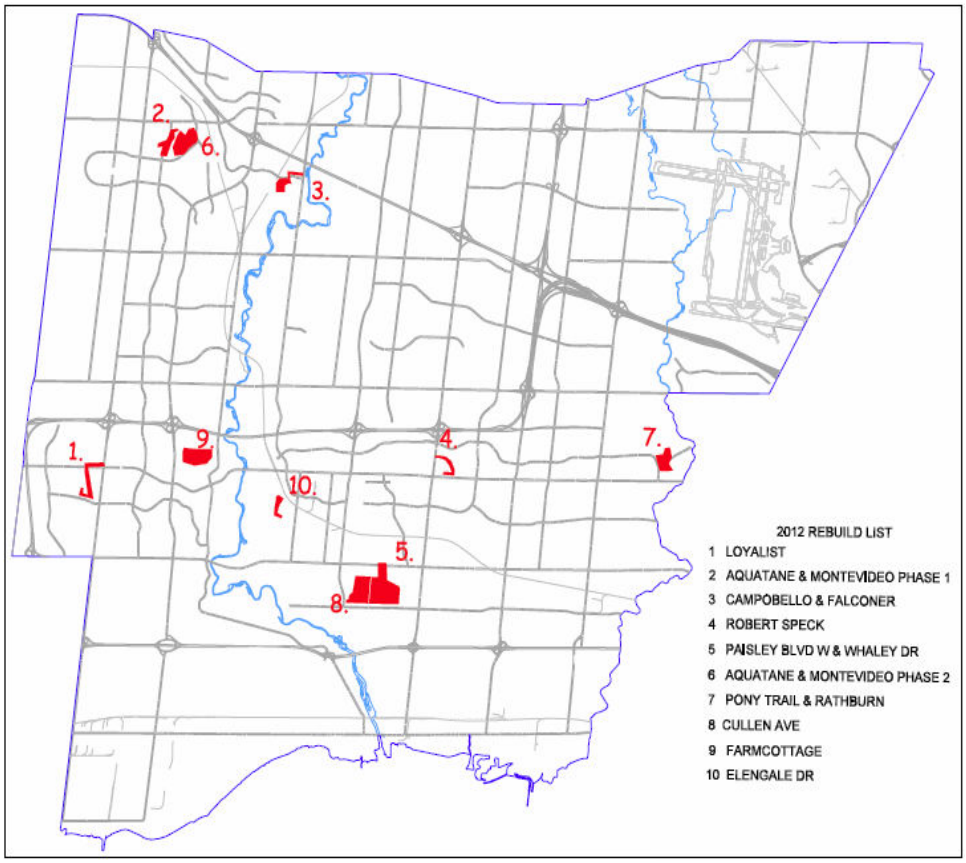


Figure 13.3: Underground Rebuild Project 2012

Sherobee Road Rebuild

In addition to the above projects this rebuild is also required. This project involves replacement of 4 non-standard power transformers, along with the associated accessories and cables. These installations are more than 35 years old. The replacement is also necessary since a recent dissolved gas-in oil analysis of the transformers is well below the acceptable limit. In addition, the units are not a stock item, hence Enersource does not have backup equipment for these installations. If one of the transformers fail, the customers may be subjected to lengthy unscheduled outage, inconvenience and Enersource will likely be required to install temporary generators for an extended period of time until new transformers are purchased and installed.

List of identified 2013 projects:

Mississauga Valley & Bloor St Rebuild

This underground cable system along Mississauga Valley Boulevard and Bloor St is over 38 years old and has had 6 cable failures in the last 5 years, affecting approximately 2250 customers multiple times for a total of 170,000 customer minutes outage. This project involves the replacement of 1,300m of main feeder cable and 3.8km of local distribution cables, 2 switchgears and 40 single phase transformers and 420 secondary services.

Abana Road Rebuild

This underground cable system along Abana Road, Boismere Court, Asta Drive and Pashak Court is over 41 years old. This area has several leaking transformers and few PCB transformers. The project involves the replacement of approximately 2,000m of local distribution feeder cables, 25 single phase transformers and 150 secondary services.

Middlebrook Street Rebuild

This underground cable system along Middlebrook Street, Darcel Avenue and Longo Circle is over 35 years old and has had 11 cable failures in the last 5 years, affecting approximately 8330 customers multiple times for a total of 122,000 customer minutes outage. The project involves the replacement of approximately 4,200m of local distribution feeder cables, 50 single phase transformers and 400 secondary services.

Isabella & Kenbarb Road Rebuild

This underground cable system along Kenbarb Ave, Isabella Street , Mervette Court and Medhat Drive is over 36 years old and has had 7 cable failures in the last 5 years, affecting approximately 500 customers multiple times for a total of 60,000 customer minutes outage. The project involves the replacement of approximately 3,000m of local distribution feeder cables, 20 single phase transformers and 200 secondary services.

Remea Court Rebuild

This underground cable system along Remea Court, Taffy Crescent and Gayline Gardens is over 35 years old and has had 9 cable failures in the last 5 years, affecting approximately 900 customers multiple times for a total of 113,000 customer minutes outage. The project encompasses the replacement of 2,100m of local distribution feeder cables, 20 single phase transformers and 200 secondary services.

Forestwood & Lindenle Rebuild

This underground cable system along Forestwood Drive , Lindenle Drive and Lenester Drive is over 45 years old and has had 7 cable failures in the last 5 years, affecting approximately 780 customers multiple times for a total of 105,000 customer minutes outage. The project involves the

replacement of 5,000m of local distribution feeder cables, 50 single phase transformers and 350 secondary services.

Copenhagen & Fayet Circle Rebuild

This underground cable system along Copenhagen Road and Fayet Circle is over 35 years old and has had 7 cable failures in the last 5 years, affecting approximately 950 customers multiple times for a total of 104,000 customer minutes outage. The project involves the replacement of 3,500m of local distribution feeder cables, 20 pad mounted residential transformers and 350 services.

Subdivision Rebuilds program historical and proposed funding from 2007 through 2016 is shown in Table 13.2 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Subdivision Rebuilds	5,972	7,669	8,354	7,349	6,279	7,356	7,847	8,828	9,808	10,789

Table 13.2 – Table of Enersource System Sustainment – Subdivision Rebuilds Investment ($'000)

13.2 Overhead Distribution Sustainment

Projects under this program deal with the replacement of overhead pole lines that have reached their expected end of life.

13.2.1 Overhead Rebuild Program

The Overhead Rebuild Program is required for maintaining the existing overhead distribution infrastructure and ensuring it is kept at a safe and acceptable performance level.

Pole lines deteriorate over time and their strength may be reduced which introduces a risk of failure, especially under adverse weather conditions. Projects under this program deal with the replacement of overhead pole lines that have reached their expected end of life.

The main components of the overhead system are poles, pole top transformers, switches, conductors and associated overhead hardware such as insulators, fuses and arresters. According to the "Asset Condition Assessment" summarized in Section 8 of this report, the average expected life for wood poles is 45 years and 55 years for concrete poles. The same report also shows the average expected life for overhead transformers to be 45 years. In addition field assessments are carried out by operational personnel while doing work in the area, such as switching and responding to trouble calls in the area. This information along with other data such as system loading, customer outage impact, non-compliance with the current standards, reliability performance and an assessment of the future risks to public safety, allow Enersource to identify locations to be considered for overhead rebuild projects. Overhead rebuild projects include the replacement of poles, primary and secondary conductors, down guys, brackets, cross arms, insulators and transformers, as required.

13.2.2 Overhead Rebuild Program Projects

List of identified 2012 projects:

Old Meadowvale Village Overhead Conversion

Old Meadowvale Village is located in one of the older parts of Mississauga and the only area with a 4.8/8.3kV system in the northern part of the city. This area of 4.8/8.3kV system is a small pocket that is surrounded by 16/27.6kV system. Also this area has long runs of secondary services creating power quality issues to the customers. The existing pole line on Second Line West, Barberry Lane, Old Mill Lane and Pond Street will be rebuilt. The voltage in this area will be converted from 4.8/8.3kV to 16/27.6kV. This project includes the replacement of 56 wood poles, 6 transformers and 200m of primary wires, 2,500m of secondary conductors, 3 in-line switches and transfer approximately 40 existing services. This project is contingent on getting a Herritage Permit from the city.

Lorne Park Estate Rebuild

The existing pole line on Tennyson Avenue, Roper Avenue, Henderson Avenue, Long Fellow Avenue, Sangster Avenue, Chaucer Avenue, McConnell Avenue and Burns Avenue will be rebuilt. This project includes the replacement of 52 wood poles, 9 transformers, 1,200m of primary wires, 3,500m of secondary conductors, 2-in-line switches and transfer approximately 54 existing services. This project is contingent on getting ratepayer co-operation.

Martley Drive Rebuild

The existing pole line on Martley Drive will be rebuilt. This project includes the replacement of 15 wood poles, 2 transformers, 260m of primary wires, 400m of secondary wires and transfer of approximately 25 existing services.

Orchard Road Rebuild

The existing pole line on Orchard Road will be rebuilt. This project includes the replacement of 8 wood poles, 2 transformers, 250m of primary wires, 500m of secondary conductors and transfer of approximately 35 existing services.

Birchwood Drive Rebuild

The existing pole line on Birchwood Drive, Sayers Road and Ravine Drive will be rebuilt. This project includes the replacement of 16 wood poles with concrete poles, 2 transformers, 1,800m of primary wires, 750m of secondary wires and transfer of approximately 20 existing services.

Bremen Lane Rebuild

Bremen Lane is an area with an overhead and underground combination, which is a radial system. This area is selected to provide a backup supply to the area by adding 2 extra phases to the existing 1 phase primary wire. The existing pole line on Bremen Drive, Hammond Road and Morgan Avenue will be rebuilt. This project includes the replacement of 14 wood poles, 2 transformers, 300m of primary wires, 600m of secondary wires and transfer approximately 37 existing services.

A map of overhead rebuild projects proposed for 2012 is provided in Figure 13.4 below:

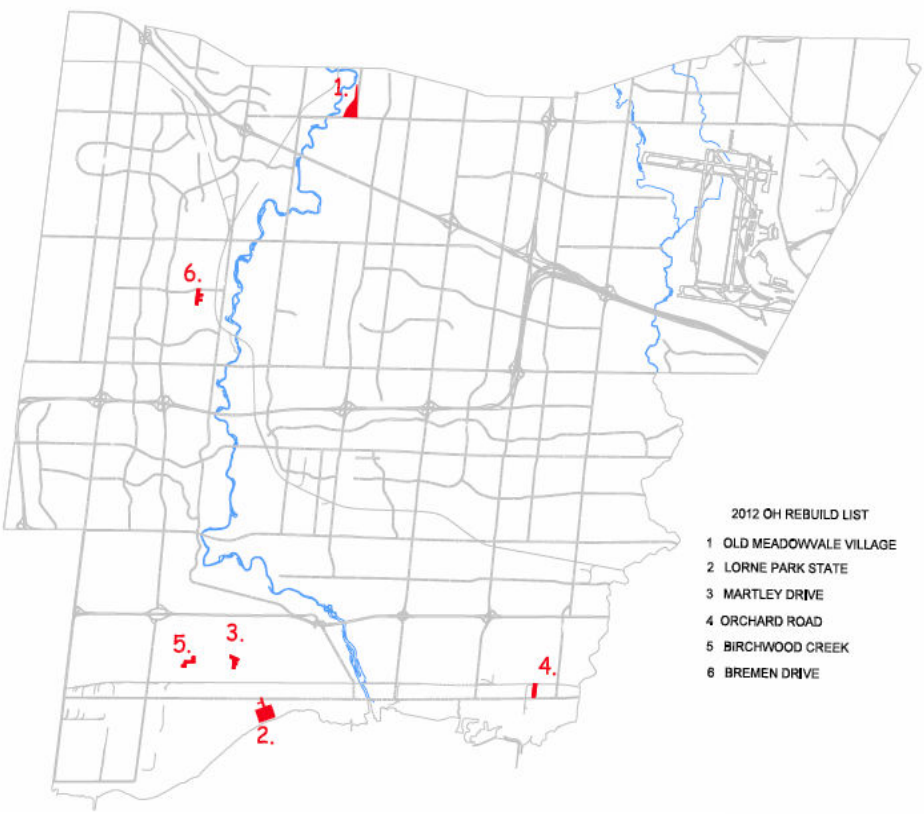


Figure 13.4: Overhead Rebuild Projects 2012

List of identified 2013 projects:

Cortland Crescent

The existing pole line on Courtland Crescent, Harvest Drive, Primate Road and Wealthy Place will be rebuilt. This project includes the replacement of 40 wood poles, 9 single phase transformers 2400m of local distribution wires, 2500m secondary wires and 227 secondary services.

Edenhurst Drive

The existing pole line on Edenhurst Drive, Randi Road and McGill Street will be rebuilt. This project involves the replacement of 36 wood poles, 7 single phase transformers 2800m of local distribution wires, 3000m secondary wires and 132 secondary services.

Birchview Drive

The existing pole line on Birchview Drive and South Aldo Drive will be rebuilt. This project involves the replacement of 32 wood poles, 9 single phase transformers 3350m of mainfeeder wires, 1600m secondary wires and 48 secondary services.

Clarkson Road South

The existing pole line on Clarkson Road South and Sunningdale Bend will be rebuilt. This project involves the replacement of 43 wood poles, 13 single phase transformers 3000m of local distribution wires, 2800m secondary wires and 64 secondary services.

Munden Road

The existing pole line on Munden Road and Pear Tree Road will be rebuilt. This project involves the replacement of 29 wood poles, 5 single phase transformers 800m of local distribution wires, 2200m secondary wires and 85 secondary services.

The Greenway

The existing pole line on The Greenway will be rebuilt. This project involves the replacement of 21 wood poles, 5 single phase transformers 900m of local distribution wires, 2000m secondary wires and 31 secondary services.

13.2.3 Overhead Switch Sustainment Program

Switches are one of the key components of the power system. They are used to reconfigure an electrical circuit by interrupting the current flow, or to isolate conductors. In addition, fused switches are used to protect transformers and underground conductors under fault conditions.

Enersource utilizes four types of overhead switches:

- loadbreak switches (load interrupter)
- remotely controlled switches
- in-line switches
- fused cutouts

In most cases when a failure of an overhead switch occurs, it is caused by contamination of the insulator, which will lead to a flashover and possibly degradation of the insulating medium. Sometimes contamination will cause leakage current to develop across the insulator, or other parts of the switch that are not meant to carry current. As a result, these parts may overheat and cause the switch to fail. Also, the loadbreak switches have mechanisms that suppress the arc when the switch contacts are opening, which sometimes fail, causing arcing and damage to the switch contacts.

In addition, when overhead switches are not operated over a long period of time, the switch contacts seize, preventing the crew from operating the switch.

System impact from a failure of an overhead switch is very significant, as typically they would be installed on the overhead main feeders that may supply multiple municipal stations or subtransmission feeders. Failure of an overhead switch installed near a TS may directly disturb power to several thousand customers, including large commercial and industrial customers.

13.2.4 Overhead Switch Sustainment Program Projects

To ensure that switches on the system are in proper working condition, all switching equipment is inspected with an infrared camera each year for arcing and overheating. If any switches are found faulty, a maintenance crew is dispatched to investigate. Depending on the severity of the defect, they scheduled to either refurbish or replace the switch.

Moreover, every manual loadbreak switch on the 44kV system is proposed to be taken out of service and maintained every five years. Since remotely controlled switches are installed at the critical points on the system where quick isolation of the fault is essential, their maintenance schedule is every three years.

Also under this program, defective cutouts, insulators and porcelain mid-span openers are replaced with polymer insulators or solid blade switches

13.2.5 Pole Replacement Program

Distribution poles serve as support structures for overhead conductors, switches, transformers and other devices. Poles can be wood, concrete, metal or fiberglass. The majority of the poles on the system are wood or concrete.

Wood poles are naturally grown material; therefore all of the poles differ in internal structure and consequently in mechanical strength. Natural degradation of the pole's strength involves naturally occurring fungi that attack and degrade the wood, which results in decay. The severity of the

degradation depends on several factors, such as location, treatment, type of wood and installation practices.

Typically, poles do not fail unless they are exposed to extreme storms, are aged, deteriorated or are damaged in vehicle accidents. Wood poles can also be damaged by woodpeckers, termites or pole fires, which are caused by leakage current from insulator tracking. In addition, to improve appeal, in the past, many wood poles were painted grey. As a result, the paint trapped moisture inside the pole accelerating decay.

Failures of concrete poles may be caused by deterioration of the steel re-bars inside the pole due to an exposure to corrosive chemicals in the soil, or salts used in the winter on the roads. The severity of the degradation depends on several factors such as location, rusting of the exposed re-bars and whether a protective coating was used on the below ground section of the pole.

Since distribution and subtransmission poles support bare overhead wires and other equipment, failure of a pole is very serious, especially since the general public may come in contact with live conductors. In addition, depending on the number of circuits supported by the pole and the voltage, failure may disturb power to thousands of customers.

13.2.6 Pole Replacement Program Projects

In contrast to the overhead rebuild program, this pole replacement program does not target any specific area, but rather poles are replaced individually throughout the city.

Under this program, rather than replacing poles based on their age, location or system improvements, they are replaced based on their condition.

Pole condition is routinely assessed by operational personnel performing work on a pole such as switching or other asset replacement (transformers, insulators, lightning arrestors, etc.). If a deteriorated pole is found, the crew notifies the Control Room of the issue. After further assessment, if necessary, the pole is replaced.

From past experience, it is projected that approximately 50 poles will need to be replaced each year under this program. To support work integration, in addition to the pole itself, the equipment attached to the structure, such as brackets, insulators, transformers, switches, etc. are also reviewed and replaced at the same time if needed.

Overhead Distribution Upgrades program historical and proposed funding from 2007 through 2016 is shown in Table 13.3 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Overhead Distribution Sustainment	3,332	3,531	4,704	3,799	1,676	2,249	2,727	3,058	2,609	2,789

Table 13.3 – Table of Enersource System Sustainment – Overhead Distribution Upgrade Sustainment (in $'000)

13.3 Underground Distribution Sustainment

13.3.1 Pad Mounted Switchgear Replacement Program

The electrical distribution system consists of several important components to deliver electrical service to our customers. Enersource uses padmounted switchgear as an integral component on the underground primary distribution system. These switchgear units serve as an electrical distribution location as well as a switching point. There are approximately 800 switchgear units in the distribution system of which 8% are motorized and monitored via SCADA. The average installed age of these units is 19 years and 22% of the units are older than 25 years.

Air insulated switchgear have increasingly been experiencing failures due to age, design configurations and application voltage levels. This results in power quality, reliability and maintenance issues. These types of faults may expose customers to multiple power interruptions and may take days to troubleshoot and locate the problem. As Enersource's system ages, this type of failure has become even more prevalent.

Several different options were explored to mitigate the deteriorating performance of air insulated switching units. Enersource has selected solid dielectric technology for the padmounted switchgear replacement program. These units have a projected life span of 50 years and will enhance reliability performance as compared to air insulated switchgear.

13.3.2 Pad Mounted Switchgear Replacement Program Projects

Switchgear units which are in the poorest condition and are situated in critical distribution locations are considered for replacement. Enersource installed 7 solid dielectric units in 2011 and will continue to replace approximately 15 units annually starting in year 2012.

13.3.3 Primary Distribution Equipment Replacement Program

In addition to the main system components such as transformers, switchgears, cables, etc. the underground distribution system also consists of smaller, auxiliary components such as elbows, inserts, lightning arresters, fault indicators, etc. Without these auxiliary accessories, the main components of the system become inoperable; therefore, replacement of this equipment before failure is necessary.

Some of the auxiliary system components, such as elbows and inserts, are used by Enersource personnel to perform switching operations, isolations and restoration. Therefore their condition directly influences system reliability as well as the safe operation of equipment.

The useful life for elbows and inserts, which are used in the operation of transformers, varies significantly. Based on past experience, elbows are found to be in poor shape after 20 to 25 years, and need changing along with their inserts.

Other auxiliary devices, such as fault indicators, are used when troubleshooting an outage on the system. Their proper operation influences restoration time and, in turn, overall reliability of the system. Enersource has found through past experience that 20 years for transformer fault indicators is a typical useful life.

In addition, equipment condition is routinely assessed by operations personnel performing work on a transformer or switchgear, such as switching or other asset replacement. If a defective component is found, the crew notifies the Control Room and a maintenance crew is dispatched to perform necessary repairs when required.

13.3.4 Primary Distribution Equipment Replacement Program Projects

Enersource identifies areas that are to be considered for replacement of elbows, inserts, fault indicators and other minor primary distribution equipment. On an annual basis, approximately 40 fault indicators and 100 sets of elbows and inserts are replaced under this project.

13.3.5 Underground Cable and Splice Replacement Program

Underground primary cables are another key component of the distribution power system. They are one of the most expensive components to replace, due to the high costs of materials and high cost of installation.

Typically, underground cable failures are caused by degradation of the insulation, the dielectric medium that insulates the central conductor from the grounded concentric neutral wires. Insulation failure can be caused by several factors, for example:

- contaminated materials during the manufacturing stage
- poor adhesion of the extruded insulation shield
- imperfections at the conductor shield-insulation interface
- water inside the conductor strands or at the concentric neutral wires
- fault currents
- voltage surges from lightning and switching

Failures of underground cables can be as severe as failures of a pad mounted switchgear. The impact on customers depends on whether the cable is a subtransmission cable, main feeder distribution cable or local distribution feeder cable. The subtransmission cables typically supply a Municipal Substation, therefore a failure of a cable supplying a single station may result in a disruption of power for up to 5,000 customers.

The local distribution feeder cable is connected to a pad mounted switchgear or the overhead distribution system and typically will supply up to 500 customers. Cable failure will result in a power outage to all customers connected and typically will momentarily trip the Municipal Station breaker as the fuse isolates the fault.

In addition to cable spot replacement, this project also incorporates heat shrink splice replacement. In the past, several thousands of heat shrink cable splices were installed on the system. Later, it was discovered that a vast majority of them failed prematurely. As a result, Enersource took a proactive approach and decided to replace all known heat shrink splices with new cold shrink splices that perform considerably better. Cable and splice failures remain the largest contributor to customer outage time.

13.3.6 Underground Cable and Splice Replacement Program Projects

This program was developed on the basis of reliability improvements rather than age demographics. Potential projects are identified based on the total number of customer-hours of interruption due to cable or splice failures. These are typically older sections of underground primary cable that have deteriorated over time and where the underground rebuild needs to be delayed. If the same section of cable has had insulation failures three times in a short period of time and no other cables have failed in the same general area then the practice is to replace that section of cable immediately.

13.3.7 Secondary Cable Replacement Program

The distribution system has approximately 193,000 services in the city, the majority of which are connected to a distribution transformer via underground secondary service cable. Based on past experience, secondary cables are less prone to failure compared to primary cables of the same age, which is mainly due to less electrical stress and fewer fault current spikes. However, when secondary cables fail, they need to be immediately repaired, as they are needed to supply customers with power. Every year a number of underground residential and industrial/ commercial services fail beyond reasonable repair and require complete replacement. These failures typically result in outages to single residential or industrial/commercial businesses.

This cable replacement program does not target any specific area, but rather underground secondary cables, over various parts of the city, that have been determined to be at the end of their useful life. They are replaced individually. Under this program, rather than replacing secondary cables based on their age or size, they are replaced based on their condition and number of failures. This program funds the spot replacement of secondary services, over various parts of the city that are at the end of life and are beyond reasonable repair.

13.3.8 Secondary Cable Replacement Program Projects

This project typically covers replacement of approximately 35 secondary services on an annual basis. Aside from this program, secondary service cables are also replaced under the underground cable replacement program.

Underground Distribution Maintenance program historical and proposed funding from 2007 through 2016 is shown in Table 13.4 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Underground Distribution Sustainment	2,280	2,320	2,441	2,133	2,332	2,583	2,998	3,228	3,136	3,228

Table 13.4 – Table of Enersource System Sustainment – Underground Distribution Maintenance Investment (in $'000)

13.4 Transformer Replacement

13.4.1 Pad Mounted Transformer Replacement Program

Distribution transformers are one of the key components of the power system. Their purpose is to lower the primary voltage to secondary voltage levels acceptable to residential, industrial or commercial customers.

Typically transformer failures are random events that occur for various reasons. The most common cause of transformer failure is insulation breakdown. Lightning induced failures are typically manifested by turn-to-turn winding failures at or near the end turns of the windings. Lightning surges are random and may be decreased by the installation of lightning arrestors on the distribution system. Deterioration of insulation is also a function of time and temperature. Transformer temperature, in turn, is related to loading. The thermal stress leads to the ageing and decomposition of both the oil and cellulose used as an insulating material inside the transformer. Once the insulation fails, the transformer windings are short circuited. It is uneconomical to try to repair or refurbish a distribution transformer. Therefore all transformers that fail in the field are automatically replaced by a new unit.

Some of the older single phase pad mount transformers are rusted, especially if they were installed near roads or sidewalks due to salt application in winter time. This will have a negative impact on the transformer and affect performance and operation of the equipment. The transformer will either rust at the back near the tank, eventually causing the cooling oil to leak out or they will rust at the cable compartment. The rusted cable compartment may pose a potential hazard to the general public since it may leave exposed energized parts. As a result, these transformers are replaced immediately.

Every year a number of transformers fail which result in outages to customers. Sometimes transformers are found to be damaged by vehicle accidents or are leaking oil and require changing before they fail. A transformer failure in a residential area may only affect 10 to 12 customers so outage time is minimal. However a transformer failure in an industrial/commercial area could prove costly to the businesses.

Transformers are essential elements of the electrical distribution system and when they fail or if they are unsafe, they must be immediately replaced. To support work integration, in addition to the transformer itself, the equipment attached to it, such as elbows, inserts, fault indicators or arrestors are also replaced at the same time.

13.4.2 Pad Mounted Transformer Replacement Program Projects

The program is needed to allow for the planned and unplanned replacement of underground transformers that are in poor condition or fail in various parts of the city. Transformers are replaced under this program when a failure occurs, or through inspection are identified as damaged, or rusting beyond safe limits.

13.4.3 Pole Mounted Transformer Replacement Program

Similarly to the pad mounted transformers, the main purpose of the overhead transformers is to lower the primary voltage to secondary voltage levels acceptable to residential, industrial or commercial customers. Overhead transformers are not as affected by rust or vehicle accidents since they are not installed as close to traffic as pad mounted transformers.

The overhead transformers are very similar in construction to single phase pad mounted transformers, therefore they mostly fail due to insulation breakdown. When they fail they must be immediately replaced. A transformer failure in a residential area may only affect 10 to 20 customers so outage time is minimal. However a transformer failure for an industrial/commercial customer could prove costly to their business.

Transformer condition is routinely assessed by operational personnel performing work such as switching, responding to trouble calls or outages. The outside crews advise the Control Room of transformers that are in poor condition. When the Control Room gets the information they generate a report and send it to the Overhead Maintenance Department for follow-up. In addition to replacements of transformers that have failed, this program also provides for replacements of transformers that are rusted or leaking.

13.4.4 Pole Mounted Transformer Replacement Program Projects

The program is needed to allow for the planned and unplanned replacement of overhead transformers that are in poor condition in various parts of the city.

Transformer Replacement program historical and proposed funding from 2007 through 2016 is shown in Table 13.5 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Transformer Replacement	686	832	2,464	1,375	947	913	1,004	1,096	1,278	1,461

Table 13.5 – Table of Enersource System Maintenance – Transformer Replacement Investment (in $'000)

13.5 Automated Switches / SCADA Program

The Automated Switches/SCADA needs are identified two ways:

- As a result of inspection programs and tracking the age of Automated Switches and Substation auxiliary components
- As a result of system planning studies and by the monitoring of the worst performing supply points on the electrical grid. New automated switch locations are identified that will increase system performance

The electrical power grid is designed to automatically react to external events to ensure public safety. This could be to instantly shut off power for sustained events (such as a contractor digging

into underground cables) or to have a sub-second momentary outage for tree contact to ensure homes, elevators in buildings and traffic lights are not unnecessarily exposed to long outages.

The Enersource SCADA system (Supervisory Control and Data Acquisition) is a real-time operating system used by the System Control Operator to monitor and control the electrical power grid. The SCADA system has over 15,500 points connected to it that comprises 65 Municipal Substations and over 250 field automated switches.

13.5.1 Automated Switches / SCADA Program Projects

To ensure the continued safe, efficient operation of the electrical grid, remotely controlled overhead and underground switches are used, allowing the System Control Operator to restore power to a large number of customers during outages.

Automated Switches and SCADA program historical and proposed funding from 2007 through 2016 is shown in Table 13.6 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Automated Switches / SCADA Program	1,187	1,438	1,328	1,660	1,473	1,382	1,750	2,119	2,487	2,672

Table 13.6 – Table of Enersource System Maintenance – Auto Switches and SCADA Investment (in $'000)

Reliability Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 13.7 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Subdivision Rebuilds	5,972	7,669	8,354	7,349	6,279	7,356	7,847	8,828	9,808	10,789
Overhead Distribution Sustainment	3,332	3,531	4,704	3,799	1,676	2,249	2,727	3,058	2,609	2,789
Underground Distribution Sustainment	2,280	2,320	2,441	2,133	2,332	2,583	2,998	3,228	3,136	3,228
Transformer Replacement	686	832	2,464	1,375	947	913	1,004	1,096	1,278	1,461
Automated Switches / SCADA Program	1,187	1,438	1,328	1,660	1,473	1,382	1,750	2,119	2,487	2,672
Total	**13,457**	**15,790**	**19,291**	**16,316**	**12,707**	**14,483**	**16,326**	**18,329**	**19,319**	**20,939**

Table 13.7 – Table of Enersource System Maintenance – Reliability-Driven Investment (in $'000)

14. System Expansion and Upgrades – Customer Driven Investment

Customer driven investment projects are required for the connection of new customers or to modify or upgrade a customer's present service. Projects of this nature are not discretionary but mandatory and include work such as new residential connections, industrial/commercial connections and metering equipment upgrades and installation. For major programs and projects, further details can be found in the appendix of this report.

This section has five components:

- Industrial and Commercial Services
- New Subdivisions
- Road Projects
- Metering Equipment
- Smart Metering in New Condos

14.1 Industrial and Commercial Services

New condominium, industrial, commercial and residential subdivision projects are initiated by developers and property owners.

Commercial development is largely influenced by the state of the local economy and commercial vacancy rates. The majority of the commercial development work is occurring in the north-west end. Commercial growth has been slow but steady over the past few years.

Table 14.1 below summarizes historical connection of industrial/commercial customers.

	2007	2008	2009	2010	2011	2012	2013	2014
	Actual					Estimate		
Number of Industrial/ Commercial Services Connected	537	355	397	162	336	250	250	250

Table 14.1 – Table of Enersource New Industrial/Commercial Customer Connections

14.2 New Subdivisions

New subdivision projects are initiated by developers. Enersource connects new subdivision projects to the system as a part of the obligation in Enersource's electricity distribution license and pursuant to the Distribution System Code. Enersource is required to make an "Offer to Connect" to customers on a non-discriminatory basis upon written request for connection. Residential subdivision contributions are determined through the use of the Ontario Energy Board's prescribed economic evaluation methodology. Inputs into the model include projected load characteristics of the subdivision, the value of contributed plant and Enersource's expenditures to service the subdivision.

For new subdivision projects that require expansion of the distribution system, an OEB-approved discounted cash-flow model is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection, expansion and reinforcement.

Enersource tracks proposed developments from information provided by the city's Planning and Building department and uses this information to estimate future loading requirements. The number of concept draft plans and rezoning applications are a good indication of capital expenditures required in future years. Subdivision development is primarily dependent on the local economy. Growth has been steady in this sector over the past few years with townhouses and condominiums dominating the new construction.

Table 14.2 below summarizes historical connection of residential customers.

	2007	2008	2009	2010	2011	2012	2013	2014
	Actual					Forecast		
Number of Residential Services Connected	1,900	3,144	2,900	1,129	2,481	2,450	1,950	3,050

Table 14.2 – Table of Enersource New Residential Customer Connections

14.3 Road Projects

Enersource installs its infrastructure along the right of way that is owned and managed by the city of Mississauga (the "city") and the Region of Peel (the "Region"). Enersource is required to relocate or reconstruct its facilities in order to accommodate the specific requirements of the road authorities in accordance with Public Service Works Highways Act. Road work programs are a significant part of plant relocation throughout the city, impacting both overhead and underground distribution plant.

The amount of relocation work is primarily dependent on the economy and on various levels of government funding. The city establishes a road work program for each year but frequent and sudden changes can occur which adds uncertainty to the forecast of spending for these types of projects. The degree of impact on Enersource is difficult to determine at budget time as road designs are not always available and the impact to Enersource's systems are not determined until detailed design by the road authority is complete. Enersource attempts to better anticipate these possible requests through participation in meetings with the city and the Region and through review of city site plans and zoning amendments. The expected financial impact on Enersource of plant relocation is also based on new approved work projects from the city, historical trends and spending levels, previous year activities and multi year projects.

14.4 Metering Equipment

New metering installations are a requirement to meet the growth of Enersource's customer base. Operation and maintenance of existing metering equipment and back office systems is necessary in order to collect and provide automated meter reading data as the first stage of Enersource's meter to cash process. The reliability and accuracy of the metering equipment and back office systems is paramount to the ongoing billing of all Enersource customers and directly impacts Enersource's revenue stream. New installations are governed by OEB regulation and must be completed within specified timeframes. Equipment must be available in sufficient quantities to allow timely completion of this work. Maintenance of existing metering installations remains a critical function to ensure consistent and complete data for billing on a daily basis and to provide data to the provincial MDM/R.

Incorrect installation or setup and/or lack of maintenance could result in a metering failure resulting in loss of revenue and possible damage to Enersource's reputation.
The Metering Department has several initiatives underway; including:

- the upgrading of existing metering due to customer electrical service upgrades,
- replacing obsolete or damaged meters and
- conversion from 2.5 element to 3 element metering

14.5 Smart Metering in New Condominiums

Enersource continues to expand its efforts in installing individually metered suites ("IMS") with 7,100 units currently being metered. This technology is mainly used in condominiums, but is also applicable for use in metered rental units and apartment buildings through retrofitting. Enersource utilizes Power Line Carrier technology to allow the individual meters to communicate to a transponder which collects the usage data for the suites. This effectively allows the system to utilize the existing electrical wiring in the building as a communication medium thereby saving space and cost. Enersource uses wired phone lines to contact the transponder/collector.

System Expansion and Upgrades – Customer Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 14.3 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Industrial and Commercial Services	5,146	2,182	2,472	260	1,542	1,326	960	960	960	1,143
New Subdivisions	589	1,781	818	8,001	2,398	1,843	1,647	1,647	1,354	1,354
Road Projects	1,075	783	1,056	2,312	991	1,176	1,087	999	999	732
Metering Equipment	(274)	462	408	356	658	952	695	760	859	859
Smart Metering in New Condos	-	1,680	608	970	681	977	952	1,383	865	887
Total	**6,537**	**6,888**	**5,363**	**11,899**	**6,269**	**6,274**	**5,342**	**5,749**	**5,037**	**4,975**

Table 14.3 – Table of Enersource System Expansion and Upgrades – Customer-Driven Investment (in $'000)

15. Non-System Requirements – Regulatory Driven Investment

Regulatory driven investment projects are mandated by industry regulations. Projects of this nature include wholesale metering upgrades per IESO market rules and OEB-sponsored initiatives such as smart metering and time-of-use rates ("TOU") and the Green Energy and Green Economy Act (GEA). For major programs and projects, further details can be found in the appendix of this report.

This section has three components:

- Wholesale Metering
- Smart Metering
- Green Energy and Feed-in Tariffs

15.1 Wholesale Metering

All wholesale metering installations used for settlement in the Ontario electricity wholesale market must be registered with the Independent Electricity System Operator (IESO) and conform to the specifications outlined in the IESO Market Rules. Furthermore, each wholesale metering installation must also comply in accordance to Measurement Canada's (MC) Electricity & Gas Inspection Act. Specifically, all instrument transformers and meters must be approved by Measurement Canada for use. If any of the Instrument Transformers (IT) are not approved by MC, the non-compliant IT must be replaced or approved at the earliest seal expiry date.

Sixteen (16) wholesale metering projects are proposed for 2012 located at Tomken TS, Cooksville TS, Lorne Park TS, Erindale TS and Meadowvale TS. These metering upgrades are required in order to meet the IESO market rules and Measurement Canada regulations. Failure to comply with the IESO Market Rules exposes Enersource to market sanctions, potential fines and increased electrical losses applied against Enersource.

15.2 Smart Metering

Enersource completed its smart meter mass deployment program in 2010, installing approximately 192,000 smart meters in Mississauga. This initiative included the installation of a wireless backhaul comprising of 540 communication devices. The system is now operational, downloading meter data daily and in production with Time of Use Rate billing.

The smart meter deployment included the installation of approximately 174,000 residential and 16,000 small commercial (<50 kW) meters. These meters communicate with a local collector meter, forming individual local area networks ("LAN"), using a proprietary mesh network technology which operates on a 900 MHz wireless system. The mesh network uses 128-bit data encryption to ensure security of the data being transmitted. Enersource has built in operational flexibility with overlapping LAN networks. An advanced metering infrastructure, or AMI, collects data from the collector meters through the wireless backhaul IP network.

System outage reporting at the meter level is planned to be integrated into the outage management system providing more granular information for the control room staff to better determine the

impact of an outage. The existing smart meter infrastructure is expected to provide more data that will enhance Enersource's ability to accurately determine transformer loading and to provide more definitive load forecasting.

Enersource is piloting a remote disconnect meter that eliminates the need for field visits for disconnect/limiter installations in cases of non-payment. The technology allows a meter to be programmed to either act as a limiter or to fully disconnect using a remote command. A reconnect can also be executed using the same communication technology. The existing smart meter infrastructure is expected to provide more data that will enhance Enersource's ability to accurately determine transformer loading and to provide more definitive load forecasting.

In 2012, Enersource received meters for 600V services which were not available in the market during the mass deployment. Approximately 1,500 of these meters will be installed.

15.3 Green Energy and Feed-in Tariffs

Enacted in May 2009, the Green Energy and Green Economy Act ("GEA") was introduced to encourage renewable generation, energy conservation and the creation of green jobs. A key GEA element to enable renewable generation is the Ontario Power Authority's ("OPA") Feed-in Tariff ("FIT").

The FIT program is divided into two streams: large projects above 10 kW follow the FIT process for connection; and smaller projects of 10 kW or less follow the microFIT process for connection. Typically, it is residential customers which apply for microFIT projects whereas business and large industrial customers apply for the FIT projects. The program rules, contracts and prices are developed and set by the OPA.

Enersource has the responsibility to connect renewable generators in accordance to the OPA FIT program rules, OEB codes, Electrical Safety Authority ("ESA") safety requirements and Enersource standards, as outlined in the company's Conditions of Service.

Non-System Requirements – Regulatory Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 15.1 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Conservation & Demand Response	396	(22)	43	-	-	-	-	-	-	-
Wholesale Metering	509	75	974	518	700	2,779	-	-	-	-
Smart Metering	7,374	6,104	8,392	8,184	2,850	1,488	-	-	-	-
Green Energy – FIT/MicroFIT	-	-	-	61	197	133	183	219	256	293
Total	**8,279**	**6,157**	**9,410**	**8,763**	**3,747**	**4,401**	**183**	**219**	**256**	**293**

Table 15.1 – Table of Enersource Non-System Requirements - Regulatory Driven Investment (in $'000)

16. Non-System Requirements – Internally Driven Investment

This section has eight components:

- Engineering and Asset Systems
- Rolling Stock
- Information Technology
- JDE / ERP System
- Meter to Cash
- Grounds & Buildings
- Acquisition of Administration Building
- Major Tools

For major programs and projects, further details can be found in the appendix of this report.

16.1 Engineering and Asset Systems

The Engineering and Asset Systems (E&AS) capital budget provides information technology tools to Enersource personnel, primarily in the Engineering and Operations area, in order to assist them in the management of field assets. These tools include software and hardware for 160 people, including both office and field personnel. The budget assists Enersource in improving efficiency and reliability, reducing costs, and ensuring the safety of staff and the public.

To ensure that all computer hardware is kept current, it is replaced on a three or four year cycle, depending upon the life-span of the equipment. Workstations (high-end PCs used for running Engineering applications), monitors, servers and field computers are replaced on an appropriate schedule to ensure that the equipment complies with current standards. Plotters, or wide-format printers for the output of drawings and maps, have a five to eight year life cycle.

If additional licenses of engineering software applications are required so that information and analysis capability can be made available to more of our internal and field personnel, the E&AS budget is utilized. Software upgrades for any of the Engineering systems are funded through this budget.

The largest two software systems utilized by Engineering and Operations, include the Integrated Operating Model (IOM) and the Automated Mapping/Facilities Management/Geographical Information System (AM/FM/GIS). Any projects related to these two systems are funded through the E&AS capital budget.

Enersource was significantly under budget for 2009 and 2010 because of delays in the IOM implementation, but recovery is anticipated in 2011 and 2012.

16.1.1 Integrated Operating Model

The initial mandate for Enersource's Integrated Operating Model (IOM) project was to integrate AM/FM/GIS, SCADA, and other electronic and manual systems to streamline processes for Operations personnel. The elimination of duplicate record-keeping processes, reduction in manual

paperwork and reporting in the field, and the provision of automatic reporting of reliability indices were planned. The ability to provide a detailed audit trail for improved network analysis and maintenance was a requirement. A greatly improved planning process, rapid response capabilities, and the delivery of greater overall system efficiency were expected results.

Phase 1 of the IOM project has been in use in the System Control Centre (SCC) since September 2008. The system receives regular map updates from AM/FM/GIS and real-time inputs from SCADA. With just a quick glance, operators can track active outages and assess the number of customers affected. Combined with outage probability modeling, this information allows them to determine the most likely source of outages and prioritize restoration efforts. The installation of GPS/mobile routers in company vehicles now allows the operators to determine which crews are able to respond the fastest. Automatic tracking of customer interruption reporting, including the availability of a detailed audit trail, has been in place since July 2010.

The IOM continues to evolve and transform Enersource operational practices and procedures. The IOM has provided the opportunity to formalize and streamline a number of processes while improving the accuracy of its plant and equipment information. Combined with other initiatives, improved capital planning and greater overall system efficiency has been achieved and continued enhancements of the IOM are anticipated.

A project to prioritize and manage SCADA alarms through the IOM is in progress. Eventually, the ability to control SCADA devices from this single IOM interface will also be available. Software for load flow analysis will be integrated into the IOM system so that switch planning can be done with greater ease and confidence. This will allow a large number of redundant paper maps that are currently used to track switch status, to be phased out and replaced over time. Equipment failure tracking will be implemented to more proactively identify grid issues. Integration with the Smart Metering, Interactive Voice Response (IVR), and Customer Care and Billing (CC&B) systems will provide even further ability to track and resolve problems, and communicate with our customers.

Mobile workforce management software (MWFM) is being considered for installation in Enersource trucks. This will allow for more efficient, real-time communication between the crews and the Control Room to take place through the software's computer-aided dispatch modules.

16.1.2 Automated Mapping / Facilities Management / Geographical Information System

The Automated Mapping/Facilities Management/Geographical Information System (AM/FM/GIS) captures both graphical and database information pertaining to Enersource's field equipment. The AM/FM/GIS consists of a map of the city of Mississauga including all streets and lots, with the location of Enersource equipment and civil structures overlaid on the map in the appropriate locations. Also included in the system are relevant non-equipment items such as municipal addresses and easements. In total, Enersource maintains information for 955,000 equipment and other related items.

Employees can quickly and easily locate an equipment item or a customer address on the map and ascertain the overall configuration in the area. Additionally, the maintenance of a database allows for the generation of reports, for example the total number and type of each transformer, pole or other equipment item.

The power source and the downstream devices for each piece of equipment are modeled in the system. This allows for more complex reporting such as the number of customers per feeder. This

model can also be used as the basis for complex engineering analysis software applications such as the one used to calculate line losses.

Since the deployment of the AM/FM/GIS, the number of attributes or characteristics maintained for each equipment item has grown to accommodate a diverse set of user requirements and the system is becoming one of the primary sources of asset information for Enersource. It supplied the base information for the Kinectrics ACA study. Most recently, polychlorinated biphenyl (PCB), infrared, dry ice cleaning, and tree trimming inspection information have been imported into the system. The processes are in place to ensure that the system is updated based on planned rebuilds or new construction projects. Formal processes are being designed and implemented to ensure that emergency field changes and small maintenance jobs are also consistently included in the system.

16.2 Rolling Stock

Enersource requires a fleet of specialized and non-specialized vehicles to complete daily activities including the construction and maintenance of the electrical system. They also provide for quick restoration of power due to electrical system disturbances. Degradation of fleet assets could jeopardize worker safety and negatively affect electrical system performance and response to outages.

To effectively manage fleet assets Enersource has a fleet strategy whose goals are:

- provide safe, reliable and efficient vehicles / equipment to meet the operational needs
- compliance with legislation and regulations
- compliance with accepted industry norms and best practices
- cost effectiveness
- standardization of equipment specifications
- environmental considerations such as fuel economy, exhaust emissions and
- disposal through reputable commercial vehicle and equipment resellers

To achieve the goals outlined above, Enersource maintains a ten year capital plan. This plan is an essential tool for both short and long term budgeting and planning. This plan lists all the current vehicles and proposes the future replacement dates and costs, based on past experience and accepted industry standard vehicle life cycles. Another of the long term goals of the capital plan is to smooth the annual capital expenditures.

Contributing to the proposed replacement date of individual vehicles are factors such as vehicle age, mileage, engine hours, operational cost, maintenance costs and general mechanical condition of the vehicle. Individual assessment of the vehicle is done by Enersource's qualified mechanics when due to be replaced and sometimes adjustments may be made. Some vehicles may be retained because they are in better than average condition and some are replaced earlier due to being in poorer-than-average-condition.

Vehicles are not always replaced "like for like". Prior to replacement of a vehicle, an assessment of the current fleet needs is made with the Supervisors to determine if an alternate vehicle type or size would be beneficial.

The proposed replacement ages for each vehicle class are outlined below. Present replacement criteria are based on manufacturers' recommendations and repair history;

- light vehicles are replaced after 3 - 5 years, or 170,000 km
- service trucks are replaced after 5 - 7 years or 200,000 km
- heavy equipment trucks are replaced after 10 – 12 years, or after 230,000 km and
- work equipment is replaced on a condition based assessment

Additional capital is also required to meet any equipment requirements for staff growth, resulting from succession planning and work program increases.

16.3 Information Technology

The mandate of the Information Technology department is to maintain a highly effective and reliable computer infrastructure, providing services to the organization in areas such as;

- the support, maintenance and security of a corporate network (which includes data, email and web environments) and to provide a highly reliable and available environment
- ensure the availability of all servers supporting the many business critical applications used throughout the company and to provide service and support of these systems as required
- provide efficient, reliable and timely support to the end user community on all desktop and telephone related issues
- management of the corporate telecommunications infrastructure which includes telephones, wireless devices and the Call Center queuing system
- assist in the implementation of new capital and operating projects by providing consulting, planning and implementation expertise in the commissioning of new applications and processes
- administration of all hardware and software maintenance contracts to ensure legal compliance and timely renewals

16.4 JDE / ERP System

Originally implemented in 2003, Oracle J.D. Edwards (JDE) is in the Enterprise Resource Planning (ERP) family of software packages. It is a modular, scalable and integrated information management software system that facilitates the flow of information across the different divisions of Enersource.

The main areas of Enersource that JDE and its auxiliary applications, such as DcLink for processing inventory warehouse transactions wirelessly, assist in processing daily transactions, automate business processes and reporting are:

- Finance – General Ledger, Accounts Payable, Accounts Receivable, Fixed Assets
- Operations – Service Orders, Street-lighting and Supporting Guarantee Calls
- Supply Chain – Inventory/Warehouse Management, Procurement
- Human Resources – Employee Management

JDE also interfaces with other major applications within Enersource such as the Automated Mapping/Facilities Management/Geographical Information System (AM/FM/GIS) and the Customer Care and Billing (CC&B) system to ensure data integrity and simplification of business processes. The capital expenditures required are to leverage our investment to get the most out of

the system so that additional business processes, such project estimating and time entry, can be automated.

In addition, capital funds are required for upgrades so that Enersource remains current on its level and version of software. This will ensure that vendor support and compatibility with other software, such as newer versions Microsoft Office, Internet Explorer and hardware devices such tablets are available. This will aid Enersource to efficiently and promptly adapt as the industry and technology evolves.

16.5 Meter to Cash

The mandate of the Meter to Cash group is to maintain and operate Metering and Customer Information System solutions, in order to provide efficient and accurate meter readings and bills for the residents of Mississauga. The main systems that are used for these processes include Elster AMI, and Oracle's Customer Care and Billing, and Microsoft Biztalk. All systems are modular and scalable for maintainability.

Customer Care and Billing (CC&B) is a fully integrated solution. The main business areas/modules in CC&B are the following:

- customer account management/premise management
- cash and collections
- customer contact tracking and management
- metering / meter management
- meter reading / estimating
- mobile field activity management
- rates engine
- billing / bill creation
- analyses and reporting

CC&B, also interfaces with other major applications within Enersource such as: JD Edwards for general ledger and accounts payable, Field Worker for mobile field activities, and the Metering Application Server (MAS) database, for Time of Use billing, to ensure data integrity and simplification of business processes.

The future capital expenditures are required to leverage Enersource's investment in the various meter to cash systems, and to efficiently comply with the Ontario regulatory changes in the areas of customer service, cash and collection, Meter reading and billing. This will aid Enersource to efficiently and promptly adapt as the industry and technology evolves.

16.6 Grounds and Buildings

Capital expenditures are required to acquire and maintain Enersource workspaces and service facilities to acceptable standards. The existing facility at 3240 Mavis Road presently has approximately 400 employees and this number continues to grow. The Mavis Road facility is comprised of three building sections aging from 20 to 48 years old. To allow for a flexible work area and a safe work environment, it is imperative that Enersource continues its capital expenditures.

Some key projects will see major upgrades in the following areas: HVAC, Electrical panels, Environmental stormceptor installation, roof structures, parking lot paving, windows, health and safety issues as they arise, workstation upgrades and continuing to add infrastructure security systems.

Enersource has a Business Continuity Management site located at 30 Stavebank Road. This building has reached its end of life. A building assessment indicated that over $700K must be invested to bring the facility to acceptable condition. Even with this investment, the facility would still not meet current seismic Ontario Building Code requirements usually attributed to Disaster Recovery Sites. As part of the new Erin Mills Town Centre Municipal Substation construction project, the building will be expanded to accommodate the requirements of the Enersource Business Continuity Management Plan.

16.7 Acquisition of Administration Building

Enersource presently has all of its business functions located at 3240 Mavis Road in Mississauga. This includes all Operations and Administration. Over the past two years, Enersource recognized the need to address the problems created from the lack of office space, lack of meeting room locations, lack of large equipment storage and lack of fleet parking area. To partially address these issues, we have converted trades training areas to meeting rooms, have two employees per office, built workstations wherever space allows. A property has been leased for some of the trucks and materials to reduce fleet parking to accommodate new employee parking.

In 2010, a comprehensive Facility study was completed that identified two conceptual alternatives to the status quo of the 3240 Mavis Road facility. The status quo was not a viable option for the following reasons: inadequate meeting rooms, lack of fleet parking areas, not enough employee parking, cramped quarters, no room for pole storage and lack of space for growth. The proposed alternatives were as follows: construct a building addition to our 3240 Mavis Road facility or acquire/construct a new facility in the North-West area of Mississauga and transfer all Administration function to it.

16.8 Major Tools

In order to maintain and operate an electrical system as well as the operation of a fleet of over 200 vehicles, investment in quality tools is paramount. Each truck is furnished with basic hand tools and equipment while specialized items are limited to specific trucks, (examples include: chainsaws on Forestry vehicles, cable cutters and crimpers on underground vehicles,). Funding for tool expenditures of $5,000 or more per item is classified as a "major tool" and requires additional internal approvals. This category of funds covers the purchase of such items as:

- mud tracks – to allow vehicles to traverse over wet ground and/or over buried pipelines
- ground leads - to allow for the safe operation of personnel and equipment on isolated electrical equipment
- battery operated devices – to allow for repair of underground cable in splice pits and provide better ergonomics for staff
- cable locating equipment – to find buried operational cables so that other utilities can perform their construction work without causing cable damage
- fault finding equipment – to aid in locating underground cable faults requiring repair

Non-System Requirements – Internally Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 16.1 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Engineering & Asset Systems	1,860	1,587	689	349	996	1,145	921	911	687	591
Rolling Stock	1,786	1,542	1,993	1,453	1,900	1,834	1,975	1,975	2,200	2,300
Information Technology	461	952	1,123	2,703	1,199	1,406	886	698	844	750
JDE/ERP System	-	-	-		2,017	1,350	1,547	1,172	1,312	1,312
Meter to Cash (CC&B)	3,276	6,001	2,894	79	891	1,134	726	1,312	1,125	984
Grounds & Buildings	1,033	1,282	1,537	905	1,805	2,476	6,933	4,457	3,268	3,169
Acquisition of Administration Building	-	-	-	-	-	19,952	-	-	-	-
Major Tools	172	240	219	40	243	175	200	200	210	210
Total	**8,588**	**11,603**	**8,456**	**5,530**	**9,052**	**29,472**	**13,187**	**10,725**	**9,646**	**9,317**

Table 16.1 – Table of Enersource Non-System Requirements – Internally Driven Investment (in $'000)

BUDGET SUMMARY

17. Budgets

17.1 System Capacity – Growth Driven Investment

The Growth Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 17.1 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Subtransmission and Distribution	5,358	4,584	8,290	3,515	4,735	4,010	5,832	4,545	4,723	4,901
Municipal Substation Construction & Upgrades	3,962	5,714	7,500	6,692	5,650	5,302	5,302	5,784	5,784	5,784
Total	**9,320**	**10,299**	**15,791**	**10,207**	**10,385**	**9,312**	**11,134**	**10,329**	**10,507**	**10,686**

Table 17.1 – Table of Enersource System Capacity – Growth Driven Investment (in $'000)

Major Variance Factors 2013 Test Year Forecast vs 2012 Bridge Year Forecast

1) Approximate $1.8M increase in growth related investment mainly due to purchase of $2M easement for Churchill Meadows TS egress feeder project. This is the net result of increases in "subtransmission and distribution plus no increase in municipal substation construction and upgrades".

Specifically this funding is for the following item:

- buying the property required to build the egress from the Ontario Realty Corporation (ORC) in the Hydro Right of Way (ROW)

Major Variance Factors 2014 Forecast vs 2013 Test Year Forecast

1) Approximate $0.8M decrease in growth driven investments due to one time easement purchase of $2M in the prior year. This is the net result of decrease in "subtransmission and distribution plus and increase in municipal substation construction and upgrades".

17.2 System Sustainment and Reliability – Reliability Driven Investment

The Reliability Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 17.2 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Subdivision Rebuilds	5,972	7,669	8,354	7,349	6,279	7,356	7,847	8,828	9,808	10,789
Overhead Distribution Sustainment	3,332	3,531	4,704	3,799	1,676	2,249	2,727	3,058	2,609	2,789
Underground Distribution Sustainment	2,280	2,320	2,441	2,133	2,332	2,583	2,998	3,228	3,136	3,228
Transformer Replacement	686	832	2,464	1,375	947	913	1,004	1,096	1,278	1,461
Automated Switches / SCADA Program	1,187	1,438	1,328	1,660	1,473	1,382	1,750	2,119	2,487	2,672
Total	**13,457**	**15,790**	**19,291**	**16,316**	**12,707**	**14,483**	**16,326**	**18,329**	**19,319**	**20,939**

Table 17.2 – Table of Enersource System Maintenance – Reliability Driven Investment (in $'000)

Major Variance Factors 2012 Bridge Year Forecast vs 2011 Actual

1) Approximate $0.7M increase in reliability and growth driven investments. This is the net result of increases in "subdivision rebuilds, overhead distribution sustainment, underground distribution sustainment" less decreases in "transformer replacement, automated switches / SCADA program, subtransmission and distribution and municipal substation construction and upgrades".

Specifically this funding is for the following items:

- to improve reliability by replacing underground equipment
- to ensure that substandard overhead lines, that have reached their end of life are replaced
- to ensure that the replacement of inoperable and end of life equipment
- the spot replacement of overhead switching equipment
- to ensure that substandard wood poles, cross arms and concrete poles are replaced

Major Variance Factors 2013 Test Year Forecast vs 2012 Bridge Year Forecast

1) Approximate $1.8M increase in reliability driven investment mainly due to the higher forecast replacement of distribution system assets. This is the net result of increases in "subdivision rebuilds, overhead distribution sustainment, underground distribution sustainment, transformer replacement, automated switches / SCADA program".

Specifically this funding is for the following items:

- to improve reliability by replacing underground equipment
- to ensure that substandard overhead lines, that have reached their end of life are replaced
- to ensure that the replacement of inoperable and end of life equipment
- the spot replacement of overhead switching equipment
- to ensure that substandard wood poles, cross arms and concrete poles are replaced
- three phase feeders, as well as single phase residential cable replacement

- replacement of sections of the overhead system that have been determined to be at the end of life
- specific projects locations have been identified in the Asset Management Plan

Major Variance Factors 2014 Forecast vs 2013 Test Year Forecast

1) Approximate $2M increase in reliability driven investments due to continued higher forecast replacement of distribution system assets. This is the net result of increases in "subdivision rebuilds, overhead distribution sustainment, underground distribution sustainment, transformer replacement, automated switches / SCADA program".

Specifically this funding is for the following items:

- to improve reliability by replacing underground equipment
- to ensure that substandard overhead lines, that have reached their end of life are replaced
- to ensure that the replacement of inoperable and end of life equipment
- the spot replacement of overhead switching equipment
- to ensure that substandard wood poles, cross arms and concrete poles are replaced
- three phase feeders, as well as single phase residential cable replacement
- replacement of sections of the overhead system that have been determined to be at the end of life

17.3 System Expansion and Upgrades – Customer Driven Investment

The Customer Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 17.3 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Industrial and Commercial Services	5,146	2,182	2,472	260	1,542	1,326	960	960	960	1,143
New Subdivisions	589	1,781	818	8,001	2,398	1,843	1,647	1,647	1,354	1,354
Road Projects	1,075	783	1,056	2,312	991	1,176	1,087	999	999	732
Metering Equipment	(274)	462	408	356	658	952	695	760	859	859
Smart Metering in New Condos	-	1,680	608	970	681	977	952	1,383	865	887
Total	**6,537**	**6,888**	**5,363**	**11,899**	**6,269**	**6,274**	**5,342**	**5,749**	**5,037**	**4,975**

Table 17.3 – Table of Enersource System Expansion and Upgrades – Customer Driven Investment (in $'000)

Major Variance Factors 2013 Test Year Forecast vs 2012 Bridge Year Forecast

1) Approximate $0.9M decrease in customer driven investments due to expected decrease in new customer connection demand. This is the net result of decreases in "industrial commercial services, new subdivisions, road projects, metering equipment, smart metering in new condos".

Specifically this funding is for the following items:

- to meet the demand to connect new industrial/commercial customers
- for existing customer service upgrades

17.4 Non-System Requirements – Regulatory Driven Investment

The Regulatory Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 17.4 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Conservation & Demand Response	396	(22)	43	-	-	-	-	-	-	-
Wholesale Metering	509	75	974	518	700	2,779	-	-	-	-
Smart Metering	7,374	6,104	8,392	8,184	2,850	1,488	-	-	-	-
Green Energy – FIT/MicroFIT	-	-	-	61	197	133	183	219	256	293
Total	**8,279**	**6,157**	**9,410**	**8,763**	**3,747**	**4,401**	**183**	**219**	**256**	**293**

Table 17.4 – Table of Enersource Non-System Requirements - Regulatory Driven Investment (in $'000*)*

Major Variance Factors 2012 Bridge Year Forecast vs 2011 Actual

1) Approximate $2.1M increase in wholesale meter upgrade related to the timing of Hydro One investment.

Specifically this funding is for the following items:

- metering installations must be registered with the IESO and inline with the IESO
- metering installation shall comply in accordance to Measurement Canada's Electricity & Gas Inspection Act
- all instrument transformers and meters must be approved by Measurement Canada

2) Approximate $1.4M decrease in smart metering due to program winding down

Specifically this funding is for the following item:

- for the completion of the Smart Metering deployment for 600 Volt metering installations

Major Variance Factors 2013 Test Year Forecast vs 2012 Bridge Year Forecast

1) Approximate $2.7M decrease in wholesale metering due to expected completion of this program in the prior year.

2) Approximate $1.5M decrease in smart metering due to expected completion of this program in the prior year.

17.5 Non-System Requirements – Internally Driven Investment

The Internally Driven Investment program historical and proposed funding from 2007 through 2016 is shown in Table 17.5 below.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
Engineering & Asset Systems	1,860	1,587	689	349	996	1,145	921	911	687	591
Rolling Stock	1,786	1,542	1,993	1,453	1,900	1,834	1,975	1,975	2,200	2,300
Information Technology	461	952	1,123	2,703	1,199	1,406	886	698	844	750
JDE/ERP System	-	-	-		2,017	1,350	1,547	1,172	1,312	1,312
Meter to Cash (CC&B)	3,276	6,001	2,894	79	891	1,134	726	1,312	1,125	984
Grounds & Buildings	1,033	1,282	1,537	905	1,805	2,476	6,933	4,457	3,268	3,169
Acquisition of Administration Building	-	-	-	-	-	19,952	-	-	-	-
Major Tools	172	240	219	40	243	175	200	200	210	210
Total	**8,588**	**11,603**	**8,456**	**5,530**	**9,052**	**29,472**	**13,187**	**10,725**	**9,646**	**9,317**

Table 17.5 – Table of Enersource Non-System Requirements – Internally Driven Investment (in $'000)

Major Variance Factors 2012 Bridge Year Forecast vs 2011 Actual

1) Approximate $20.4M increase in land, buildings and grounds primarily due to purchase and retrofit of a new building. This is the net result of increases in "engineering & asset systems, information technology, meter to cash, grounds & buildings, new administration building" less decreases in "rolling stock, JDE/ERP system and major tools".

Specifically this funding is for the following items:

- capital expenditures are required to maintain EHM's workspace and service facilities
- building enhancements are required
- professional services was acquired in 2011 to perform planning studies
- a new site was purchased in December 2011 to meet Enersource needs
- expenditures are for the purchase includes existing building, land and interior works
- provide facility improvements by replacement on a priority basis of major building components, such as: windows, doors, fencing, plumbing, security gates, paving, security camera, heating, ventilation and air conditioning (HVAC), garage doors, external wall stucco resurfacing, washroom efficiency programs

Major Variance Factors 2013 Test Year Forecast vs 2012 Bridge Year Forecast

1) Approximate $20M decrease due to new building purchase and retrofit completion in the prior year.

2) Approximate $4.6M increase for improvements to the operations facility and other general equipment.

Specifically this funding is for the following items:

- capital expenditures are required to maintain EHM's workspace and service facilities
- building enhancements are required
- provide facility improvements by replacement on a priority basis of major building components, such as: windows, doors, fencing, plumbing, security gates, paving, security camera, heating, ventilation and air conditioning (HVAC), garage doors, external wall stucco resurfacing, washroom efficiency programs

3) Approximate $0.9M decrease in information systems due to expected completion of major initiatives. This is the net result of increases in "JDE/ERP system" less decreases in "engineering & asset systems, information technology and meter to cash".

Major Variance Factors 2014 Forecast vs 2013 Test Year Forecast

1) Approximate $2M decrease in grounds and buildings investments due to significant completion in the prior year.

17.6 Business Plan: 2012 - 2016

Table 17.6 below summarizes the historical and proposed funding that is required for the next five years to ensure that Enersource has the capability to provide a safe, secure and reliable supply of electricity, meet system load growth demands and successfully complete all regulatory driven initiatives.

Description	Actual					Forecast				
	2007 CGAAP	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS	2015 IFRS	2016 IFRS
System Capacity – Growth Driven Investment	9,320	10,299	15,791	10,207	10,385	9,312	11,134	10,329	10,507	10,686
System Systainment – Reliability Driven Investment	13,457	15,790	19,291	16,316	12,707	14,483	16,326	18,329	19,319	20,939
System Expansion & Upgrades – Customer Driven Investment	6,537	6,888	5,363	11,899	6,269	6,274	5,342	5,749	5,037	4,975
Non-System Requirements - Regulatory Driven Investment	8,279	6,157	9,410	8,763	3,747	4,401	183	219	256	293
Non-System Requirements – Internally-Driven Investment	8,588	11,603	8,456	5,530	9,052	29,472	13,187	10,725	9,646	9,317
TOTAL CAPITAL EXPEDITURES	**46,180**	**50,737**	**58,310**	**52,714**	**42,159**	**63,942**	**46,173**	**45,351**	**44,766**	**46,209**

Table 17.6–Table of Enersource Total Capital Budget Expenditures (in $'000)

17.7 Treatment of Early De-recognition of Assets

Due to International Financial Reporting Standards ("IFRS"), each asset is to be re-recognized when it is disposed or when not future economic benefits are expected from its use. Hence, when an item is de-recognized any gain or loss upon early de-recognition is to be included as a profit of roll. To ensure Enersource complies with IFRS requirements, Enersource has implemented business processes to enable tracking of assets removed from the distribution system.

Tracking of such assets is completed presently with the utilization of automated mapping / facilities management (AM/FM) system which records and stores asset attributes. Alignment of geographic datasets with asset attribute data reflecting Enersource field equipment is completed in the AM/FM system by overlaying a map of Enersource's service territory with locations of Enersource's equipment and civil structures. It is important to note that equipment attributes including asset population are utilized and inputs into the Integrated Operating Model ("IOM") system, the annual asset condition assessment ("ACA") and annual asset management plan activities.

In order to establish the value of the assets removed prematurely from the system, linkages were established between the fixed asset financial system ("JDE") and geographical information system ("GIS") component of the AM/FM system. Reporting tools were developed and implemented to provide frequent status reports which identify changes of plant presently in place in the field for that specific period. Additional future development of systems will enable the capability to record maintenance activities, comprehensive equipment failure data and other relevant transaction history as it applies to each asset class.

In 2011, Enersource incurred a write off of $1.859M which has been coded to depreciation expense and forecasts write offs of $1.924M for 2012, write off of $1.981M for 2013 and write off of $2.041M in 2014.

Asset Management Plan Appendix

Project Business Cases

2012 - 2014

December 19, 2011

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Subtransmission/ Distribution Construction**
BUSINESS UNIT #:	**C0507**
PROJECT NAME:	**2012 - 2 Dundas St – Glengarry Rd to Mississauga Rd**

Project Description

- This project is needed to provide for an additional 44 kV feeder tie on Dundas St from Glengarry Rd to Mississauga Rd, replace the end of life pole line, add capacity to the area, relieve 44 kV conductors in the area and to provide for future load growth.
- The new 44 and 8/13.8 kV overhead circuit will be installed on a pole line that will be rebuilt on Dundas St. that runs from Glengarry Rd across the Credit River to Mississauga Rd.
- This pole line when completed will have two 44 and two 8/13.8 kV circuits on it

Justification

- The major 44kV east & west corridors in the area are on the Ontario Hydro ROW that runs along The Queensway, Dundas St and Burnhamthorpe Rd. This project will complete the 44kV east and west link in this area.
- Additional 44kV capacity is required for the study area based on EHM's planning and design criteria of an average of 300A per main feeder
- This link will be used to provide for better load balancing and contingency across the 44 & 8/13.8kV in this area.
- This circuit will provide for an additional link between the new Churchill Meadows TS and Erindale TS. This is very important in a situation if a transformer is lost at Churchill Meadows TS or Erindale TS. It will allow for load to be picked up by other feeders and provide for contingency.
- This project will also revitalize the existing pole line in this area and bring it to current construction and safety standards.

Alternatives

A number of possible alternatives were analyzed and compared to address this situation. Putting a new pole line across the Credit River on Burnhamthorpe was reviewed but this would have been extremely expensive and have undesirable environmental impacts. The options were limited because there are no other east and west roads to provide overhead links.

The other options involving undergrounding were reviewed and determined to be too costly.

IMPACT OF DEFERRAL

Not proceeding with this project will result in possible overloading of the overhead feeders in the area with an increased risk of interruption to supply and potential hazard of pole line failure due to its poor condition.

Results

- Creation of an additional 44kV feeder tie
- Provide feeder capacity relief, feeder balancing and reduce line losses
- Relieve and balance conductor overloading
- Additional supply capability to increase operating flexibility
- Expansion of 44 & 8/13.8 kV system capability to serve additional load
- Help support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013
Capital Costs funded by Board	$ 446	$ 535
Capital Costs funded by Others		
Total Capital Costs	**$ 446**	**$ 535**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Subtransmission/ Distribution Construction - Overhead**
BUSINESS UNIT #:	**C0507**
PROJECT NAME:	**2012/13 - 8 Dundas St – Jaguar Valley to Cawthra Rd**

Project DESCRIPTION

- This project involves the replacement of the old pole line that only has one circuit of 2.4/4.16 and one circuit of 8/13.8kV on it and provide for two new 44kV circuits.
- This is a continuation of the overhead circuits previously installed on Highway 10, south of Burnhamthorpe Road then east to Jaguar Valley and then south to Dundas St.

The 44kV east and west corridors available between Tomken TS and Erindale TS are limited to Eglinton Ave, the Hydro Right of Way (ROW) located north of Hwy 403, Burnhamthorpe Road, Dundas Street and The Queensway. The last remaining corridor where additional 44kV links can be completed is on Dundas Street and this project will utilize this corridor. During the past summers, the loading on the 44kV overhead lines in the area have exceeded contingency levels. This is based on EHM's planning and design criteria of an average of 300A for main feeders to allow for contingency. The analysis concluded that additional 44kV capacity is required for the area This link will provide backup and contingency between Erindale TS and Tomken TS.

The new pole line will have two 44kV circuits, one 8/13.8 and one 2.4/4.16kV on it. This will ensure that this area has suitable backup in the event of an emergency and will also provide for two important 44kV ties between Tomken TS and Erindale TS. This would be vital if a transformer is lost at either of the TS's since it will allow for contingency, additional backup and switching flexibility.

JUSTIFICATION

- Provides system capacity to allow for future customers
- Provides for load balancing between Erindale TS and Tomken TS transformers and feeders
- Creates additional 44kV feeder ties between TS's for contingency
- Shortens feeder lengths to improve reliability
- Helps support possible GEA initiatives by providing additional electrical infrastructure

ALTERNATIVES

- There is no other alternative to this project because all other 44kV corridors are fully utilized.
- The preferred plan is to replace the existing old pole line. The existing pole line is underutilized and only carries two circuits, one 8/13.8 and one 2.4/4.16kV.

IMPACT OF DEFERRAL

Not proceeding with this project will result in the continued overloading of the 44kV overhead feeders from Tomken and Erindale TS with an increased risk of failure, lack of contingency resulting in possible longer duration interruption to supply.

Results

- Creation of new feeder ties between Tomken TS and Erindale TS for contingency
- Improved pole line appearance and capacity on Dundas Street to current standards
- Provides system capacity to meet existing and new loads in the area
- Provides for load balancing between Erindale TS and Tomken TS transformers and feeders
- Improved switching flexibility
- Provide increased feeder capacity and reduction of line losses
- Increased safety from new infrastructure
- Support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013
Capital Costs funded by Board	$ 535	$ 356
Capital Costs funded by Others		
Total Capital Costs	**$ 535**	**$ 356**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Subtransmission/ Distribution Construction - Overhead**
BUSINESS UNIT #:	**C0507**
PROJECT NAME:	**2013 - 1 Churchill Meadows TS Egress Feeders**

Project Description

- This project is for the installation of a new pole line to be built with four 44 kV circuits from the new Churchill Meadows TS eastward in the Hydro ROW, north of Hwy 403 to Winston Churchill Blvd.
- This also includes buying the property required to build the egress from the Ontario Realty Corporation (ORC) in the Hydro Right of Way (ROW)
- This project compliments the first phase of the 2011, 44 kV Churchill Meadows TS egress project.

Hydro One Networks Inc. (HONI), with co-operation from EHM and several nearby utilities, completed a report in 2006 called the "GTA West Supply Study". This study looked at loading issues and future requirements in the area and as a result there was a need indicated for additional 44 kV capacity in the west side of the City. After careful analysis of alternatives with HONI it was recommended to construct the new 44 kV TS in the Ninth Line and Hwy 403 area to provide load relief, contingency, reliability and to meet the existing and future demand in the surrounding area.

In 2011 an underground egress and pole line with four 44 kV feeders was built westward from the TS to Ninth Line and Eglinton Ave.

This project covers the installation of the feeder egress eastward from the new TS. The new pole line will have four 44 kV circuits and connect to the existing subtransmission feeders at Winston Churchill Blvd just north of Hwy 403.

The completion of the project is subject to the acquisition of property rights from ORC. The completion date is now June, 2012.

Once Churchill Meadows TS is energized with all 8 feeders it will provide transformer and feeder loading relief for both Erindale TS and Meadowvale TS. During summer months, these TS's have periodically run past their Limited Thermal Ratings (10 day LTR).

JUSTIFICATION

- Avoid possible load shedding (rotating blackouts) in the case of a failure of a TS transformer that supplies the load in the western side of the City of Mississauga.
- Provides system capacity to allow for future growth.
- Provides for load balancing on Erindale TS and Meadowvale TS transformers and feeders
- Creates additional 44 kV feeder ties between TS's for contingency.
- Shortens feeder lengths to improve reliability
- Helps support possible GEA initiatives by providing additional electrical infrastructure

ALTERNATIVES

Alternatives were reviewed as part of the HONI GTA West study and this project and its location have been selected as the best alternative.

IMPACT OF DEFERRAL

Not proceeding with this project will result in the continued overloading of the 44 kV feeders and transformers from Meadowvale TS and Erindale TS. Since Churchill Meadows TS is already installed it would leave the new TS capacity stranded.

Results

- Prevents load shedding (rotating blackouts) in the case of a failure of a TS in this area.
- Provides system capacity to meet existing and new loads in the area
- Provides for load balancing on Erindale TS and Meadowvale TS transformers and feeders
- Creates additional 44 kV feeder ties between TS's for contingency
- Improves switching flexibility
- Provide feeder capacity relief and helps to balance feeder loading, reduce line losses
- Shortens feeder lengths to improve reliability
- Support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)		
COST TYPE	**2013**	**2014**
Capital Costs funded by Board	$ 2,891	
Capital Costs funded by Others		
Total Capital Costs	**$ 2,891**	

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Subtransmission/ Distribution Construction**
BUSINESS UNIT #:	**C0507**
PROJECT NAME:	**2013/14 - 3 Lakeshore Rd – Hurontario St to Cawthra Rd**

Project DESCRIPTION

- The project is needed to provide for an additional 16/27.6kV feeder tie between Hurontario St and Cawthra Rd to add capacity, relieve 16/27.6kV conductors in the area and to provide for future load growth.
- The new 16/27.6kV overhead circuit will be installed on a pole line that will be rebuilt. It runs from just east of Hurontario St, along Queen St which then goes south on Seneca St to Lakeshore Rd and then runs east to Cawthra Rd. This pole line when completed will have two 16/27.6 and two 2.4/4.16kV circuits on it.

The Lakeview Water and Waste Water Treatment Plants are located in the vicinity of this work. The addition 16/27.6kV capacity to this area will be utilized to support the additional loading and contingency requirements for these facilities and the surrounding areas. Many new water mains are in construction in the Region of Peel which means loading requirements from these plants will be increasing as additional pumps are added at the plants. The location of the Lakeview Generating Plant and the lands on the south side of Lakeshore Rd near the City of Toronto border are empty and large. These areas may develop in the future and these projects will add capacity to that area. The only 16/27.6 & 2.4/4.16kV east and west corridors from Hurontario St and Cawthra Rd in this area are limited to the above location. This is the only overhead corridor left where an additional 16/27.6kV link can be completed in this area. The review concluded that additional 16/27.6 & 2.4/4.16kV capacity is required for the study area based on EHM's planning and design criteria of an average of 300A per 16/27.6kV feeder. This project will allow for additional contingency in this area. This link may be vital in a situation if a transformer is lost at Cooksville TS since it will allow for load to be picked up from other feeders. This project will also revitalize the existing pole line in this area and bring it to current construction and safety standards.

Justification

- Provides system capacity to allow for future load growth
- Provides for load balancing on 2.4/4.16 & 16/27.6kV MS & TS transformers and feeders
- Creates additional 2.4/4.16 & 16/27.6kV feeder ties between MS's & TS's for contingency, which improves reliability
- Better utilization of Revus MS
- Helps support possible GEA initiatives by providing additional electrical infrastructure

Alternatives

- Possible alternatives were analyzed to address this situation but options were limited because of no other east and west corridors to provide overhead links.
- The other options involving underground were reviewed where determined to be too costly.

The preferred plan is to replace the existing old pole line. The existing pole line is underutilized and only carries three circuits, one 16/27.6 and two 2.4/4.16kV.

IMPACT OF DEFERRAL

Not proceeding with this project will result in lack in contingency, possible overloading of the 16/27.6 & 2.4/4.16kV overhead feeders in the area with an increased risk of lack of contingency and increased interruption to supply.

Results

- Expansion of 16/27.6 & 2.4/4.16kV system supply capability to serve additional load and to increase switching flexibility
- Creation of additional 2.4/4.16 & 16/27.6kV feeder ties for contingency
- Provide feeder balancing and, reduce line losses
- Increased safety from new infrastructure
- Support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)		
COST TYPE	**2013**	**2014**
Capital Costs funded by Board	$ 356	$ 535
Capital Costs funded by Others		
Total Capital Costs	**$ 356**	**$ 535**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Subtransmission/ Distribution Construction**
BUSINESS UNIT #:	**C0507**
PROJECT NAME:	**2013 - 5 Burnhamthorpe Road West – WCB to Ridgeway Dr**

Project DESCRIPTION

- This project involves installation of a new pole line with two 8/13.8 kV circuits from Winston Churchill Blvd westward on Burnhamthorpe Road to Ridgeway Drive

This is a continuation of a larger project which will tie the circuits from Ridgeway MS to the circuits from Desboro MS, provide additional capacity in the area and allow for load to be picked up by multiple sources.

The area between WCB, Hwy 403, Ninth Line and Dundas is supplied by Desboro MS. The main feeder underground cable infrastructure in the area is near the end of its expected life, and in the past few years has caused several large power outages. Installing a new pole line on Burnhamthorpe Road between WCB and Ridgeway Drive will allow for shorter lengths of underground main feeder cables and thus greatly reduces the cost of an underground rebuild project in the area.

Justification

- Create additional 8/13.8 kV feeder ties between Ridgeway MS and Desboro MS for improved outage restoration
- Provide for a better load balancing in the area west of WCB and north of Dundas Rd.
- Increase system capacity in the area to allow for future customers
- Shorten feeder lengths to improve reliability
- Provide feeder capacity relief and help balance feeder loading, and reduce line losses
- Reduce future costs associated with underground main feeder maintenance projects

Alternatives

A number of possible alternatives were analyzed and compared to address this situation. The other options, such as connecting feeders via underground cables, were reviewed and determined to be too costly.

IMPACT OF DEFERRAL

Not proceeding with this project will result in high costs associated with future underground main feeder rebuilds, lack of capacity in the area for future load growth, limited flexibility under contingency situations and voltage drop issues.

Results

- Creates additional 8/13.8 kV feeder ties between Ridgeway MS and Desboro MS
- Provides for better load balancing in the area
- Provides for system capacity to allow for future load growth
- Shortens feeder lengths to improve reliability and reduces line losses
- Provides feeder capacity relief and helps balance feeder loading
- Helps support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2013	2014
Capital Costs funded by Board	$ 668	
Capital Costs funded by Others		
Total Capital Costs	**$ 668**	

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Subtransmission/ Distribution Construction**
BUSINESS UNIT #:	**C0507**
PROJECT NAME:	**2014 - 1 Derry Rd – Hydro ROW to Hurontario St**

Project DESCRIPTION

- This project is needed to provide for additional 16/27.6kV feeder ties on Derry Rd between Hurontario St. and Kennedy Rd to add capacity to the area, relieve 16/27.6kV conductors in the area and to provide for future load growth.
- The 16/27.6kV overhead circuits will be installed on a new pole line that will run on Derry Rd from the Ontario Hydro ROW west to Hurontario St. This pole line when completed will have four 16/27.6kV circuits on it.

The major east & west corridors in the North 16/27.6kV area are in the Ontario Hydro ROW just north of Hwy 403, Eglinton Ave., Britannia Rd and Derry Rd. This project will enhance the 16/27.6kV east and west corridor on Derry Rd. from Bramalea Rd to Mavis Rd which has been in construction for the past 5 years. This is the only overhead corridor left where additional overhead 16/27.6kV links can be completed in this area. The review concluded that additional 16/27.6kV capacity is required for the study area based on EHM's planning and design criteria of an average of 300A for 16/27.6kV feeders and this project will allow for additional contingency in this area. Once the new TS for this area is installed this vital link will be utilized to provide for load balancing across the 16/27.6kV North area. This link will be very important in a situation if a transformer is lost at a 16/27.6kV North TS since it will allow for load to be picked up from other feeders.

The 16/27.6kV North area has severe loading issues in the hot summer months and a new TS will be needed in the next few years. Construction in the 16/27.6kV North still slowly continues and loading keeps increasing. In the meantime new 16/27.6kV ties that connect Erindale and Cardiff TS are needed to alleviate some of the loading issues and to provide for contingency in case a TS fails or a feeder fails. The 16/27.6kV North system has very long feeders because the TS's are very far apart. When a feeder failure across because the feeders are long they affect thousands of customers which dramatically impacts outage time. There are also voltage drop issues because the feeders are so long and contingency issues because the loadings can be very high during the hot summer months. This additional 16/27.6kV capacity to this area will be used to support the additional loading, provide for better load balancing and contingency requirements.

Justification

- Create additional 16/27.6kV feeder ties between Erindale TS and Cardiff TS for contingency
- Provide for load balancing on Erindale TS and Cardiff TS transformers and feeders
- Provide for system capacity to allow for future customers
- Shorten feeder lengths to improve reliability
- Provide feeder capacity relief and help balance feeder loading, reduce line losses
- Help support possible GEA initiatives by providing additional electrical infrastructure

Alternatives

- A number of possible alternatives were analyzed and compared to address this situation. The options were limited because of no other east and west roads to provide overhead links.
- The other options were reviewed and all determined to be too costly.

IMPACT OF DEFERRAL

Not proceeding with this project will result in lack in contingency, voltage drop issues, possible overloading of the 16/27.6kV overhead feeders in the area with an increased risk of lack of contingency and increased interruption to supply.

Results

- Creates additional 16/27.6kV feeder ties between Erindale TS and Cardiff TS for contingency
- Provides for load balancing on Erindale TS and Cardiff TS transformers and feeders
- Provides for system capacity to allow for future customers
- Shortens feeder lengths to improve reliability and reduces line losses
- Provide feeder capacity relief and help balance feeder loading
- Help support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)		
COST TYPE	**2013**	**2014**
Capital Costs funded by Board		$ 891
Capital Costs funded by Others		
Total Capital Costs		**$ 891**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Subtransmission/ Distribution Construction**
BUSINESS UNIT #:	**C0507**
PROJECT NAME:	**2014 - 2 Lakeshore Rd – Hurontario St to Kane Rd**

Project Description

- This project is needed to provide for an additional 16/27.6kV feeder north of Lakeshore Rd on Park St between Hurontario St. and Kane Rd to create a feeder tie between Cooksville TS and Lorne Park TS, add capacity to the area, relieve conductors in the area and to provide for future load growth.
- This will be installed on a pole line that will be rebuilt from the current old pole line that runs from Hurontario St westerly, north of Lakeshore Rd along Park St which then goes to Kane Rd.
- This pole line when completed will have two 16/27.6 and two 2.4/4.16kV circuits on it.

Justification

- The only 16/27.6 & 2.4/4.16kV east and west corridors from Hurontario St westward that tie Lorne Park TS and Cooksville TS are in the Ontario Hydro ROW just north of the QEW which is full and on Park St just north of Lakeshore Rd. This project is the only overhead corridor left where an additional 16/27.6kV link can be completed in this area.
- The review concluded that additional 16/27.6 & 2.4/4.16kV capacity is required for the study area based on EHM's planning and design criteria of an average of 300A per main feeder and this project will allow for additional contingency in this area.
- This link may be vital in a situation if a transformer is lost at Cooksville TS or Lorne Park TS since it will allow for load to be picked up from other feeders.
- This project will also revitalize the existing pole line in this area and bring it to current construction and safety standards.

Alternatives

A number of possible alternatives were analyzed and compared to address this situation. The options were limited because of no other east and west roads to provide overhead links. Lakeshore Rd was considered but the City will not allow overhead construction on that portion of road. The underground options were reviewed and all determined to be too costly.

IMPACT OF DEFERRAL

Not proceeding with this project will result in a lack of TS ties, possible overloading of the 16/27.6 & 2.4/4.16kV overhead feeders in the area with an increased risk of lack of contingency and increased interruption to supply.

Results

- Creation of additional 2.4/4.16 & 16/27.6kV feeder ties
- Additional backup between Cooksville TS and Lorne Park TS
- Provide feeder capacity relief and help balance feeder loading, reduce line losses
- Additional supply capability to increase operating flexibility
- Expansion of 2.4/4.16 & 16/27.6kV system capability to serve additional load
- Helps support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2013	2014
Capital Costs funded by Board		$ 802
Capital Costs funded by Others		
Total Capital Costs		**$ 802**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Substation Construction**
BUSINESS UNIT #:	**C0504**
PROJECT NAME:	**2012 - 4 Erin Mills MS 13.8kV Substation**

Project Description

- The spending for this project is needed to ensure that a new substation is built to provide for the safe, secure and reliable supply of electricity to customers.
- This project is needed to help meet the new load growth in the Erindale west area of the City and to provide contingency for the Credit Valley Hospital and Erin Mills Town Centre Shopping Mall which is a major customer load
- The rear of the new building will also house a backup site for EHM to allow for business continuity in the event of a major disaster or disruption to the head office

Justification

This new Municipal Substations is required to provide for loading capacity in the area which is growing rapidly from Condominium and commercial development along Eglinton Ave near Erin Mills Town Centre Shopping Mall. The MS will also provide for contingency in the area and also provide for important links to heavily loaded nearby MS's in case of major equipment failure. If a MS is lost this can dramatically affect reliability to customers due to the large amounts of customers that would be affected. The outage length due to a MS failure is typically long due to the amount of switching required to be done to pick up customers from other nearby MS's.

Alternate feeders with shorter exposure from the new MS will be used to service the nearby Credit Valley Hospital and the Erin Mills Town Centre Shopping Mall with dedicated feeders.

EHM identified that a backup site was required that would allow for business continuity contingency. This could result from the head office and the Control Room being destroyed from a storm or sabotage or access denied due to a bomb scare. As a part of the MS building construction a backup centre will be included which will allow for an alternate System Control Centre and house other key personnel needed to allow the business to function.

In 2011 this project involved the site plan approval and start of the construction of a new MS building. In addition the major equipment such as transformer, high voltage 44kV breaker, and low voltage switchgear have been ordered. Some progress payments were done in 2011 for the major equipment.

In 2012 the rest of the payment will be made for the major equipment and all other equipment purchases such as battery charger, relays, breakers, tray work transformer station service etc will also be done. All of this equipment will then need to installed and commissioned. All of the associated outside civil work and cable installation will need to be completed and connections and terminations made to the existing electrical distribution system.

Alternatives

This MS is needed in this location to provide for capacity, potential load growth and contingency to the surrounding area. This location was identified in previous master plans by the System Planning department for a MS site and cabling has been routed accordingly.

This MS is required and cannot be permanently removed from service.

Impact of Deferral

If a nearby MS experienced a major equipment failure then this outage would be prolonged to the customers and would dramatically affect reliability due to the large amounts of customers that would be affected. The outage length due to a MS failure would be long due to the large amount of manual switching required and the lack of any automation that could be used to pick up customers from other

nearby MS's. A lengthy outage to Credit Valley Hospital or the Erin Mills Shopping Centre would be damaging.

Not proceeding with this project would result in a decline in reliability due to unplanned outages from failed antiquated components.

Results

- Expansion of system capability to serve additional loads
- Improved system reliability with reduced outage duration and frequency
- Enhanced safety to the public and EHM personnel
- Provide backup to Credit Valley Hospital and to Erin Mills Town Centre Shopping Mall
- Provide for a business continuity site
- Helps support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013
Capital Costs funded by Board	$ 4,049	
Capital Costs funded by Others		
Total Capital Costs	**$ 4,049**	

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Substation Construction**
BUSINESS UNIT #:	**C0504**
PROJECT NAME:	**2013 - 1 Park West Municipal Substation 27.6/4.16kV Upgrades**

Project Description

- The spending for this project is needed to ensure that the end of life municipal station is replaced with a new substation to provide safe, secure and reliable supply of electricity to customers.

Municipal Substations are inspected regularly because they utilize expensive equipment and are a major element in the electrical distribution system. They are composed of individual components that must function as designed in order to maintain acceptable levels of reliability, safety and security. If a MS is lost this can dramatically affect reliability to customers due to the large amounts of customers that would be affected. The outage length due to a MS failure is typically long due to the amount of switching required to be done to pick up customers from other nearby MS's.

EHM currently manages 65 substations with 103 power transformers and their associated high voltage and low voltage switchgear, breakers, reclosures, relays, on load tap changers and battery chargers. 20% of EHM's substations are greater than 40 years old and require replacement. These replacement projects typically involve replacement of HV & LV switchgear, Power transformers, protection relays, SCADA Remote Terminal Unit and upgrading of all associated substation components, to meet current standards and safety practices.

Municipal Substations require refurbishment because equipment and structure lose their capability to safely perform as intended with age. Physical condition of switchgear is also evaluated during regular maintenance inspections. Equipment condition, failure consequence, and failure probability are considered when identifying and prioritizing replacement projects. The power transformer at Park West MS is 36 years old and The switchgear condition/ reliability is in poor condition.

Typically MS's are taken completely out of service on a five year cycle and preventative maintenance is completed to try and prolong the life expectancy of the substation and its vital components. The component replacement program addresses individual assets such as breakers, protection relays, transformers, enclosures, tap changers, switchgear and battery chargers that have reached the end of their service lives and are no longer capable of fulfilling their intended function.

Project spending is prioritized based on the condition of the asset and criteria include reliability, age, safety, availability of parts and improvement in design standards. The new Arc Flash requirements are causing us to re-evaluate view our design criteria and many of the old MS's are found to be lacking. Extra caution is being taken when doing switching at our MS's to ensure safety to personnel and the public is maintained.

Justification

- This project will involve the complete removal of the old MS and replacement with all new up to date equipment.
- This will include the new installation of two 16/27.6kV and two 13.8kV S&C VISTA Switchgear units which are then connected with the IntelliTEAM® automatic restoration system and two three MVA pad mounted transformers with an upgrade of the connected feeders.
- This concept has been used on several the MS's now and is proven to be both economical and efficient.

Alternatives

This MS is needed in its present location to provide for capacity, potential load growth and contingency to the surrounding area and cannot be permanently removed from service.

The MS has reached end of life and it is not economical to refurbish and requires complete

replacement.

Impact of Deferral

If this MS experienced a major equipment failure then this outage would be prolonged to the customers and would dramatically affect reliability due to the large amounts of customers that would be affected. The outage length due to a MS failure would be long due to the large amount of manual switching required and the lack of any automation that could be used to pick up customers from other nearby MS's.

Not proceeding with this project would result in a decline in reliability due to unplanned outages from failed antiquated components.

Results

- Improved system reliability with reduced outage duration and frequency
- Enhanced safety to the public and EHM personnel
- Replacement of end of life assets
- MS will be under Scada control
- Helps support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)		
COST TYPE	**2013**	**2014**
Capital Costs funded by Board	$ 1,157	
Capital Costs funded by Others		
Total Capital Costs	**$ 1,157**	

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Substation Construction**
BUSINESS UNIT #:	**C0504**
PROJECT NAME:	**2013 - 2 Revus Municipal Substation 27.6/4.16kV Upgrades**

Project Description

- The spending for this project is needed to ensure that the end of life municipal station is replaced with a new substation to provide safe, secure and reliable supply of electricity to customers.

Municipal Substations are inspected regularly because they utilize expensive equipment and are a major element in the electrical distribution system. They are composed of individual components that must function as designed in order to maintain acceptable levels of reliability, safety and security. If a MS is lost this can dramatically affect reliability to customers due to the large amounts of customers that would be affected. The outage length due to a MS failure is typically long due to the amount of switching required to be done to pick up customers from other nearby MS's.

EHM currently manages 65 substations with 103 power transformers and their associated high voltage and low voltage switchgear, breakers, reclosures, relays, on load tap changers and battery chargers. 20% of EHM's substations are greater than 40 years old and require replacement. These replacement projects typically involve replacement of HV & LV switchgear, Power transformers, protection relays, SCADA Remote Terminal Unit and upgrading of all associated substation components, to meet current standards and safety practices.

Municipal Substations require refurbishment because equipment and structure lose their capability to safely perform as intended with age. Physical condition of switchgear is also evaluated during regular maintenance inspections. Equipment condition, failure consequence, and failure probability are considered when identifying and prioritizing replacement projects. The power transformer at Revus MS is 42 years old and the switchgear condition/ reliability is in poor condition.

Typically MS's are taken completely out of service on a five year cycle and preventative maintenance is completed to try and prolong the life expectancy of the substation and its vital components. The component replacement program addresses individual assets such as breakers, protection relays, transformers, enclosures, tap changers, switchgear and battery chargers that have reached the end of their service lives and are no longer capable of fulfilling their intended function.

Project spending is prioritized based on the condition of the asset and criteria include reliability, age, safety, availability of parts and improvement in design standards. The new Arc Flash requirements are causing us to re-evaluate view our design criteria and many of the old MS's are found to be lacking. Extra caution is being taken when doing switching at our MS's to ensure safety to personnel and the public is maintained.

Justification

- This project will involve the complete removal of the old MS and replacement with all new up to date equipment.
- This will include the new installation of two 16/27.6kV and two 13.8kV S&C VISTA Switchgear units which are then connected with the IntelliTEAM® automatic restoration system and two 3 MVA pad mounted transformers with an upgrade of the connected feeders.
- This concept has been used on several the MS's now and is proven to be both economical and efficient.

Alternatives

This MS is needed in its present location to provide for capacity, potential load growth and contingency to the surrounding area and cannot be permanently removed from service.
The MS has reached end of life and it is not economical to refurbish and requires complete replacement.

Impact of Deferral

If this MS experienced a major equipment failure then this outage would be prolonged to the customers and would dramatically affect reliability due to the large amounts of customers that would be affected. The outage length due to a MS failure would be long due to the large amount of manual switching required and the lack of any automation that could be used to pick up customers from other nearby MS's.

Not proceeding with this project would result in a decline in reliability due to unplanned outages from failed antiquated components.

Results

- Improved system reliability with reduced outage duration and frequency
- Enhanced safety to the public and EHM personnel
- Replacement of end of life assets
- MS will be under Scada control
- Helps support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2013	2014
Capital Costs funded by Board	$ 964	
Capital Costs funded by Others		
Total Capital Costs	**$ 964**	

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Substation Construction**
BUSINESS UNIT #:	**C0504**
PROJECT NAME:	**2013/14 - 6 Rubin Municipal Substation Upgrade**

Project Description

- The spending for this project is needed to meet the new load growth in the Tomken TS area of the City so that a secure and reliable supply of electricity is provided to customers.

Investment Summary:

Municipal Substations are a major element in the system and are composed of individual components that must function as designed in order to maintain an acceptable level of reliability, safety and security.

This Municipal Substations is required to provide for more capacity in the growing area of the Airport Corporate Centre. We presently have a temporary substation that will not be capable of delivering the planned capacity past 2014. This temporary substation with a high fence, barb wire is not conducive to the general upscale area. A completely new substation with a standard building will be designed to double the capacity and will offer a less exposed station to storms. The MS will also provide for greater contingency in the area and also provide for important links to heavily loaded nearby MS's in case of major equipment failure. If an MS is lost this can dramatically affect reliability to customers due to the large amounts of customers that would be affected. The outage length due to a MS failure is typically long due to the amount of switching required to be done to pick up customers from other nearby MS's. The existing 24 year old 20 MVA power transformer is in good condition with the existing 44kV Switchgear will be re-utilized in the new design to reduce costs.

This project will involve the construction of a new building, purchase of a new 20 MVA Power transformer, new 13.8 kV switchgear with GE F60 microprocessor based relays, new 44kV switchgear and associated cables and duct banks to connect to the power grid.

Impact of Deferral

If this MS experience a major outage this would dramatically affect reliability due to the large amounts of customers that would be affected. The outage length due to a MS failure would be length due to the large amount of switching required and the lack of any automation that could be done to pick up customers from other nearby MS's.

Not proceeding with this project would result in a decline in reliability due to unplanned outages from failed antiquated components.

Results

- Ensure adequate capacity to reliably supply customers in the Tomken 8/13.8kV area
- Expansion of system capability to serve additional loads
- Improved system reliability with reduced outage duration and frequency
- Replace end of life assets

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2013	2014
Capital Costs funded by Board	$ 1,157	$ 2,217
Capital Costs funded by Others		
Total Capital Costs	**$ 1,157**	**$ 2,217**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Capacity - Growth Driven Investments**
INVESTMENT NAME:	**Substation Construction**
BUSINESS UNIT #:	**C0504**
PROJECT NAME:	**2014 - 3 Park Royal Municipal Substation 27.6/4.16kV Upgrades**

Project Description

- The spending for this project is needed to ensure that the end of life municipal station is replaced with a new substation to provide safe, secure and reliable supply of electricity to customers.

Municipal Substations are inspected regularly because they utilize expensive equipment and are a major element in the electrical distribution system. They are composed of individual components that must function as designed in order to maintain acceptable levels of reliability, safety and security. If a MS is lost this can dramatically affect reliability to customers due to the large amounts of customers that would be affected. The outage length due to a MS failure is typically long due to the amount of switching required to be done to pick up customers from other nearby MS's.

EHM currently manages 65 substations with 103 power transformers and their associated high voltage and low voltage switchgear, breakers, reclosures, relays, on load tap changers and battery chargers. 20% of EHM's substations are greater than 40 years old and require replacement. These replacement projects typically involve replacement of HV & LV switchgear, Power transformers, protection relays, SCADA Remote Terminal Unit and upgrading of all associated substation components, to meet current standards and safety practices.

Municipal Substations require refurbishment because equipment and structure lose their capability to safely perform as intended with age. Physical condition of switchgear is also evaluated during regular maintenance inspections. Equipment condition, failure consequence, and failure probability are considered when identifying and prioritizing replacement projects. The power transformers at Park Royal MS are 43 and 49 years old and the 4 kV switchgear is 43 years old with a poor condition.

Typically MS's are taken completely out of service on a five year cycle and preventative maintenance is completed to try and prolong the life expectancy of the substation and its vital components. The component replacement program addresses individual assets such as breakers, protection relays, transformers, enclosures, tap changers, switchgear and battery chargers that have reached the end of their service lives and are no longer capable of fulfilling their intended function.

Project spending is prioritized based on the condition of the asset and criteria include reliability, age, safety, availability of parts and improvement in design standards. The new Arc Flash requirements are causing us to re-evaluate view our design criteria and many of the old MS's are found to be lacking. Extra caution is being taken when doing switching at our MS's to ensure safety to personnel and the public is maintained.

Justification

- This project will involve the complete removal of the old MS and replacement with all new up to date equipment.
- This will include the new installation of two 16/27.6kV and two 13.8kV S&C VISTA Switchgear units which are then connected with the IntelliTEAM® automatic restoration system and two three MVA pad mounted transformers with an upgrade of the connected feeders.
- This concept has been used on several the MS's now and is proven to be both economical and efficient.

Alternatives

This MS is needed in its present location to provide for capacity, potential load growth and contingency to the surrounding area and cannot be permanently removed from service.

The MS has reached end of life and it is not economical to refurbish and requires complete replacement.

Impact of Deferral

If this MS experienced a major equipment failure then this outage would be prolonged to the customers and would dramatically affect reliability due to the large amounts of customers that would be affected. The outage length due to a MS failure would be long due to the large amount of manual switching required and the lack of any automation that could be used to pick up customers from other nearby MS's.

Not proceeding with this project would result in a decline in reliability due to unplanned outages from failed antiquated components.

Results

- Improved system reliability with reduced outage duration and frequency
- Enhanced safety to the public and EHM personnel
- Replacement of end of life assets
- MS will be under Scada control
- Helps support possible GEA initiatives by providing additional electrical infrastructure

Estimated Annual Expenditure ($ 1,000's)		
COST TYPE	**2013**	**2014**
Capital Costs funded by Board		$ 1,350
Capital Costs funded by Others		
Total Capital Costs		**$ 1,350**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Subdivision Rebuilds**
BUSINESS UNIT #:	**C0505**
PROJECT NAME:	**2012/13/14 – Subdivision Rebuilds**

Project Description

- Spending for these projects is required to improve reliability by replacing underground equipment that has experienced several outages and has reached end of life.

EHM has obligations as a public utility to deliver and to maintain reliable electrical energy with minimal service interruptions to its customers. Therefore the system must be kept reliable, robust and well maintained to perform as designed under all normal conditions. The artery used to deliver power to the system is the underground cable. Underground cable and splice failures are the leading cause of outages on the distribution system. The following projects have been selected for rebuilds in the near future:

- Loyalist Main Feeder Rebuild
  The project includes the replacement of 9.0km of main feeder cable and 5 switchgears.
- Aquitaine and Montevideo Phase 1 Rebuild
  Under this project 2.3km of main feeder cable and 2km of local distribution feeder cables, 3 switchgears and 22 mini-pad transformers will be replaced.
- Campobello and Falconer Main Feeder Rebuild
  This project involves the replacement of 4km of main feeder cables, 2 switchgears and 25 single phase transformers.
- Robert Speck Main Feeder Rebuild
  The project covers the replacement of 7.5km of main feeder cables.
- Paisley Boulevard and Whaley Drive Rebuild
  The project involves the replacement of approximately 4.0km of local distribution feeder cables, 40 units single phase transformers and 516 secondary services.
- Aquitaine and Montevideo Phase 2 Rebuild
  The project includes the replacement of approximately 5.0km local distribution feeder cables, 35 mini-pad transformers and 523 services.
- Sherobee Road Apartments Rebuild
  Under this project four power transformers, associated accessories and distribution cables supplying apartments at 2170 and 2100 Sherobee Road will be replaced.
- Farmcottage Court Rebuild
  Under this project 3.0km of local distribution feeder cables and 40 pad mounted transformers will be replaced.
- Ponytrail and Rathburn Rebuild
  The project involves the replacement of 4.3km of local distribution feeder cables, 25 pad mounted residential transformers and 276 services.
- Cullen Avenue Rebuild
  The project encompasses the replacement of 2.0km of local distribution feeder cables, 25 single phase transformers and 260 secondary services.
- Ellengale Drive Rebuild
  The project covers the replacement of 1.1km local distribution feeder cables, 8 single phase transformers and 92 secondary services.
- Mississauga Valley and Bloor Street Rebuild
  This project involves the replacement of 1.3km of main feeder cable and 3.8m of local distribution cables, 2 switchgears and 40 single phase transformers and 420 secondary services.

- Abana Road Rebuild
  The project involves the replacement of approximately 2.0km of local distribution feeder cables, 25 single phase transformers and 150 secondary services.
- Middlebrook Street Rebuild
  The project involves the replacement of approximately 4.2km of local distribution feeder cables, 50 single phase transformers and 400 secondary services.
- Isabella and Kenbarb Road Rebuild
  The project involves the replacement of approximately 3.0km of local distribution feeder cables, 20 single phase transformers and 200 secondary services.
- Remea Court Rebuild
  The project encompasses the replacement of 2.1km of local distribution feeder cables, 20 single phase transformers and 200 secondary services.
- Forestwood and Lindenle Rebuild
  The project encompasses the replacement of 5.0km of local distribution feeder cables, 50 single phase transformers and 350 secondary services.
- Copenhagen and Fayet Circle Rebuild
  The project involves the replacement of 3.5km of local distribution feeder cables, 20 pad mounted residential transformers and 350 services.
- City Centre Phase 3 Rebuild
  The project includes the replacement of approximately 1.4km main feeder cable and 2 switch gears.
- Lara Woods Rebuild
  The project covers the replacement of 4.5km local distribution feeder cables, 38 single phase transformers and 460 secondary services.
- Windjammer Road Rebuild
  The project involves the replacement of 3.2km of local distribution feeder cables, 40 pad mounted residential transformers and 550 services.
- Tea Garden Circle Rebuild
  The project involves the replacement of 5.5km of local distribution feeder cables, 60 pad mounted residential transformers and 660 services.
- Constable Road Rebuild
  The project involves the replacement of 3.6km of local distribution feeder cables, 50 pad mounted residential transformers and 550 services.

Justification

The typical life expectancy for underground cable is approximately 40 years. Cables installed prior to 1980 will likely not last as long as the more modern cables because they were usually not jacketed, installed directly in the ground and not as well manufactured and are ultimately more susceptible to failures.

Many of the failures in cables occur for one or more of the following reasons:

- Age of the cable
- Insulation deterioration resulting from long term exposure to high temperatures due to sustained loading
- Moisture penetration
- Physical damage from contractor digging into cables
- Poor installation methods used by contractors
- Exposure to high currents during cable faults and from system loading

Each year after the hot summer peak, the equipment failure rates are reviewed by the Reliability Department and this information is used to determine the areas to rebuild. Potential projects are identified mainly on the basis of reliability data and age demographics.

As a part of the program, EHM usually replaces not just primary cables but also transformers, switchgears, elbows, inserts, arrestors and secondary cables to ensure that the area is fully rehabilitated. Replacing underground residential plant is very costly due to high construction and material costs. These costs are high because of having to replace equipment in an existing, congested, narrow boulevard that is full of other

utilities and digging can be very difficult. Trees on the boulevard require special care so that they are not damaged and homeowners expect the site to be left liveable at the end of each today to minimize customer complaints. Sometimes large neighbourhoods require replacement and these jobs are broken out into smaller and more manageable phases. Civil work includes installation of new equipment including ducts to install the cables in, installation of primary and secondary cables, transformers, foundations and the restoration of the existing grass boulevards, sidewalks, roads and driveways. All civil construction is tendered out to ensure that work is completed at the lowest possible cost.

Alternatives

Cable replacement can be temporarily deferred depending on the number of customers that could be affected by the cable failing but ultimately the cables will need replacement at some point.

Sometimes replacement is delayed if the area is destined for a rebuild by other utilities doing the same type of work or if the City of Mississauga or Region of Peel is planning to replace street lighting or do road work so that impact to the customer is minimized.

Impact of Deferral

There would be an increase in the risk of equipment failure under adverse conditions, leading to reduced reliability and safety hazards to the public and EHM personnel.

Results

- Reduced likelihood of customer outages
- Reduced outage duration and frequency of interruptions to customers
- Replaced end of life assets

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 7,356	$ 7,847	$ 8,828
Capital Costs funded by Others			
Total Capital Costs	**$ 7,356**	**$ 7,847**	**$ 8,828**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Overhead Distribution Upgrades**
BUSINESS UNIT #:	**C0561**
PROJECT NAME:	**2012/13/14 – 1 Overhead Rebuilds**

Project Description

- This program is needed to ensure that substandard overhead lines, mainly in older residential areas that have reached their end of life are replaced on an annual basis.
- Three phase feeders, as well as single phase residential distribution feeders are predominantly in the older, south end of the City. These circuits are prone to failure due to age and exposure to the elements.
- This program funds the replacement of sections of the overhead system over various parts of the City that have been determined to be at the end of life.

Pole lines deteriorate over time and when their strength is reduced to the point that there is a risk of failure under adverse weather conditions then they are deemed to be at end of life. Some of the pole lines are single phase primary lines with no backup making restoration for these customers longer. Other pole lines support three phase primary lines that act as backup to other circuits enabling good reliability and faster restoration for customers. The safe, reliable operation of the distribution system depends on the condition of the overhead assets.

Pole line condition is routinely assessed by operational personnel performing work in the area such as switching or other asset replacement (transformers, insulators, lightning arrestors, etc.) or from responding to power outages. The outside crews advise the Overhead Maintenance Supervisor directly or the Control Room of pole lines that are in poor condition. If the Control Room gets the information they generate a report and sent it to the Overhead Maintenance Supervisor for follow-up. Outside employees who are on light duty from injury are also sometimes given sections of the City to visually inspect the condition of the existing equipment.

Based on the above criteria, the following projects have been selected for rebuilds in the near future:

- Old Meadowvale Village Overhead Rebuild and Conversion
  This project involves voltage conversation of the system from 4.8/8.32 kV to 16/27.6 kV and replacement of 56 wood poles, 6 transformers, 4.5km of 556kcmil main feeder wires, 200m of 1/0 distribution feeder wires, 2.5km of 250kcmil secondary spun bus conductors, 3 in-line disconnect switches and transfer of 40 existing secondary services.
- Lorne Park Estates Rebuild
  The project encompasses the replacement of 52 wood poles, 9 transformers, 1.2km of 1/0 distribution feeder wires, 3.5km of 250kcmil secondary spun bus conductors, 2 in-line disconnect switches and transfer or 54 existing secondary services.
- Martley Drive
  The project includes the replacement of 15 wood poles, 2 transformers, 260m of 1/0 distribution feeder wires, 400m of 250kcmil secondary spun bus conductors and transfer of 25 existing services
- Orchard Rebuild
  Under this project 8 wood poles, 2 transformers, 250m of 1/0 distribution feeder wires, 500m of 250kcmil secondary spun bus conductors will be replaced. In addition, 35 existing secondary services will be transferred.
- Birchwood Creek Rebuild
  The project covers upgrade of 16 wood poles with concrete poles and replacement of 2 transformers, 1.8km of 3/0 distribution feeder wires, 750m of 250kcmil secondary spun bus conductors and transfer of 20 existing services.
- Bremen Lane Rebuild
  The project covers the replacement of 14 wood poles, 2 transformers, 300m of 1/0 distribution feeder wires, 600m of 250kcmil secondary spun bus conductors and transfer of 37 existing services.

- Cortland Crescent
  This project involves the replacement of 40 wood poles, 9 single phase transformers 2.4km of 1/0 distribution feeder wires, 2.5km of secondary spun bus conductors and 227 secondary services.
- Edenhurst Drive
  The project covers the replacement of 36 wood poles, 7 single phase transformers 2.8km of 1/0 distribution feeder wires, 3.0km of secondary spun bus conductors and 132 secondary services.
- Birchview Drive
  This project involves the replacement of 32 wood poles, 9 single phase transformers 3.35km of main feeder wires, 1.6km of secondary spun bus conductors and 48 secondary services.
- Clarkson Road South
  The project encompasses the replacement of 43 wood poles, 13 single phase transformers 3.0km of 1/0 distribution feeder wires, 2.8km of secondary spun bus conductors and 64 secondary services.
- Munden Road
  The project includes the replacement of 29 wood poles, 5 single phase transformers 800m of 1/0 distribution feeder wires, 2.2km of secondary spun bus conductors and 85 secondary services.
- The Greenway
  This project involves the replacement of 21 wood poles, 5 single phase transformers 900m of 1/0 distribution feeder wires, 2.0km of secondary spun bus conductors and 31 secondary services.
- Hydro Road
  Under this project, 10 wood poles and 1.8km of main feeder wires will be replaced.
- West Acers Phase 1
  The project covers the replacement of 30 wood poles, 9 single phase transformers 2.9km of main feeder wires, 1.9km of secondary spun bus conductors and 75 secondary services.
- Randor Road
  This project involves the addition of 11 wood poles, 2 single phase transformers 600m of 1/0 distribution feeder wires and 1.2km of secondary spun bus conductors.
- Sheppard phase 3
  This project includes the replacement of 58 wood poles, 7 single phase transformers 1.3km of 1/0 local distribution feeder wires, 1.7km of secondary spun bus conductors and 45 secondary services.
- Pine Avenue
  This project encompasses the replacement of 12 wood poles, 3 single phase transformers 400m of 1/0 local distribution feeder wires, 800m of secondary spun bus conductors and 43 secondary services.
- Blanefield Road
  This project covers the replacement of 76 wood poles, 12 single phase transformers 1.6km of 1/0 local distribution feeder wires, 3.2km of secondary spun bus conductors and 170 secondary services.
- Bexhill Road
  This project involves the replacement of 37 wood poles, 6 single phase transformers 1.2km of 1/0 local distribution feeder wires, 2.5km of secondary spun bus conductors and 64 secondary services.
- Larchview Trail
  Under this project 17 wood poles, 5 single phase transformers 600m of 1/0 local distribution feeder wires, 1.2km of secondary spun bus conductors and 46 secondary services will be replaced.
- West Avenue
  This project involves the replacement of 20 wood poles, 6 single phase transformers 350m of 1/0 local distribution feeder wires, 1.0km of secondary spun bus conductors and 37 secondary services.

- Alexandra Avenue
  This project includes the replacement of 44 wood poles, 8 single phase transformers 1.0km of 1/0 local distribution feeder wires, 2.0km of secondary spun bus conductors and 137 secondary services.
- West Acers Phase 2
  This project encompasses the replacement of 53 wood poles, 14 single phase transformers 2.2km of 1/0 local distribution feeder wires, 5.0km of secondary spun bus conductors and 165 secondary services.
- Roosevelt Road
  This project covers the replacement of 9 wood poles, 2 single phase transformers 200m of 1/0 local distribution feeder wires, 500m of secondary spun bus conductors and 21 secondary services.
- Kenollie Avenue
  This project involves the replacement of 74 wood poles, 17 single phase transformers 2.5km of 1/0 local distribution wires, 5.0km of secondary spun bus conductors and 170 secondary services.

Justification

- This program is needed to replace equipment that reaches end of life or becomes hazardous. The safe, reliable operation of the electrical distribution system depends on the condition of the assets.
- These overhead rebuilds are determined by an analysis of trouble call activity, age and an assessment of the future risks to public safety. Furthermore, these feeders will be identified after analysis of outages each year during storms and the heavy loading season in the summer.
- There is an ongoing program to replace entire sections of pole line and their associated hardware that have deteriorated through age.
- As a part of these overhead rebuild projects the replacement includes poles, primary and secondary conductors, down guys, brackets, cross arms and insulators along with transformers are all replaced so that the system is brand new.
- The replacement of these pole lines removes substandard poles from the system thereby maintaining reliability.

Alternatives

- Individual deteriorated or damage poles or overhead equipment can be changed as they are found on an interim basis to delay a rebuild, but eventually rest of the poles in the area will have to be replaced to avoid the risk of possible failures.

- Planned replacement of pole line costs much less than “emergency” or reactive replacements and are less disruptive to customers.

Impact of Deferral

There would be an increase in the risk of equipment failure under adverse conditions, leading to reduced reliability and safety hazards to the public and EHM personnel.

Results

- Eliminate safety hazards to the public and utility personnel
- Maintain customer reliability with reduced outage duration and frequency
- Replace end of life assets
- Improve reliability, power quality and the safe operation of the distribution lines facilities

Estimated Annual Expenditure ($ 1,000’s)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 1,350	$ 1,530	$ 1,710
Capital Costs funded by Others			
Total Capital Costs	**$ 1,350**	**$ 1,530**	**$ 1,710**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Overhead Distribution Upgrades**
BUSINESS UNIT #:	**C0561**
PROJECT NAME:	**2012/13/14 – 2 Overhead Switch Replacement Program**

Project Description

- This program is needed to ensure that the replacement of inoperable and end of life equipment such as overhead switches, cutouts and insulators is completed on an annual basis.
- This program funds the spot replacement of overhead switching equipment over various parts of the City that have been determined to be at the end of life.

The overhead distribution system has approximately 742 gang operated, three-phase, load break switches, 5,343 in-line solid blade switches, 724 cutouts, as well as other components.

Distribution line equipment deteriorates over time and must be replaced when reliability and safety risks reach unacceptable levels. Switches and insulators are essential elements of the electrical distribution system and when they become inoperable and reach end of life then replacement is required.

During switch maintenance or as a follow-up to trouble calls, a number of overhead switches are found to be beyond repair and require replacement. In addition, a program of replacing broken porcelain cutouts, porcelain insulators, porcelain mid-span openers with polymer insulators or solid blade switches on the electrical system will continue.

Overhead equipment is exposed to various adverse conditions and failure can occur as a result of a number of causes, some of which are described in the following:

- Mechanical stress on operating linkages, operating rods, springs and contacts due to wear and tear during fault interrupting conditions
- Exposure to contaminants, such as salt and pollutants and extreme environmental weather conditions
- Chemical contamination, such as dust and powder, produced by arc erosion during switching and fault interruptions
- Thermal stress because of localized heating and varying load currents

Justification

- This replacement program is needed annually to replace equipment that reaches end of life or becomes inoperable. The safe, reliable operation of the electrical distribution system depends on the condition of these assets
- It is expected that a combined total of 50 switches and load break devices will need to be replaced annually
- A program of upgrading insulators in high contamination areas and replacing specific types of insulators prone to early failure will continue on an annual basis
- Aside from this program, switches are also replaced under other programs including those dealing with trouble calls, storm damage, overhead rebuilds, line relocations and from road projects.

Alternatives

Deteriorated or damage switches or insulators need to be changed as they are found because they support the overhead electrical distribution system. The more circuits on the pole the more likelihood of needed rapid replacement due to the large amount of customers that would be connected to the circuits they service.

Switch replacement can be temporarily delayed depending on the number of customers that could be affected by the switch breaking but ultimately need replacement at some point.
Sometimes replacement is delayed if the area is destined for a complete overhead rebuild or there will be another project like a road widening coming up. In these cases the switch is removed from service or bypassed.

Insulators depending on how bad they are tracking can also be delayed but ultimately need to be replaced.

Impact of Deferral

There would be an increase in the risk of equipment failure under adverse conditions, leading to reduced reliability and safety hazards to the public and EHM personnel.

Over the long term there is a strong business need to replace this equipment in a proactive manner.

Results

- Eliminate safety hazards to the public and utility personnel
- Maintain customer reliability with reduced outage duration and frequency
- Replace end of life assets
- Improve reliability, power quality and safe operation of the distribution lines facilities.

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board	$ 360	$ 360	$ 360
Capital Costs funded by Others			
Total Capital Costs	**$ 360**	**$ 360**	**$ 360**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Overhead Distribution Upgrades**
BUSINESS UNIT #:	**C0561**
PROJECT NAME:	**2012/13/14 – 3 Wood & Concrete Pole Replacement Program**

Project Description

- This program is needed to ensure that substandard wood poles, cross arms and concrete poles that have reached their end of life are replaced on an annual basis.
- A major component of EHM's overhead distribution system is wood and concrete poles. EHM's has approximately 12,995 wood poles and 7,508 concrete poles which support approximately 1,787km of overhead primary and over 1,253 km of overhead secondary circuits.
- This program funds the spot replacement of poles over various parts of the City that have been determined to be at the end of life.

Poles deteriorate over time and when their strength is reduced to the point that there is a risk of failure under adverse weather conditions then they are deemed to be at end of life. The safe, reliable operation of the distribution system depends on the condition of pole assets.

Pole condition is routinely assessed by operational personnel performing work on a pole such as switching or other asset replacement (transformers, insulators, lightning arrestors, etc.). The outside crews advise the Overhead Maintenance Supervisor directly or the Control Room of poles that are in poor condition. If the Control Room gets the information they generate a report and sent it to the Overhead Maintenance Supervisor for follow-up. Outside employees who are on light duty from injury are also sometimes given sections of the City to visually inspect the condition of the existing equipment.

Justification

- There is an ongoing program to replace wood or concrete poles that have deteriorated through age.
- Based on past experience it is projected that approximately 40 poles will need to be replaced each year with their associated hardware such as insulators and cross arms. Cross arms typically support conductors and associated insulating equipment and provide separation between energized components and publicly used roads, driveways and right-of-ways.
- Poles and cross arms are also replaced when they pose safety and reliability hazards.
- Aside from this program, poles are also replaced under other programs including those dealing with trouble calls, storm damage, system capability reinforcement, sustainment projects, line relocations and from road projects.
- The replacement of these poles removes substandard poles from the system thereby maintaining reliability.
- Planned replacement of poles costs much less than "emergency" or reactive replacements and are less disruptive to customers.

Alternatives

Deteriorated or damage poles need to be changed as they are found because they support the overhead power system.

Pole replacement can be temporarily differed depending on the number of customers that could be affected by the pole breaking but ultimately the poles will need replacement at some point.

Sometimes replacement is delayed if the area is destined for a complete overhead rebuild or there will be another project like a road widening coming up.

Impact of Deferral

There would be an increase in the risk of equipment failure under adverse conditions, leading to reduced reliability and safety hazards to the public and EHM personnel.

Over the long term there is a strong business need to replace poles in a proactive manner.

Results

- Replace end of life assets
- Eliminate safety hazards to the public and utility personnel
- Maintain customer reliability with reduced outage duration and frequency

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board	$ 540	$ 838	$ 989
Capital Costs funded by Others			
Total Capital Costs	**$ 540**	**$ 838**	**$ 989**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Underground Distribution Upgrades**
BUSINESS UNIT #:	**C0565**
PROJECT NAME:	**2012/13/14 – 1 Pad Mounted Switchgear Replacement**

Project Description

- The program is needed to ensure the replacement of sub-standard underground equipment that has caused outages or has reached end of life is completed on an annual basis.
- Underground distribution equipment deteriorates over time and must be replaced when reliability and safety risks reach unacceptable levels. Pad mounted switchgears (PMH units) are one of the essential elements of the underground electrical distribution system and when they become inoperable or reach end of life then replacement is required.
- This program funds the spot replacement of underground PMH units, over various parts of the City, that have been determined to be at the end of life.
- The underground distribution system has approximately 773 PMH units
- This project provides for the replacement of approximately 15 pad mounted switchgears on an annual basis that are beyond repair and need replacement.

Equipment condition is routinely assessed by operational personnel performing work in the area such as switching or other asset replacement (transformers, cables etc.) or from responding to power outages. The outside crews advise the Underground Maintenance Supervisor directly or the Control Room of underground equipment that is in poor condition. If the Control Room gets the information they generate a report and sent it to the Underground Maintenance Supervisor for follow-up. Outside employees who are on light duty from injury are also sometimes given sections of the City to visually inspect the condition of existing underground equipment.

Aside from this program, underground equipment is also replaced under other programs including those dealing with cable replacement, trouble calls and subdivision rebuilds.

Justification

From EHM's reliability statistics it is evident that equipment failures greatly contribute to decline in reliability over the past few years. The air insulated switchgear failures are mainly caused by tracking due to contamination, old age, design configurations and application voltage levels. This results in power quality, reliability and maintenance issues. Each year Enersource have been replacing units due to premature failures. These types of faults typically expose customers to multiple momentary power interruptions. This can take several days to troubleshoot and locate the faulty unit. As our system ages, this has the potential to become more prevalent.

Switchgears are essential elements of the electrical distribution system and when they become inoperable and reach end of life then replacement is required.

Alternatives

- PMH units can be cleaned by a dry ice process to lengthen there life but this is only effective for the medium term. Flash overs in PMH units are becoming more pronounced as they age and especially in weather that is prone for tracking. This typically occurs from early dew in the morning or from contamination from road salt, especially near major road ways.

- Sometimes if an underground rebuild is coming soon these projects can be delayed. The replacement of this equipment removes sub-standard equipment from the system thereby maintaining reliability. Planned replacement of underground equipment costs much less than “emergency” or reactive replacements and are less disruptive to customers. Over the long term there is a strong business need to replace underground equipment in a proactive manner.

Impact of Deferral

There would be an increase in the risk of equipment failure under adverse conditions, leading to reduced reliability and safety hazards to the public and EHM personnel.

Results

- Maintain customer reliability with reduced outage duration and frequency
- Replace end of life assets
- Eliminate safety hazards to the public and utility personnel
- Improve reliability, power quality and safe operation of the underground equipment

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 1,107	$ 1,199	$ 1,291
Capital Costs funded by Others			
Total Capital Costs	**$ 1,107**	**$ 1,199**	**$ 1,291**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Underground Distribution Upgrades**
BUSINESS UNIT #:	**C0565**
PROJECT NAME:	**2012/13/14 – 2 Primary Distribution Equipment Replacement**

Project Description

- The program is needed to ensure the replacement of sub-standard underground equipment that has caused outages or has reached end of life is completed on an annual basis.
- Underground distribution equipment deteriorates over time and must be replaced when reliability and safety risks reach unacceptable levels. This equipment is a part of the underground electrical distribution system. Without it the main components of the system such as transformers or switchgears becomes inoperable, therefore, replacement of this equipment is necessary before it fails.
- This program funds the spot replacement of underground equipment such as fault indicators, arrestors, elbows and inserts over various parts of the City

Equipment condition is routinely assessed by operational personnel performing work in the area such as switching or other asset replacement (transformers, cables etc.) or from responding to power outages. The outside crews advise the Underground Maintenance Supervisor directly or the Control Room of underground equipment that is in poor condition. If the Control Room gets the information they generate a report and sent it to the Underground Maintenance Supervisor for follow-up. Outside employees who are on light duty from injury are also sometimes given sections of the City to visually inspect the condition of existing underground equipment.

Aside from this program, underground equipment is also replaced under other programs including those dealing with cable replacement, trouble calls and subdivision rebuilds.

Justification

Fault Indicators

- Fault indicators flash or turn red when fault current passes through them and are used for trouble shooting during power outages. However the overhead fault indicators typically only last about 10 years because there battery runs down and need replacement. Also, the older type of fault indicators have had issues with water damaging internal components and permanently damaging them. The newer fault indicators utilize better technology so the old type of the fault indicators are completely replaced.
- Underground fault indicators are changed when they are found to give false readings during power outages and when the display becomes unreadable.
- EHM installs fault indicators on the overhead wires, in PMH units and in transformers to help with trouble shooting during cable failures.
- An independent report on useful life of equipment was done by Kinectrics for EHM recently that gives the life expectancy for fault indicators be in the range of 5 to 20 years for overhead units and 10 to 30 for underground fault indicators. We have found through our own past experience that 10 years for the overhead indicators and 20 years for underground indicators is a typical useful life.

Arrestors, Elbows and Inserts

- There is an ongoing program to replace arrestors, elbows and inserts in transformers and their associated hardware that have been identified as deteriorated.
- These are usually found by underground crews doing switching or from the trouble truck responding to power outages.
- Typically the pulling eyes on elbows that are used to open & close devices in transformers are found to be in poor shape after 20 to 25 years and need changing along with their inserts.
- An independent report on useful life of equipment was done by Kinectrics for EHM recently that defines the expected useful for elbows and inserts to be in the range of 20 to 60 years and we have found through our own practice that 20 years is typical.

Alternatives

- Fault indicator replacement cannot be delayed because it will give wrong indication as to where a fault may be located which would cause much longer power outages.
- Arrestors, elbows and insert replacement can be delayed, but not being able to operate this equipment when needed can cause much longer power outages.
- Sometimes if an underground rebuild is coming up some of these projects can be delayed. The replacement of this equipment removes sub-standard equipment from the system thereby maintaining reliability. Planned replacement of underground equipment costs much less than "emergency" or reactive replacements and are less disruptive to customers. Over the long term there is a strong business need to replace underground equipment in a proactive manner.

Impact of Deferral

There would be an increase in the risk of equipment failure under adverse conditions, leading to reduced reliability and safety hazards to the public and EHM personnel.

Results

- Maintain customer reliability with reduced outage duration and frequency
- Replace end of life assets
- Eliminate safety hazards to the public and utility personnel
- Improve reliability, power quality and safe operation of the underground equipment

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 461	$ 461	$ 461
Capital Costs funded by Others			
Total Capital Costs	**$ 461**	**$ 461**	**$ 461**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Underground Distribution Maintenance**
BUSINESS UNIT #:	**C0565**
PROJECT NAME:	**2012/13/14 – 3 Underground Cable & Splice Replacement**

Project Description

- Every year a number of underground primary cables and splices fail which results in outages to customers. Depending on the cable that faults this can result in very large outage times.
- The program is needed to replace sections of underground primary cables and splices that have experienced failures in excess of acceptable standards and require immediate replacement on an annual basis.

Justification

- This program was developed on the basis of reliability improvements rather than age demographics. Potential projects are identified based on the total number of customer-hours of interruption due to cable or heat shrink splice failures. These are typically older sections of underground primary cable that have fallen into disrepair over time and where replacement costs are extremely high.
- Sometime cables fail prematurely from dig ins, high loading causing heat, poor installation methods, not having a jacket around the cable or the cable being direct buried instead of being installed in PVC or concrete pipe.
- Primary cables and splices are essential elements of the electrical distribution system and when they become inoperable and reach end of life, their replacement is required.
- If the cable fault has been due to insulation failure then repairs are made by doing a cable splice.
- If the same section of cable has had insulation failures three times in a short period of time and no other cables have failed in the same general area then the practice is to replace that section of cable immediately. EHM tracks cable failures so that we are aware of how many times a section of cable have failed.
- If many primary cables in the same general area have failed then a full underground cable rebuild is done.
- In some cases splices are found to be the cause of the outage and EHM would then splice the cable again. If only one cable of a three phase circuit fails then EHM's practice is to replace all 3 splices at the same time since the pit is already dug.
- Cable and splice failures still remain the largest contributor to EHM's customer outage time.

Alternatives

Cables and splices can be left not repaired but this would mean backup to customers would be unavailable. If another section fails then a very lengthy outage could result until emergency repair work is done.

Instead of replacing a section of cable another splice could be done but once a cable's insulation starts failing the cable will likely fail again causing another outage.

EHM may sometimes try to rehabilitate primary cables in a cable rejuvenation process that has used in the past that involves silicon injection. This process has established itself in the industry as a viable alternative to replacing cables and is used where replacing cables is very expensive.

One splice could be repaired instead of doing all three splices but if the splices are all of the same age and done by the same installer then the likelihood will be that the other splices will also fail soon after. This would result in another outage at the same location. Therefore to prevent future failures and the associated costs, EHM's practice is to replace all splices at one location.

Results

- Maintain customer reliability with reduced outage duration and frequency
- Replaced end of life assets
- Eliminate safety hazards to the public and utility personnel
- Improve reliability, power quality and safe operation of the underground equipment

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board	$ 922	$ 1,245	$ 1,384
Capital Costs funded by Others			
Total Capital Costs	**$ 922**	**$ 1,245**	**$ 1,384**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Transformer Replacements**
BUSINESS UNIT #:	**C0563**
PROJECT NAME:	**2012/13/14 – 1 Pad Mounted Transformer Replacement**

Project Description

- The program is needed to allow for the planned and unplanned replacement of underground transformers that are in poor condition in various parts of the City. This program provides for equipment that requires immediate replacement.
- Every year a number of transformers fail which results in outages to customers. Sometimes transformers are found to be severely leaking oil and require changing before they fail. A transformer failure in a residential area may only affect 10 to 12 customers so outage time is minimal. However a transformer failure for an industrial/commercial could prove costly to their business.
- Transformers are essential elements of the electrical distribution system and when they fail they must be immediately replaced.
- This program includes the unplanned and planned replacement of underground distribution transformers.

There are over 19,765 underground transformers on the system. This spending allows for the replacement of approximately 35 transformers on the underground system on an annual basis.

Justification

- Transformer condition is routinely assessed by operational personnel performing work such as switching, responding to trouble calls or outages. The outside crews advise the Underground Maintenance Supervisor directly or inform the Control Room of transformers that are in poor condition typically leaking oil or rusting badly. If the Control Room gets the information they generate a report and sent it to the Underground Maintenance Supervisor for follow-up.
- Outside employees who are on light duty from injury are also sometimes given sections of the City to visually inspect the condition of existing underground equipment.
- During inspection a number of leaking and rusting transformers are identified on an annual basis that requires replacement.
- Single phase transformers for residential customers are typically run to failure rather than replaced proactively due to their low cost and low customer minute impact.
- Typical replacement cost of a single phase pad mounted transformer is approximately $16,000
- In the past, many transformers were tested for PCB content. Through this survey transformers were visited up-close and those requiring immediate attention were changed out. Some transformers were identified for future replacement by the underground department.

Planned replacement of transformers costs much less than “emergency” or reactive replacements and are less disruptive to customers. Over the long term there is a business case need to replace transformers in a more proactive manner.

Alternatives

Individual underground transformers that failed, are rusting or are leaking badly need to be changed out as they are found. Depending on the amount of leakage sometimes the transformer does not need to be changed out immediately but will be done later.

Sometimes if an underground rebuild project is imminent in the area then transformer change out can also be delayed.

The replacement of this equipment removes substandard transformers from the system thereby maintaining reliability.

Impact of Deferral

There would be an increase in the risk of equipment failure under adverse conditions, leading to reduced reliability and safety hazards to the public and EHM personnel.

Results

- Mitigate potential environmental liabilities from leaking oil
- Maintain customer reliability with reduced outage duration and frequency
- Replaced end of life assets
- Eliminate safety hazards to the public and utility personnel
- Improve reliability, power quality and safe operation of the underground equipment

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 548	$ 639	$ 730
Capital Costs funded by Others			
Total Capital Costs	**$ 548**	**$ 639**	**$ 730**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Protection & Control, Automation and SCADA Upgrades**
BUSINESS UNIT #:	**C0576**
PROJECT NAME:	**2012/13/14 – 1 Remotely Controlled Switches**

Project Description

- This project is required to reduce outage time duration, improve system reliability and operational flexibility by targeting underperforming subtransmission and distribution feeders by installing automation at key switching locations.
- A cost effective approach to improve reliability of supply to EHM customers is to install automation at strategic locations along a feeder. Typically this location is at an open switch and at the mid-point of the feeder
- As part of the strategy to improve overall system reliability, the worst performing feeders are typically targeted and/or feeders that have high customer counts.
- Automation is done only on 44kV, 16/27.6kV and 13.8kV feeders because these have the greatest impact on reliability with respect to the number of customers served and the load supplied and because automation is expensive. Typically the higher the voltage the higher the customer count and the greater the exposure.

Justification

- Typically several feeders suitable for automation are selected from a list of the underperforming feeders.
- This ongoing program is part of a longer term initiative to improve reliability and to maintain reliability to what EHM's customers have become accustomed to.
- EHM also compare reliability results to similar utilities, for both System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency (SAIFI).
- Automation and SCADA components require refurbishment because they lose their capability to perform as intended. The component replacement program addresses individual assets, such as Substation Remote Terminal Units, Pole Top Remote Terminal Units (RTUs), protection relays and battery chargers that have reached the end of their service lives and are no longer capable of fulfilling their intended function reliably. Presently, EHM has 56 Pole Top RTUs and 39 Substation RTUs that are 20 years old. This continuing project will see all RTUs replaced in 5 years.

Impact of Deferral

Not proceeding with this project would result in a decline in reliability due to the increase in time to respond to system problems.

It would also expose the substations to undue risks such as Power Transformer temperature alarms, as these alarms would be unmonitored from the System Control Centre.

Results

- Reduced outage duration for individual distribution feeders supplying distribution customers where automation has been installed
- Improved customer satisfaction
- Improved operational flexibility and response time to outages
- Maintain reliable communication to remotely monitor and control EHM's critical infrastructure from the System Control Centre

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 829	$ 1,013	$ 1,198
Capital Costs funded by Others			
Total Capital Costs	**$ 829**	**$ 1,013**	**$ 1,198**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Maintenance - Reliability Driven Investments**
INVESTMENT NAME:	**Protection & Control, Automation and SCADA Upgrades**
BUSINESS UNIT #:	**C0576**
PROJECT NAME:	**2012/13/14 - 2 RTU's, Protection & Control Relays and Battery charger replacement/addition**

Project Description

- This project is required to replace aging RTU's, Protection Relays and battery chargers that have reached end of life.
- This project also includes the addition of new RTU's, Protection Relays and battery chargers for our Substations and Field automated devices.

Justification

- Automation and SCADA components require refurbishment because they lose their capability to perform as intended. The component replacement program addresses individual assets, such as Substation Remote Terminal Units, Pole Top and Pad Mounted Remote Terminal Units (RTUs), protection relays and battery chargers that have reached the end of their service lives and are no longer capable of fulfilling their intended function reliably. Presently, EHM has 56 Pole Top RTUs and 39 Substation RTUs that are 20 years old. This continuing project will see all RTUs replaced in 5 years.

Impact of Deferral

Not proceeding with this project would result in a decline in reliability due to the increase in time to respond to system problems.

It would also expose the substations to undue risks such as Power Transformer temperature alarms, as these alarms could go unmonitored from the System Control Centre.

Results

- Reduced outage duration for individual distribution feeders supplying distribution customers where automation has been installed
- Improved customer satisfaction
- Improved operational flexibility and response time to outages
- Maintain reliable communication to remotely monitor and control EHM's critical infrastructure from the System Control Centre

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 553	$ 737	$ 921
Capital Costs funded by Others			
Total Capital Costs	$ 553	$ 737	$ 921

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Expansion & Upgrades - Customer Driven Investments**
INVESTMENT NAME:	**Industrial/ Commercial Customer Services**
BUSINESS UNIT #:	**C0542**
PROJECT NAME:	**2012/13/14 - Industrial/ Commercial Customer Services**

Project Description

- This project is required to meet the ongoing demand to connect new industrial/commercial customers to the electrical distribution system and for existing customer service upgrades.
- New industrial/ commercial or upgrade projects are initiated by developers and property owners every year and EHM has an obligation to connect them to the power system.

EHM tracks new developments from land use information and plans (i.e. subdivision concept, draft plans and rezoning applications) provided by the City of Mississauga's Planning & Building department and use this information to estimate loading requirements. The number of site plans and rezoning applications are a good indication of capital expenditures required in industrial/ commercial construction in future years. Influences for commercial development include the state of the local economy and commercial vacancy rates. The majority of the work is in the north-central area of the City in the north-west end. Growth has been slow but steady over the past few years.

Justification

Each year, new customers are connected to the system and customers do upgrades to their existing buildings.

- As a part of the distribution license and the distributor's responsibility in the Distribution System Code, EHM is required to connect all customers on a non-discriminatory basis upon written request for connection.
- A service upgrade occurs when an existing customer requires a larger service entrance. A service upgrade requires the preparation of a service layout and replacement of secondary service cables. Transformers may also have to be upgraded and metering replaced.

Projects costs include design (service layouts), labour, material, inspection and other costs associated with actual physical connection.

The expected expenditures for 2012 and beyond are based on 2011 forecasts, historical levels, the projected growth rate, prior year project carry-over, and project inquiries. As budgeting in this area is not based on a project list, no specific project(s) can be highlighted as the cause of the expenditures.

The following table shows the yearly connection trend for the previous few years and future projections:

Year	# of Connections
2008	355
2009	397
2010	162
2011	336
2012	250 (Estimate)
2013	250 (Estimate)
2014	250 (Estimate)
2015	200 (Estimate)

Impact of Deferral

Not proceeding with this project would result in non-compliance with EHM's distribution license requirements and with EHM's obligations under the Distribution System Code. This work is therefore a regulatory requirement.

Results

- Connect new customers and upgrade the services of the existing customers
- Satisfy the requirements of the Distribution System Code and EHM's distribution license

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board	$ 1,326	$ 960	$ 960
Capital Costs funded by Others	$ 1,600	$ 1,600	$ 1,600
Total Capital Costs	**$ 2,926**	**$ 2,560**	**$ 2,560**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Expansion & Upgrades - Customer Driven Investments**
INVESTMENT NAME:	**New Subdivision Connections & Capital Contribution Refunds**
BUSINESS UNIT #:	**C0541**
PROJECT NAME:	**2012/13/14 - New Subdivision Connections & Capital Contribution Refunds**

Project Description

- This project is required to meet the ongoing demand to connect new subdivisions to the system and to provide for capital contribution refunds to developers.

New subdivision projects are initiated by developers and property owners. EHM tracks new developments from land use information and plans (i.e. subdivision concept, draft plans and rezoning applications) provided by the City of Mississauga's Planning & Building department and use this information to estimate loading requirements. The number of concept draft plans and rezoning applications is a good indication of capital expenditures required in residential construction in future years. Subdivision development is primarily dependent on the local economy. The majority of the residential work is in the central area of the City in the west end. Growth has been steady over the past few years with condominiums and townhouses dominating the new construction.

Justification

EHM connects these new subdivisions to the system as a part of the obligation in EHM's electricity distribution license and the distributor's responsibility in the Distribution System Code. EHM is required to make an "Offer to Connect" to all customers on a non-discriminatory basis upon written request for connection. Residential Subdivision contributions are determined through the use of the Ontario Energy Board's (the "Board") prescribed economic evaluation methodology. Inputs into the model include projected load characteristics of the subdivision, the value of contributed plant and EHM's expenditures to service the subdivision. Trending year over year shows that the amount of cost recovery through financial contributions has followed the same trend as EHM's expenditures.

For customers that require expansion of the distribution system in order to connect a new customer/ subdivision, a discounted cash-flow model is used to determine customer contributions. The capital contribution is based on any shortfall between future revenues and the cost of connection, expansion and reinforcement. The subdivision project costs budgeted expenditures for 2012 and beyond are based on 2011 forecasts.

The following table shows the yearly connection trend for the previous few years and future projections:

Year	# of Connections
2008	3,144
2009	2,900
2010	1,129
2011	2,481
2012	2,450 (Estimate)
2013	1,950 (Estimate)
2014	3,050 (Estimate)
2015	1,500 (Estimate)

It is anticipated that there will be approximately 2,000 new services required for next year. The number of new services to be connected is mainly due to the fact that condominium/apartments are now mostly individually metered.

Impact of Deferral

Not proceeding with this project would result in non-compliance with EHM's distribution license requirements and with obligations under the Distribution System Code. This work is therefore a regulatory requirement.

Results

- Connect new subdivision projects and upgrade the services of existing customers
- Satisfy the requirements of the Distribution System Code and EHM's distribution license

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board	$ 1,843	$ 1,647	$ 1,647
Capital Costs funded by Others	$ 600	$ 600	$ 600
Total Capital Costs	**$ 2,443**	**$ 2,247**	**$ 2,247**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Expansion & Upgrades - Customer Driven Investments**
INVESTMENT NAME:	**Road Projects**
BUSINESS UNIT #:	**C0531**
PROJECT NAME:	**2012/13/14 – Road Projects**

Project Description

- This project covers joint use work that EHM is obligated to provide in order to meet its contractual obligations to the City of Mississauga, Regional of Peel, Hydro One and the Ministry of Transportation.

This work covers changes/ upgrades to EHM distribution assets to accommodate the needs of joint use partners. The requests may also result in pole class and height changes to accommodate increases in pole loading and to obtain appropriate ground clearances for public safety.

Justification

EHM installs the majority of its infrastructure along road right of ways that are owned and managed by the City of Mississauga and the Region of Peel at no cost to the utility. EHM distribution equipment occupies road allowances at no cost and in return is required to remove, relocate or reconstruct its facilities in order to accommodate the specific requirements of the road authorities. Their road works program largely drives plant relocation and is located throughout the City. This work can impact both overhead and underground distribution plant. Typically there is some capital contribution as per the *Public Service Works on Highways Act*. EHM typically recovers 50% labour and labour saving devices.

The amount of relocation work is primarily dependent on the economy and on various levels of government funding. The City establishes a road works program for each year but frequent and sudden changes occur which makes it extremely difficult to accurately forecast this project section. The City undertakes a number of projects every year to maintain and expand its infrastructure, but these lists are not typically finalized until the year the work occurs in.

EHM does try to anticipate these requests of possible pending works through participation in meetings with the City and the Region and through review of City site plans and zoning amendments. The expected financial impact on EHM of plant relocation is based on historical levels, previous year project carry-over and discussions with the City.

The City has received infrastructure stimulus funding, and consequently City driven “plant relocation” projects are moving ahead rapidly.

In 2012 and 2013 EHM will support the new Bus Rapid Transit (BRT) project being undertaken by relocating electrical plant at the following locations:

- Eglinton Avenue East - Etobicoke Creek to Satellite Drive
- Eglinton Avenue East - Satellite Drive to Orbitor Drive
- Eglinton Avenue East - Orbitor Drive to Commerce Boulevard
- Winston Churchill Boulevard to Erin Mills Parkway

This work will have a significant impact on manpower and ability to do new capital work.

Impact of Deferral

EHM has a legal obligation to move or remove their equipment when asked to by the City, Region, MTO and other governmental bodies.

Results

- EHM will meet its contractual and legal obligations
- Maintain property rights for EHM circuits located on road allowances

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board	$ 1,176	$ 1,087	$ 999
Capital Costs funded by Others	$ 600	$ 600	$ 600
Total Capital Costs	**$ 1,776**	**$ 1,687**	**$ 1,599**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Expansion & Upgrades - Customer Driven Investments**
INVESTMENT NAME:	**Metering Equipment**
BUSINESS UNIT #:	**C0598**
PROJECT NAME:	**2012/13/14 - 1 Metering Equipment**

Project Description

Distribution revenue metering is set into two categories: retail metering and wholesale metering. This narrative outlines the business case for retail metering. Revenue metering is federally regulated under the Electricity and Gas Inspection Act (E&GIA), governed by Measurement Canada (MC). Under MC regulations, all revenue meters must be approved, routinely inspected and maintained. EHM must comply with Measurement Canada rules and regulations. Routinely, the revenue meters must be removed from service and verified of performing accurately and within MC accuracy specification ranges. Verification of the meter performance is completed by a MC accredited meter verifier using certified equipment as required by the Act.

Justification

Under MC regulations, retail electricity customers require a revenue meter for measuring and billing electricity use. EHM owns and operates approximately 193,000 retail revenue meters. Historically, approximately 500 of these revenue meters were removed or replaced each year due to random failures, damage or functional obsolescence. In addition, on average 500 meters are removed and replaced as part of meter verification requirements defined in regulations administered by Measurement Canada. Meter verifications are carried out in compliance with Measurement Canada rules. For certain class of meters, “grouping” is an accepted MC practice. Grouping means that a sample set of meters is removed from service for verification. If the sample group passes the verification test, then the remainder of the lot is accepted as accurate. If the sample of the group fails the verification test, the remainder of the lot may need to be replaced.

Recent changes to MC regulations impact meter verification practices. Specifically, the selection and method of grouping as well as complete lot verification of meters used in Individual Suite Metering

The accuracy of revenue meters is required to ensure customers are accurately billed.

The spending level provided is based on installing metering hardware such as current transformers, potential transformers along with other miscellaneous parts such as cable wires, test blocks and meter rings and seals required to complete the installation.

New installations support the growth of EHM’s customer base and the operation and maintenance of new and existing metering equipment and back office systems which collect and provide automated meter reading data for billing EHM customers.

The reliability of the metering equipment and back office AMI systems is paramount to the on-going billing of all Enersource customers and directly impacts EHM’s revenue stream. New installation must be completed within specific timeframes and are governed by the OEB regulations. Equipment must be available in sufficient quantities to allow timely completion of this work. Maintenance of existing metering installations remains a critical function to ensure consistent and complete data for billing on a regular basis and to provide data to the provincial MDM/R as mandated in the Functional Specification for an Advanced Metering Infrastructure dated July 5, 2007.
Incorrect installation, setup, lack of maintenance could result in a metering failure resulting in incorrect billing, loss of revenue, and possible damage to EHM’s reputation.

Results

- Ensures sufficient inventory of metering equipment for prompt installation of new services or replacement of damaged metering equipment.

- Efficient and accurate meter installation and replacement ensures that all Measurement Canada and any other applicable regulatory requirements are upheld.
- The investment also includes upgrading of existing metering due to customer electrical service upgrades, replacing obsolete or damaged meters and conversion from 2.5 element to 3 element metering.
- Maintenance and upgrades to Back Office Systems supports on-going data collection and billing

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 952	$ 695	$ 760
Capital Costs funded by Others			
Total Capital Costs	**$ 952**	**$ 695**	**$ 760**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**System Expansion & Upgrades - Customer Driven Investments**
INVESTMENT NAME:	**Smart Metering in Condominiums**
BUSINESS UNIT #:	**C0899**
PROJECT NAME:	**2012/13/14 – 1 Smart Metering in Condominiums**

Project Description

Smart Metering in Condominiums is part of the Government's plan to create a conservation culture in Ontario. The legislation provides condominium boards with the authority to have smart meters installed within their building.

Enersource Hydro Mississauga (EHM) provides individual metered suites (IMS) as an option for both new and existing condominium buildings. This option ensures Enersource remains compliant with the Distribution System Code (section 5.1.9 " When requested by a master consumer, a distributor shall install unit smart meters that meet the specifications prescribed by Ontario Regulation 389/10". Smart Metering also provides the building owner with the ability to individually meter the suites within the building.

Justification

Historically, condominium buildings were bulk metered and received one bill for the entire building. This electricity bill was paid by the condominium corporation and included suites and common area electricity usage. Under this scenario, there was little incentive to reduce electricity demand within the suites because the electricity costs were included uniformly in the condominium fee. Suite owners were not directly responsible for their own electricity which may have resulted in higher overall electricity usage. With the implementation of suite meters, suite owners are now given the opportunity to manage their own electricity use. Benefits of this program include , but are not limited to,

- Suite metering promotes conservation. Suite owners pay only what they use. Suite metering is the most equitable way to accurately allocate electricity costs.
- Suite owners now have a tool to monitor and manage their own usage.
- Suite owners are encouraged to participate in energy conservation programs to further reduce their electricity usage

Similar to the residential and general service system, the Smart Metering System for new condominiums meets AMI functional Specifications. An Advance Metering Infrastructure (AMI) utilizes the Meter Data Management Repository (MDM/R) and Time of Use (TOU) billing functionality enabled in EHM's Customer Information System (CIS). The AMI infrastructure includes the smart meter, regional collector via the local area network and the controller computer. The Smart Meter System for condominiums interfaces to the MDM/R and uploads daily consumption information for all the customers into the central MDM/R system. The MDM/R receives the data, validates, estimates and prepares the meter data for billing. The billing data is then sent by the MDM/R to the EHM's CIS system for customer billing.

EHM is responsible for installing, is work and processes that require to be put in place for a fully functional smart meter system, including

- Project management
- Deployment logistics
- Mobile workforce management
- Customer & community communications
- Process re-engineering
- Interface development to the MDM/R
- System testing
- Contract management
- Audit of system security
- Quality control
- System procurement
- System installation

The spending level outlined in the estimated annual expenditure table is based on installation of IMS equipment. Condominium construction projects in Mississauga continue positive since 2009 and it is forecasted to have consistent growth towards 2014. In 2011 EHM installed approximately 1400 suite meters. The 2012, 2013 forecast indicate an increase as a result of our experience to date, which is the uptake of new construction condominium building by developers in Mississauga. The increase in annual expenditures in 2014 is a result of the forecasted uptake in the existing building market. It is anticipated that new construction in 2014 is consistent to 2012 and 2013, but there will be increased activity in the existing building market.

Results

- Ensures capital is in place to meet the existing and future demand of condominium markets in Mississauga.
- Enables EHM to fulfill it's LDC requirements under the DSC
- Supports the governments initiative of creating a conservation culture in Ontario
- Provides suite owners with the ability to manage their own electricity

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 977	$ 952	$ 1,383
Capital Costs funded by Others			
Total Capital Costs	**$ 977**	**$ 952**	**$ 1,383**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements – Regulatory Driven Investments**
INVESTMENT NAME:	**Wholesale Metering**
BUSINESS UNIT #:	**C0597**
PROJECT NAME:	**2012/13/14 – 1 Wholesale Metering**

Project Description

All wholesale metering installations used for settlement in the IESO-administered market must be registered with the IESO and inline with the IESO Market Rules Chapter 6, section 3.2. Also, the metering installation shall comply in accordance to Measurement Canada's Electricity & Gas Inspection Act. Specifically, all instrument transformers and meters must be approved by Measurement Canada (MC). If any of the Instrument Transformers (IT) is not approved by MC, the non-compliant ITs must be replaced at the earliest seal expiry date.

Justification

All market participants are required to take over ownership of their wholesale meters from Hydro One per the Market Rules. Most of these existing metering installations require an upgrade to meet current IESO and MC standards. EHM is responsible for the costs of installing and maintaining the metering installations. However, EHM must contract the services of an IESO-registered Metering Service Provider (MSP) who is authorized to undertake the registration of the wholesale meter installation for operation in the IESO wholesale electricity market. Furthermore, EHM is required to contract Hydro One to perform some components (i.e. construction, installation and commissioning) of the upgrade since the transformer stations are Hydro One's property and related work must only be completed by Hydro One.

The use of non-approved ITs must end by December 31st of 2012, which is the year MC temporary permission expires. By end of 2012, sixteen (16) wholesale metering installations will require to be fully upgraded as a result of expiry of MC temporary permission.

Cooksville T3 - Q Bus	Cooksville T4 - J Bus
Cooksville T5 - B Bus	Cooksville T6 - Y Bus
Lorne Park T1 - B Bus	Lorne Park T1 - J Bus
Lorne Park T2 - B Bus	Lorne Park T2 - J Bus
Erindale T1 - E Bus	Erindale T1 - Q Bus
Erindale T2 - E Bus	Erindale T2 - Q Bus
Erindale T3	Erindale T4
Meadowvale T1 - E Bus	Meadowvale T2 - Z Bus

The above upgrade projects extend from 2011 to 2012 due to the constrain imposed by Hydro One's schedule and availability as other LDCs in Ontario require Hydro One services to complete their upgrades. Hydro One employs "First-Come-First-Serve" approach; Due to large number of wholesale metering upgrades being done by Hydro One across Ontario, a project can take 1.5 – 2 years to complete.

Supporting Documentation

http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter6appx.pdf

http://www.ieso.ca/imoweb/pubs/marketRules/mr_chapter6.pdf

Results

Upgrade of non-compliant wholesale meters at the most economical cost will:

- Bring metering installation inline with IESO Market Rules and Measurement Canada requirements

- Ensure higher accuracy of wholesale line losses calculation
- Mitigate risk of using legacy IT equipments which replacement parts may not be available for

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board	$2,779	$0	$0
Capital Costs funded by Others			
Total Capital Costs	**$2,779**	**$0**	**$0**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements – Regulatory Driven Investments**
INVESTMENT NAME:	**Smart Metering**
BUSINESS UNIT #:	**C0599**
PROJECT NAME:	**2012 - 1 Smart Metering**

Project Description

To create a conservation culture in Ontario, the Ministry of Energy and Infrastructure is committed to the installation of a "smart meter" in all Ontario homes and small businesses by the end of 2010. Pursuant to Ontario Regulation 427/06, EHM has commenced the mass deployment of smart meters for residential and small commercial customers where the metering of demand is not required. This project is for the completion of the Smart Metering deployment for 600 Volt metering installations which were not available in the market during the mass deployment of smart meters that was completed in 2010.

Justification

The 600 Volt meter was under development when the project began. Long delays in development, Measurement Canada approvals and issue resolution at the manufacturer delayed the availability of the meter until recently. Enersource has approximately 1,500 locations that require replacement of a mechanical 600 Volt meter with the new Elster 600V Smart Meter. It is expected that the deployment will be completed by the end of the first quarter of 2012.

Alternatives

Converting customer service for metering requirements is not economically feasible. Use of other 600V meters would cause compatibility issues with the smart meter network. Enersource is required to convert customers with smart meters onto Time of Use rates by the Ontario Energy Board by May 2012.

Results

1. This project will complete the requirement for Smart Metering of all Residential and Small General Service (<50kW).
2. Will allow for collection of meter data using the existing automated back office AMI application, eliminating the cost of manual reading for these meters.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 1,488		
Capital Costs funded by Others			
Total Capital Costs	**$ 1,488**		

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements - Internally Driven Investments**
INVESTMENT NAME:	**Rolling Stock**
BUSINESS UNIT #:	**C0584**
PROJECT NAME:	**2012/13/14 – Fleet**

Project Description

- The spending for this is required to meet vehicle and equipment fleet capital requirements based on replacement requirements, increased work program size and staff growth.
- EHM manages 192 fleet units which support the organization.
- Fleet vehicles must be maintained at an optimum level to comply with various regulations ex. Highway Traffic Act, CVOR regulations, etc. and to maintain productivity by minimizing downtime, travel time and taking advantage of technological improvement opportunities.

Justification

EHM requires a fleet of specialized vehicles to complete many daily activities including the construction and maintenance of the electrical distribution system and to allow for quick restoration of power due to electrical distribution system disturbances. . Degradation of fleet assets could jeopardize worker safety and negatively affect electrical distribution system performance and response to outages.

To effectively manage fleet assets EHM has adopted a Fleet Policy strategy whose goals are:

- to provide for the safe, reliable and efficient vehicles and equipment to meet the operational needs in consultation with the end user,
- Compliance with legislation and regulations,
- Compliance with accepted industry norms and practices,
- Cost effectiveness,
- Optimization of size of fleet - kept to minimum levels to ensure equipment is being used
- Standardization of equipment specifications,
- Environmental considerations such as fuel economy, exhaust emissions, and
- Disposal through reputable commercial vehicle and equipment resellers.

To achieve the goals outlined above, EHM maintains a multiple year capital plan. This plan is an essential tool for both short and long term budgeting and planning. This plan lists all the current vehicles and proposes the future replacement dates and costs, based on past experience and accepted industry standard vehicle lifecycles. Another of the long term goals of the capital plan is to smooth the annual capital expenditures.

Contributing to the proposed replacement date of individual vehicles are factors such as vehicle age, mileage, engine hours, operation costs, maintenance costs and general mechanical condition of the vehicle. Individual assessment of the vehicle is done by EHM's qualified mechanics when due to be replaced and sometimes adjustments may be made. Some vehicles may be retained because they are in better than average condition and some are replaced earlier due to being in poorer condition.

Vehicles are not always replaced "like for like". Prior to replacement of a vehicle, an assessment of the current fleet needs is made with the Supervisors to determine if an alternate vehicle type or size would be beneficial.

The proposed replacement ages for each vehicle class are outlined below.
Present replacement criteria are based on manufacturers' recommendations and repair history.

- Light vehicles are replaced after 3 - 5 years, or 170,000 km;
- Service trucks are replaced after 5 - 7 years or 200,000 km;
- Heavy equipment trucks are replaced after 10 – 12 years, or after 230,000 km and
- Work equipment is replaced on a condition based assessment.

Additional capital is also required to meet additional equipment requirements for staff growth, resulting from succession planning and work program increases.

Alternatives

Not proceeding or delaying this capital spending would lead to:

- lower-than-required fleet levels,
- increased maintenance costs,
- worker safety issues

Results

- Reduced repair and maintenance costs
- Decreased down time and increased fleet utilization
- Safer equipment for personnel to use
- Reduced environmental impacts.(alternative fuel considerations, compliance with new diesel standards)
- Increased service equipment diagnostics

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 1,834	$ 1,975	$ 1,975
Capital Costs funded by Others			
Total Capital Costs	**$ 1,834**	**$ 1,975**	**$ 1,975**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements - Internally Driven Investments**
INVESTMENT NAME:	**J.D. Edwards SYSTEM (JDE)**
BUSINESS UNIT #:	**C0588**
PROJECT NAME:	**2012/13 - 3 Budgeting and Planning**

Project Description

Currently budgets are prepared by extracting data from the financial systems and then working with Excel to update with the forecast amounts for the future years. All the calculations are done in many individual sheets including changes to manpower costs such as new hires, progressions etc. The finalized budget figures are then uploaded back to the financial system. This process is highly manual and involves all departments over an extended period of time. It is difficult to manage different versions of spreadsheets through multiple changes, approvals and iterations. The data needs to be linked together and much of it is confidential. Keeping track of all the spreadsheets and updating them can be very cumbersome. There is a continual risk that a person approving budget information may not be looking at the most current version. The budgets are difficult to compile and analyze.

This project is to implement the budgeting and planning module of the J.D.Edwards system. This module will allow the finance team and other departments involved in budgeting process to do scenario analysis and rapid reporting.

Justification

This will improve the timeliness of the budgeting process. Accuracy will be improved since there will no longer be multiple version of budgeting Excel spreadsheets being circulated. This will improve our ability to do scenario analysis and improve our ability to plan.

The automation of budgeting process will:

- allow the company to connect budgeting with other critical functions that drive company performance
- enable Enersource to create a single, collaborative budgeting process that can involve various departments and to facilitate communication throughout the organization
- make budgeting process dynamic by providing ability to run various scenarios and analyze impacts as conditions change and opportunities arise.
- provide for better monitoring and measuring results

Alternatives

Impact of Deferral

The impact of deferral is to continue with the inefficiencies of the processes currently in place.

Results

Improved efficiency and accuracy with the following tools:

1. Centralized budgeting portal for all required staff
2. Scenario analysis capability
3. Integration with the JDE financial system
4. Reporting and query tools

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013
Capital Costs funded by Board	$ 281	$422
Capital Costs funded by Others		
Total Capital Costs	**$ 281**	**$422**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements - Internally Driven Investments**
INVESTMENT NAME:	**J.D. Edwards System (JDE) and Engineering & Asset Systems**
BUSINESS UNIT #:	**C0588**
PROJECT NAME:	**2012/13/14 - 7 JDE – AM/FM Asset Management Application Integration, Phases 1, 2 and 3**

Project Description

Information pertaining to assets is housed in multiple systems and integration of these various systems will provide the tools to the organization for decision-making.

This project is to integrate the information about assets from multiple systems. These systems include information about purchasing, installation history, maintenance history, geographic location, connection to the distribution network and electrical load.

Additional software is required as well in order to help with the analysis of the overall asset base so that the optimal spending choices can be made.

With more information of the plant assets in the field available, such as model, age, location, manufacturer as well as failure statistics, inventory demand planning can be more accurately assessed. This will allow for the appropriate amount of inventory to be held in stock to facilitate maintenance activities. This phase of the project will require the integration of JDE and AM/FM.

Plant and equipment must be inspected every five years, and several programs are in place to ensure that this takes place. Information about the inspections is stored in the AM/FM/GIS, but a more automated method for capturing the data is needed. A more formalized approach to storing and retrieving the information is also required.

This project will be developed in conjunction with Engineering and Asset Systems (C0581).

Justification

The project will improve short- and long-range planning processes and provide direction for distribution system development, reliability improvements, asset inspection, maintenance and replacement programs, and the need for increases to overall system capacity.

Alternatives

The alternative to this project is to continue with our current methodology for system planning and maintenance. These are effective, but it is believed that improvements can be made.

Impact of Deferral

A short to medium delay should not have a significant impact other than postponing the benefits that are an anticipated result of the integration.

Results

The time and effort required for decision-making will be reduced and optimum budget planning can be done as more information is readily available. It is anticipated that costs per customer will come down. Optimal planning will contribute to a stable system, offering the best possible value. Proactive preparation for regulation changes will be possible.

Estimated Annual Expenditure ($ 1,000's)

COST TYPE	2012	2013	2014
Capital Costs funded by Board	$ 272	$ 750	$ 562
Capital Costs funded by Others			
Total Capital Costs	**$ 272**	**$ 750**	**$ 562**

EHM PROJECT BUSINESS CASE

INVESTMENT CATEGORY:	**Non-System Requirements - Internally Driven Investments**
INVESTMENT NAME:	**IT – Meter to Cash**
BUSINESS UNIT #:	**C0589**
PROJECT NAME:	**2014 – 1 CC&B Upgrade Phase 1**

Project Description

The Customer Care and Billing system (CC&B) is critical to billing, customer service, collections, and regulatory compliance. It must be upgraded on a periodic basis in order to secure a high level of reliability and take advantage of new features provided by the vendor under our maintenance agreement. To minimize risk we must ensure that we continue to use versions that are supported by the vendor.

Enersource' strategy is to perform major upgrades periodically that ensure software in use is vendor supported. By the end of 2014 the CC&B application will have been in service for 5 years and will be a minimum of 2 versions behind the most current release. Therefore an upgrade will be required in 2014.

The implementation is estimated to run through the majority of 2014. The budget includes $756K of internal and external development resources and $500K in software costs.

Justification

The CC&B application is continuously upgraded by its vendor, Oracle, to add features, functionality and maintain compatibility with operating systems and other industry standard tools and software that interface with it.

For major applications such as the CC&B, it is also important to stay reasonably current in order to secure support from the vendor. As new versions are introduced, vendors discontinue call support and bug fix/patches for older versions. Therefore companies using software where support has been discontinued are exposed to a wide array of risks from security to incompatibilities to unfixable program errors. By the end of 2014 the CC&B application will have been in service for 5 years and will be a minimum of 2 versions behind current release. See "Impact of Deferral" for further information on risks.

Alternatives

Delay the upgrade to future point (see "Impact of Deferral" below).
Replace with competitor product This would take years, millions of dollars of cost and include enormously higher risks

Impact of Deferral

If the upgrade is deferred for too long, the vendor will stop providing support and the system will start becoming incompatible with other products in the network.

By performing the upgrade we avoid considerable risk. Risks mitigated by the upgrade include but are not limited to;

- Discontinued CC&B software call and on-line support for trouble incidents (they discontinue support for older versions as new versions are introduced)
- Issues because CC&B software bug fix/patch corrections have been discontinued (they discontinue patch corrections once support for older versions is discontinued)
- Windows operating system and services compatibility issues
- Web Browser compatibility issues
- Security issues
- System performance issues
- Backup and fail-over systems related issues
- Issues with use of other dependent software and tools

Results

Staying on current versions of software increases the reliability of the applications and reduces the risk of incompatibilities and failures in the future.

Estimated Annual Expenditure ($ 1,000's)			
COST TYPE	**2012**	**2013**	**2014**
Capital Costs funded by Board			$1,265
Capital Costs funded by Others			
Total Capital Costs			**$1,265**

Green Energy Act Plan Capital Expenditures

As discussed in the Board's *Filing Requirements for Transmission and Distribution Applications* issued June 22, 2011, in Section 2.3.4, Green Energy Act Requirements, distributors filing cost of service rate applications for 2012 and subsequent rate years must file with the Board a Green Energy Act Plan ("GEA Plan") as part of such an application.

Enersource has prepared a Basic GEA Plan which is found at Exhibit 2 Tab 2 Schedule 3 Appendix 1. This has been prepared in accordance with the Board's EB-2009-0397 Filing Requirements of March 25, 2010.

Distributors are required to submit a letter of comment from the Ontario Power Authority ("OPA") as part of the GEA Plan. This is provided at Exhibit 2 Tab 2 Schedule 3 Appendix 2. The OPA has reviewed Enersource's GEA Plan and found it consistent with the OPA's information regarding renewable energy generation applications to date.

This GEA Plan provides information regarding the connection of renewable generation, and focuses on two main areas, namely:

1. An assessment of the distributor's current system; and
2. Planned development of the system to accommodate renewable generation connection[1].

[1] "OEB Filing Requirements EB-2009-0397", March 25, 2010, retrieved from http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Filing_Req_DistributionSystemPlans.pdf on April 03, 2012.

The GEA Plan may also include preliminary work for the development of a smart grid, if the distributor is seeking to recover smart grid related costs. Enersource is not seeking smart grid funding, therefore smart grid developments are not covered in this GEA Plan. Enersource continues to monitor advancing technologies and new market developments.

Conservation and demand management ("CDM") programs are not included in the GEA Plan as is defined in the OEB EB-2009-0397 Filing Requirements.

The GEA Plan identifies the renewable generation projects that have been connected to Enersource's distribution system and discusses constraints on the ability to connect renewable generation. As part of the requirements under the Distribution System Code ("DSC") requiring Enersource to connect generators to the system, Enersource has expended efforts to develop customer service processes for new generators that are simple, expedient and engaged from initial application through to the final commission process. In addition, Enersource has revised standards for safe operation while ensuring accurate metering and settlement by properly integrating generation data into internal systems. This effort is supported through existing internal staff.

As of the end of the first quarter of 2012, Enersource has connected a total of 85 MicroFIT installations totaling of 502.87 kW of generation capability and 12 FIT installations totaling 7350 kW of generation capability, as shown in Table 1 below.

Table 1: Applications Received and Projects Connected as of Q12012

	# Of Applications Received	# Of Projects Connected
MicroFIT (<=10kW)	640	85
FIT (>10kW)	429	12
TOTAL	**1069**	**97**

Capital expenditures to address renewable generation connections are identified in the GEA Plan and summarized in Table 2 below. These capital expenditures are incorporated into Enersource's annual capital planning and have been included in the proposed rate base in this Application. Note that these capital costs are included in the Asset Management Plan found at Exhibit 2 Tab 2 Schedule 2 Appendix 1.

Table 2: GEA Capital Expenditures by Enersource, 2011 to 2016 ($000s)

Cost Type	2011 (Actual)	2012	2013	2014	2015	2016
Capital Costs Funded By Enersource	197	133	183	219	256	293

Enersource does not propose to divide the costs of eligible renewable generation connection investments between Enersource customers and all Ontario ratepayers as per Regulation 330/09 and taking into account the Board's Report on the determination of direct benefits (EB-2009-0349).

Enersource is seeking approval of its GEA plan in this cost of service rate application.

Enersource

Green Energy Act Basic Plan 2012

Enersource
April 5th, 2012
Private and Confidential

1 Executive Summary

Enersource is a local energy distributor that services approximately 195,000 customers throughout the City of Mississauga and is licenced by the Ontario Energy Board. As part of the submission to fulfill the Ontario Energy Board Filing Requirements for the Conditions of Licence, Enersource has prepared a Basic Green Energy Act (GEA) Plan. The GEA Plan contains a description of the current undertakings to enable renewable generation, as well as future initiatives and planned expenditures to continue to allow for connection of new projects.

Enersource has connected a number of renewable generation installations under the Feed-In-Tariff (FIT) program. As of the end of the first quarter of 2012, Enersource has connected and settles a total of:

- 85 MicroFIT installations totaling of 502.87 kW of generation capability
- 12 FIT installations totaling 7350 kW of generation capability

Enersource has incorporated their FIT Program with existing Customer Engineering department. In addition to utilizing the existing resources within the department, other resources were added such as two co-op students, a Field Construction Inspector and a Service Engineering company.

Following the government's "Two-Year Review" of the FIT Program, the government has signaled continued commitment to the program. As a result, Enersource anticipates demand for the program to be steady and therefore will require future capital expenditures in order to continue to connect renewable generation projects as is required by the Ontario Energy Board Distribution System Code. Enersource has a series of projects planned involving system business of expansion and refurbishment, and will consider the impact in enabling renewable generation within the prioritization mix. There are also potential required investments for

system expansion to connect renewable generation that will come via the Offer-To-Connect process.

A number of constraints have been placed on the Enersource system by the upstream transmitter, Hydro One, that will limit the amount of renewable generation that can be connected. Enersource intends to continue its strong working relationship with its transmitter and will work with it to help resolve new issues as they arise.

2 Introduction and Background

Enersource is a progressive Local Distribution Company (LDC) and has been a proponent of renewable energy well before the Green Energy and Green Economy Act was implemented. Enersource's significant involvement with projects many years ago such as the interconnection of a large biogas generation facility at major landfill site and a solar photovoltaic installation on a sports stadium are some of the examples of Enersource's early adoption of embedded green energy generation. Since then, Enersource has helped enable numerous renewable energy projects to connect to the system.

In May of 2009, the Green Energy and Green Economy Act, 2009 (GEA) was formally passed into Ontario law. The Feed-In Tariff (FIT) Program is the cornerstone of the Act, and is North America's first comprehensive guaranteed pricing structure for renewable electricity production. The Ontario Power Authority (OPA) is responsible for implementing the program and offers stable prices under long-term contracts for energy generated from renewable sources, including:

- Solar photovoltaic
- On-shore and off-shore wind
- Biomass

- Biogas
- Landfill gas
- Waterpower

The Ontario Energy Board (OEB) Filing Requirements states that distributors filing a cost of service rate application must file with the Board a Green Energy Act Plan (GEA Plan) as part of the submission. The OEB Filing Requirements EB-2009-0397 specifies two types of GEA plans; the Basic GEA Plan and the Detailed GEA Plan. The Detailed GEA Plan is required only for those distributors who meet either of the two following circumstances:

1. The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:

    - Are more than $100,000 and exceed 3% of the distributor's distribution rate base; or
    - Exceed $5,000,000

2. The total capital costs of all a distributor's planned projects related to the connection of renewable and/or the development of a smart grid over five years:

    - Are more than $100,000 and exceed 6% of the distributor's distribution rate base; or
    - Exceed $10,000,000

Enersource does not meet either of the above thresholds for filing a Detailed GEA Plan; therefore a Basic GEA Plan has been prepared. The Basic GEA plan focuses on two main areas, namely:

1. Current assessment of the distributor's system

2. Planned development of the system to accommodate renewable generation connection[1]

The GEA Plan may also include preliminary work for the development of a smart grid, if the distributor is seeking to recover smart grid related costs. Enersource is not seeking smart grid funding, therefore smart grid developments are not covered in this GEA Plan. Enersource continues to monitor advancing technologies and new market developments.

This Enersource GEA Plan is based on current information and presents both a near-term and a short-term perspective of Enersource's plans for its distribution system with respect to accommodating new connections of renewable generation facilities.

3 Current Assessment

3.1 Distribution System

Enersource has traditionally distributed power from Hydro One transformer stations to its customers either directly from the subtransmission system or through its distribution system. With the implementation of the FIT Program, Enersource has now evolved into a multifaceted distributor of power from both Hydro One transformer stations and embedded generators within the Enersource system.

3.2 Renewable Generation Projects Connected

The Enersource service territory is mainly an urban setting with a mix of residential, industrial/commercial, and high-rise buildings. Presently, the main type of renewable

[1] "OEB Filing Requirements EB-2009-0397", March 25, 2010, retrieved from http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Filing_Req_DistributionSystemPlans.pdf on April 03, 2012.

generation found within Mississauga is photovoltaic from roof mounted solar panel installations. The majority of MicroFIT projects have been installed on the rooftops of residential customers, however there are a few commercial MicroFIT installations as well. There is also a large amount of industrial/commercial/warehouse facilities located in Mississauga, and these are primarily where the mid-size photovoltaic FIT systems have been connected.

There is also potential for several biogas and wind installations within Mississauga. Enersource has received a number of preliminary applications from landfill sites and water treatment plants exploring the possibility of installing mid-size biogas FIT systems. There has also been three wind MicroFIT applications received to date, however the characteristics of the service territory will likely not translate into a high demand for this type of project.

The table below provides a summary of the renewable energy projects connected as of the end of the first quarter of 2012. A complete listing of all connected projects in the Enersource system is contained in Appendix A. It should be noted that Conservation and Demand Management (CDM) programs are not included in this GEA Plan as is defined in the OEB Filing Requirements EB-2009-0397.

	Total Number of Projects Connected	Total kW of Projects Connected
MicroFIT (<=10kW)	85	502.87
FIT (>10kW)	12	7350
TOTAL	**97**	**7852.87**

Table 1 – MicroFIT & FIT Projects Connected as of End of 2012Q1

3.3 Constraints on Ability to Connect Renewable Generation

Although a significant number of projects have already been connected to the Enersource system, there are, however, a number of constraints that exist that will limit the amount of renewable generation facility connections. The upstream transmitter, Hydro One, has placed a number of restrictions to their transformer station feeders based on the thermal ratings and the short circuit capacity of the relevant equipment in accordance with limits set forth in the Transmission System Code (TSC). To determine if capacity is available on a given Hydro One transformer station feeder, the Hydro One "Station & Feeder Capacity Calculator"[2] is used.

In addition to this, Hydro One has also imposed a limit on the amount of generation allowed per feeder. The threshold is specified to be 10% of maximum peak load for "M" class feeders and 7% of maximum peak load for "F" class feeders. Hydro One has requested that all LDCs comply with this standard[3] and Enersource has committed to doing so. A complete listing of all Enersource feeders with their respective available generation capacity can be found in Appendix B.

3.4 Expenditures Related to Renewable Generation Connections

As a part of the requirements of the OEB's Distribution System Code (DSC), LDCs are required to connect generators to their systems. In order for Enersource to comply, expenditures are required in a number of key areas to accommodate the FIT Program. To date, Enersource has focused on:

- Developing a customer service process for new generators that is simple, expedient and is engaged from initial application activities through to final commissioning process
- Developing new standards for safe operation and compliance of generator connections

[2] "Station & Feeder Capacity Calculator", retrieved from http://www.hydroone.com/Generators/Pages/StationCapacityCalculator.aspx on April 03, 2012
[3] "Screening & Reporting Requirements" Hydro One webinar, presented on Tuesday, August 30, 2011.

- Ensuring meter requirements are available, functioning properly and compliant with regulation
- Integrating new generators into IOM, AM/FM/GIS and CC&B systems to properly document, operate, monitor, settle and provide quality assurance

During the summer of 2011, Enersource underwent a significant reorganization in order to more effectively manage the FIT Program. The incorporation of the FIT Program into the existing Customer Engineering department allows for closer coordination with customers and provides a single point of contact for all customer connection needs. It has allowed Enersource to be more effective when offering solutions when initial applications are rejected due to capacity constraints. Possible solutions include proposals such as service upgrades, alternate connections, or system expansions.

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 to assist with processing FIT Program applications and documentation (16-month term Engineering students were selected due to the risk and uncertainty of the program demand)
- A contracted independent Professional Engineer Field Inspector with relevant medium-voltage customer relation experience to be used as needed
- A contracted Services Engineering firm to perform Connection Impact Assessments on behalf of Enersource

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.

4 Planned Development to Accommodate Renewable Generation

4.1 Anticipated Renewable Generation Connections

In March of 2012, the Ontario government released its "Two-Year Review" of the FIT Program. Although the review recommended reductions in some areas of the FIT and MicroFIT pricing structure, the prices are still generally regarded to be favourable. This has signaled the Ontario Government's continued commitment to the program in order to achieve its economic and environmental objectives. Enersource anticipates that the FIT Program will likely continue throughout the next few years as it approaches the target of 10,700 MWs of connected renewable generation.[4]

The table below presents the total number of FIT and MicroFIT applications received by Enersource as of the end of the first quarter of 2012. These figures include all projects listed on the OPA's FIT Application Management Environment (FAME) and MicroFIT LDC Admin web portals, as well as all projects that requested initial capacity checks to be performed by Enersource, which may or may not be registered with the OPA.

	# Of Applications Received	# Of Projects Connected
MicroFIT (<=10kW)	640	85
FIT (>10kW)	429	12
TOTAL	**1069**	**97**

Table 2 – Applications Received & Projects Connected as of End of 2012Q1

The supporting documentation used to develop the Enersource Asset Management Plan (AMP) includes a forecast of the total number of renewable generation projected to be connected.

[4] "Ontario's Feed-In-Tariff Program – Two Year Review Report", retrieved from http://www.energy.gov.on.ca/docs/en/FIT-Review-Report.pdf on April 03, 2012.

The estimates are shown in the table below. It should be noted during the first quarter of 2012, Enersource connected an unusually large number MicroFIT projects. This was driven by the fact that many projects were approaching their one year contract expiration date.

	ACTUALS			FORECASTED				
	2010	**2011**	**2012Q1**	**2012**	**2013**	**2014**	**2015**	**2016**
MicroFIT (<=10kW)	19	32	34	35	50	60	70	80
FIT (>10kW)	3	7	0	20	25	30	35	40
TOTAL	**22**	**39**	**34**	**55**	**75**	**90**	**105**	**120**

Table 3 – Forecasted Renewable Energy Connections by Year

4.2 Infrastructure Projects and Activities

4.2.1 Renewable Enabling Improvements

A Renewable Enabling Improvement (REI) is *a modification or addition to the main distribution system that is made to enable the main distribution system to accommodate generation from renewable energy generation facilities and that consists of one or more of the following:*

- *Modifications or additions to allow for and accommodate two-way electrical flow, as opposed to radial flow;*
- *Modifications to, or the addition of, electrical protection equipment;*
- *Modifications to, or the addition of, voltage regulating equipment; or*
- *The provision of protection against islanding (transfer trip equivalent)*[5]

Enersource's assessment of the distribution system identifies a number of capital investment improvements planned in the next 5 years that will assist in enabling renewable energy

[5] "OEB Guidelines G-2009-0087" retrieved from http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2009-0087/Dx_System_Planning_Guidelines_20090616.pdf on April 03, 2012.

projects. The associated costs are already included in the Enersource capital plan, therefore no further incremental funding is required. The list of projects includes:

- Substation equipment and protection; as new substations are constructed and existing facilities refurbished, provisions will be made to install digital relaying which will have the ability to provide reverse power flow protection. Furthermore, the ratings for the new substation equipment will be specified to withstand increased short circuit levels that may be present in the future due to new renewable generation connections.
- Underground system rebuilds; replacement of the underground primary distribution system in certain areas of Mississauga will involve replacing aging 37.5 kVA padmounted transformers with Enersource standard 100 kVA padmounted transformers. This may increase the amount of transformation available in these areas depending on the optimization of the number of transformers used, which may result in increased capacity available for renewable generation to be connected.
- Overhead system expansion; additional circuits will be installed that will provide more opportunity for renewable generation connections by providing increased access to Hydro One transformer stations and Enersource substations that have capacity available for generation connections as required.

4.2.2 Offer-To-Connects For System Expansion

A System Expansion is defined as *a modification or addition to the main distribution system in response to one or more requests for one or more additional customer connections that otherwise could not be made, for example, by increasing the length of the main distribution system, and includes the modification or addition to the main distribution system identified in*

section 3.2.30 (of the DSC) but in respect of a renewable energy generation facility excludes a renewable enabling improvement[6].

Due to various constraints with the Hydro One transmission network, a number of Hydro One transformer stations do not have capacity to connect renewable energy generation. A renewable energy generator customer whose connection would be to a transformer station with no capacity can elect to explore alternate options to expand the subtransmission and distribution network in order to connect their project to a transformer station that does have capacity.

The Enersource Customer Engineering team evaluates the different options and associated costs to determine the most economic solution. The selected option is then reviewed through the Offer-To-Connect process. In 2011, Enersource received two requests from customers to provide Offer-To-Connects. A brief summary of both Offer-To-Connects is shown in the table below. To date, neither customer has accepted the Offer-To-Connect.

Address	Proposed Size	Scope Of Expansion	Enersource Contribution	Customer Contribution
Project A	1500 kW	2 concrete poles, load interrupter, 1000m of primary overhead conductoring	$135,000	$222,960
Project B	500 kW	170m of concrete encased ductbank, primary underground cabling and connections	$45,000	$233,248

Table 4 – List of Offer-To-Connects Presented as of End of 2012Q1

[6] "OEB Distribution System Code", October 1, 2011, retrieved from http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf on April 03, 2012.

The Enersource contribution for each Offer-To-Connect project is required as per the DSC under Section 3.2.5B, "a distributor shall not charge any of the requesting generators to construct the expansion" up to $90,000 per MW of generation. The capital cost of the project over and above the $90,000 per MW of generation is funded by the customer. Although no Offer-To-Connects have been accepted to date, Enersource does anticipate that there will likely be 1-2 projects per year that will require a capital contribution by Enersource.

Furthermore, when an Offer-To-Connect is accepted by a customer, there will likely be a requirement for contribution from the customer for the system expansion. The forecasted customer contributions for the next 5 years is shown in the table below.

Cost Type	2011 (Actual)	2012	2013	2014	2015	2016
Capital Costs Funded By Others (Customers)	$0	$107,000	$133,000	$160,000	$187,000	$213,000

Table 5 – Forecasted Capital Contribution by Others (Customers)[7]

4.2.3 Continuing Capital Expenditures

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.

[7] Enersource Asset Management Plan, April 2012.

Cost Type	2011 (Actual)	2012	2013	2014	2015	2016
Capital Costs Funded By Enersource	$197,413	$133,000	$183,000	$219,000	$256,000	$293,000

Table 6 – Forecasted Capital Expenditures by Enersource[8]

4.3 Direct Benefits to Customers

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.

4.4 Prioritization Method

Enersource will continue to consider enabling renewable generation while undertaking expansion and refurbishment projects. Prioritization of REI projects and Offer-To-Connect expansions will be based on a combination of the following factors:

- Areas/stations where work is already planned
- Replacement of aging infrastructure
- Areas/stations where there is a high concentration of proposed FIT/MicroFIT projects
- Areas/stations that are capacity constrained
- In-service dates of Offer-To-Connect projects

4.5 Consultation with Transmitter

Enersource has a strong working relationship with its upstream transmitter, Hydro One, and has consulted with them on a series of issues raised by the FIT Program. One discussion initiated by

[8] Ibid.

Enersource was with respect to the capital upgrades that would be required to enable renewable generation at capacity constrained transformer stations. This included estimates in order to upgrade equipment to a higher rating or to install transformers with a higher impedance to reduce short circuit levels present at the station. This information was then shared by Enersource with its customers in order to identify the feasibility of the customer's projects.

Another area that Enersource has requested further clarification by Hydro One is a secondary review of the restrictions placed on capacity constrained transformer stations. This information was also shared with Enersource's renewable generation customers to help them understand the challenges that exist in the system. This demonstrates Enersource's commitment to servicing its customers and enabling renewable generation.

Enersource intends to continue to maintain the strong working relationship it has with Hydro One by working collaboratively through these issues as well as new issues as they arise.

4.6 Letter of Comment from OPA

To be attached in Appendix C.

5 Conclusion

This Basic GEA Plan outlines effective processes and sound investment plans that have been developed by Enersource in order to manage the FIT Program. Enersource has successfully connected many FIT and MicroFIT projects to date, and the outlook for the continuation of the program remains positive. This will require continued expenditures in order to meet the demands of renewable energy project connections. Enersource is looking forward to working with its customers on renewable energy projects and contributing to the success of the GEA.

Appendix A – MicroFIT and FIT Projects Connected up to End of 2012Q1

FIT Projects

Type Of Renewable Generation	Size (kW)	Connection Date
Solar Photovoltaic	100	11-Mar-11
Solar Photovoltaic	250	19-May-11
Solar Photovoltaic	215	18-May-11
Solar Photovoltaic	149	10-Mar-11

Solar Photovoltaic	250	20-May-11
Solar Photovoltaic	30	2-Sep-11
Solar Photovoltaic	91	23-Jun-11
Solar Photovoltaic	135	7-Sep-11
Solar Photovoltaic	355	24-Oct-11
Solar Photovoltaic	250	12-Sep-11
Solar Photovoltaic	25	7-Jul-07
Biogas	5500	1-Nov-05
TOTAL	**7350**	

There is also 1 additional project that is connected under the NET Metering Program:

Type Of Renewable Generation	Size (kW)	Connection Date
Wind	50	1-Jan-10

MicroFIT Projects

Type Of Renewable Generation	Size (kW)	Connection Date
Solar Photovoltaic	5.00	3/4/2010
Solar Photovoltaic	1.90	3/5/2010

Solar Photovoltaic	1.70	3/5/2010
Solar Photovoltaic	5.40	3/5/2010
Solar Photovoltaic	3.00	3/15/2010
Solar Photovoltaic	1.14	4/20/2010
Solar Photovoltaic	3.00	4/26/2010
Solar Photovoltaic	2.55	6/28/2010
Solar Photovoltaic	4.94	9/28/2010
Solar Photovoltaic	1.90	10/13/2010
Solar Photovoltaic	10.00	10/13/2010
Solar Photovoltaic	4.00	10/14/2010
Solar Photovoltaic	1.90	11/4/2010
Solar Photovoltaic	3.80	11/24/2010
Solar Photovoltaic	10.00	11/26/2010
Solar Photovoltaic	4.60	11/29/2010
Solar Photovoltaic	5.00	11/29/2010
Solar Photovoltaic	1.28	12/21/2010
Solar Photovoltaic	7.40	12/30/2010
Solar Photovoltaic	2.66	1/4/2011
Solar Photovoltaic	10.00	1/5/2011
Solar Photovoltaic	9.72	3/8/2011
Solar Photovoltaic	8.00	4/15/2011
Solar Photovoltaic	2.09	4/27/2011
Solar Photovoltaic	9.90	5/29/2011
Solar Photovoltaic	7.00	6/10/2011
Solar Photovoltaic	8.93	7/7/2011
Solar Photovoltaic	2.28	7/7/2011
Type Of Renewable Generation	**Size (kW)**	**Connection Date**
Solar Photovoltaic	3.70	7/12/2011

Solar Photovoltaic	3.42	7/22/2011
Solar Photovoltaic	10.00	7/26/2011
Solar Photovoltaic	1.43	7/29/2011
Solar Photovoltaic	8.55	8/12/2011
Solar Photovoltaic	3.42	8/27/2011
Solar Photovoltaic	9.72	9/27/2011
Solar Photovoltaic	2.96	9/27/2011
Solar Photovoltaic	5.00	9/27/2011
Solar Photovoltaic	5.52	10/4/2011
Solar Photovoltaic	9.00	10/5/2011
Solar Photovoltaic	5.98	10/27/2011
Solar Photovoltaic	5.00	10/27/2011
Solar Photovoltaic	6.00	11/9/2011
Solar Photovoltaic	7.74	11/11/2011
Solar Photovoltaic	5.59	11/15/2011
Solar Photovoltaic	5.00	11/28/2011
Solar Photovoltaic	5.00	11/29/2011
Solar Photovoltaic	1.94	12/2/2011
Solar Photovoltaic	1.71	12/2/2011
Solar Photovoltaic	5.13	12/13/2011
Solar Photovoltaic	10.00	12/15/2011
Solar Photovoltaic	10.00	12/19/2011
Solar Photovoltaic	2.47	1/7/2012
Solar Photovoltaic	4.95	1/14/2012
Solar Photovoltaic	6.45	1/15/2012
Solar Photovoltaic	10.00	1/16/2012
Solar Photovoltaic	7.59	1/16/2012
Solar Photovoltaic	5.00	1/18/2012

Solar Photovoltaic	10.00	1/23/2012
Type Of Renewable Generation	**Size (kW)**	**Connection Date**
Solar Photovoltaic	10.00	1/23/2012
Solar Photovoltaic	10.00	2/3/2012
Solar Photovoltaic	10.00	2/3/2012
Solar Photovoltaic	5.59	2/8/2012
Solar Photovoltaic	8.17	2/8/2012
Solar Photovoltaic	10.00	2/10/2012
Solar Photovoltaic	7.29	3/3/2012
Solar Photovoltaic	10.00	3/5/2012
Solar Photovoltaic	9.12	3/6/2012
Solar Photovoltaic	4.20	3/12/2012
Solar Photovoltaic	3.00	3/15/2012
Solar Photovoltaic	2.90	3/15/2012
Solar Photovoltaic	6.00	3/15/2012
Solar Photovoltaic	4.05	3/16/2012
Solar Photovoltaic	10.00	3/21/2012
Solar Photovoltaic	10.00	3/21/2012
Solar Photovoltaic	5.85	3/21/2012
Solar Photovoltaic	10.00	3/22/2012
Solar Photovoltaic	5.85	3/27/2012
Solar Photovoltaic	2.93	3/28/2012
Solar Photovoltaic	2.48	3/29/2012
Solar Photovoltaic	2.70	3/30/2012
Solar Photovoltaic	9.00	3/30/2012
Solar Photovoltaic	6.00	3/30/2012
Solar Photovoltaic	9.00	3/30/2012
Solar Photovoltaic	6.00	3/30/2012

Solar Photovoltaic	5.40	3/30/2012
TOTAL	**502.87**	

Appendix B – Available Generation Capacity by Feeder

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
1F1	4.16	71
1F2	4.16	152
1F3	4.16	141
1F4	4.16	80
1F5	4.16	177
1F6	4.16	134
2F1	4.16	0
2F2	4.16	0
2F3	4.16	0
2F4	4.16	186
3F1	4.16	0
3F2	4.16	188
3F3	4.16	146
3F4	4.16	146
3F5	4.16	111
3F6	4.16	154
4F1	4.16	147
4F2	4.16	143
4F3	4.16	149
4F4	4.16	177
4F5	4.16	152
4F6	4.16	0
5F1	4.16	126
5F2	4.16	81
5F3	4.16	70
5F4	4.16	92
7F1	4.16	131
7F2	4.16	61
7F3	4.16	128
7F4	4.16	223
8F1	4.16	131
8F2	4.16	130
8F3	4.16	172

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
8F4	4.16	88
8F5	4.16	126
8F6	4.16	94
9F1	4.16	141
9F2	4.16	134
9F3	4.16	180
9F4	4.16	178
9F5	4.16	147
11F1	4.16	91
11F2	4.16	98
11F3	4.16	103
11F4	4.16	111
11F5	4.16	61
12F1	4.16	174
12F2	4.16	153
12F3	4.16	179
12F4	4.16	183
12F5	4.16	179
22F1	4.16	86
22F2	4.16	127
22F3	4.16	225
22F4	4.16	114
23F1	4.16	85
23F2	4.16	100
23F3	4.16	122
25F1	4.16	83
25F2	4.16	192
25F3	4.16	100
26F1	4.16	180
26F2	4.16	101
26F3	4.16	134
29F1	4.16	42
29F2	4.16	155
29F3	4.16	93
35F1	4.16	138
35F2	4.16	133
35F3	4.16	77
35F4	4.16	0
36F1	4.16	51
36F2	4.16	58
36F3	4.16	64
36F4	4.16	128
40F1	4.16	158

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
40F2	4.16	167
40F3	4.16	161
41F1	4.16	86
41F2	4.16	80
41F3	4.16	106
41F4	4.16	146
42F1	4.16	264
42F2	4.16	82
42F3	4.16	122
65F1	4.16	0
65F2	4.16	71
65F3	4.16	196
66F1	4.16	58
66F2	4.16	142
66F3	4.16	32
66F4	4.16	158
67F1	4.16	23
67F2	4.16	149
67F3	4.16	140
67F4	4.16	118
78F1	4.16	200
78F2	4.16	198
78F3	4.16	0
78F4	4.16	132
78F5	4.16	35
79F1	4.16	172
79F2	4.16	120
79F3	4.16	202
13F1	13.8	755
13F2	13.8	768
13F3	13.8	302
13F4	13.8	550
13F5	13.8	469
13F6	13.8	491
14F1	13.8	132
14F2	13.8	295
14F3	13.8	532
14F4	13.8	298
14F5	13.8	369
14F6	13.8	260
15F1	13.8	187
15F2	13.8	309
15F3	13.8	0

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
15F4	13.8	333
15F5	13.8	359
17F1	13.8	592
17F2	13.8	410
17F3	13.8	544
17F4	13.8	438
19F1	13.8	336
19F2	13.8	652
19F3	13.8	0
19F4	13.8	331
19F5	13.8	346
20F1	13.8	557
20F2	13.8	504
20F3	13.8	422
20F4	13.8	802
20F5	13.8	665
20F6	13.8	760
21F1	13.8	316
21F2	13.8	487
21F3	13.8	485
21F4	13.8	439
21F5	13.8	98
21F6	13.8	370
21F7	13.8	738
21F8	13.8	609
24F1	13.8	166
24F2	13.8	528
24F3	13.8	315
24F4	13.8	521
24F5	13.8	295
24F6	13.8	114
27F1	13.8	748
27F2	13.8	673
27F3	13.8	375
27F4	13.8	339
27F5	13.8	417
27F6	13.8	299
27F7	13.8	0
28F1	13.8	673
28F2	13.8	411
28F3	13.8	261
28F4	13.8	451
28F5	13.8	328

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
28F6	13.8	532
30F1	13.8	532
30F2	13.8	66
30F3	13.8	487
30F4	13.8	406
30F5	13.8	267
30F6	13.8	543
30F7	13.8	620
31F1	13.8	379
31F2	13.8	329
31F3	13.8	336
31F4	13.8	855
34F1	13.8	542
34F2	13.8	431
34F3	13.8	287
37F1	13.8	728
37F2	13.8	418
37F3	13.8	711
37F4	13.8	471
37F5	13.8	363
37F6	13.8	419
38F1	13.8	261
38F2	13.8	166
38F3	13.8	569
38F4	13.8	715
38F5	13.8	377
38F6	13.8	601
39F1	13.8	620
39F2	13.8	189
39F3	13.8	500
39F4	13.8	671
43F1	13.8	497
43F2	13.8	740
43F3	13.8	683
43F4	13.8	432
43F5	13.8	606
43F6	13.8	562
45F1	13.8	399
45F2	13.8	455
45F3	13.8	467
45F4	13.8	250
45F5	13.8	584
45F6	13.8	383

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
47F1	13.8	172
47F2	13.8	267
47F3	13.8	691
47F4	13.8	354
47F5	13.8	161
47F6	13.8	570
48F1	13.8	350
48F2	13.8	542
48F3	13.8	91
48F4	13.8	481
48F5	13.8	320
48F6	13.8	85
49F1	13.8	514
49F2	13.8	645
49F3	13.8	528
49F4	13.8	674
49F5	13.8	601
49F6	13.8	579
50F1	13.8	576
50F2	13.8	539
50F3	13.8	628
50F4	13.8	577
52F1	13.8	662
52F2	13.8	661
52F3	13.8	351
52F4	13.8	513
52F5	13.8	499
52F6	13.8	408
54F1	13.8	810
54F2	13.8	289
54F3	13.8	612
54F4	13.8	764
54F5	13.8	464
54F6	13.8	672
57F1	13.8	631
57F2	13.8	643
57F3	13.8	282
57F4	13.8	269
58F1	13.8	540
58F2	13.8	680
58F3	13.8	199
58F4	13.8	382
59F1	13.8	484

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
59F2	13.8	574
59F3	13.8	420
59F4	13.8	530
60F1	13.8	272
60F2	13.8	340
60F3	13.8	720
60F4	13.8	498
60F5	13.8	352
60F6	13.8	656
60F7	13.8	423
60F8	13.8	298
61F1	13.8	0
61F2	13.8	343
61F3	13.8	494
61F4	13.8	360
68F1	13.8	697
68F2	13.8	570
68F3	13.8	0
68F4	13.8	278
68F5	13.8	573
68F6	13.8	119
68F7	13.8	841
69F1	13.8	356
69F2	13.8	298
69F3	13.8	432
69F4	13.8	517
71F1	13.8	500
71F2	13.8	391
71F3	13.8	552
71F4	13.8	617
82F1	13.8	507
82F2	13.8	442
82F3	13.8	368
82F4	13.8	297
82F5	13.8	491
82F6	13.8	144
83F1	13.8	63
83F2	13.8	388
83F3	13.8	728
83F4	13.8	683
83F5	13.8	667
83F6	13.8	329
83F7	13.8	457

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
84F1	13.8	633
84F2	13.8	619
84F3	13.8	625
84F4	13.8	310
85F1	13.8	165
85F2	13.8	264
85F3	13.8	548
85F4	13.8	231
85F5	13.8	151
85F6	13.8	0
85F7	13.8	535
85F8	13.8	354
88F1	13.8	139
88F2	13.8	564
88F3	13.8	537
88F4	13.8	418
88F5	13.8	203
88F6	13.8	301
89F1	13.8	730
89F2	13.8	724
89F3	13.8	548
89F4	13.8	394
89F5	13.8	666
89F6	13.8	771
90F1	13.8	303
90F2	13.8	107
90F3	13.8	565
90F4	13.8	23
90F5	13.8	22
90F6	13.8	202
90F7	13.8	126
90F8	13.8	125
6F1	27.6	1227
6F2	27.6	0
6F4	27.6	1049
6F5	27.6	1004
22M45	27.6	2246
22M46	27.6	2692
22M47	27.6	2206
22M48	27.6	2281
46M09	27.6	0*
46M10	27.6	0*
46M11	27.6	0*

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
46M12	27.6	0*
46M13	27.6	0*
46M14	27.6	0*
46M17	27.6	1535
46M18	27.6	1379
46M19	27.6	1543
46M20	27.6	844
46M21	27.6	1001
46M22	27.6	1136
67M01	27.6	1794
67M02	27.6	0*
67M03	27.6	2263
67M04	27.6	1892
67M05	27.6	1091
67M06	27.6	1970
67M07	27.6	925
67M08	27.6	1058
67M09	27.6	0*
67M10	27.6	1675
88M04	27.6	0*
88M05	27.6	0*
88M07	27.6	0*
88M47	27.6	1804
74M01	27.6	0*
74M07	27.6	2211
74M08	27.6	2026
74M09	27.6	1796
74M11	27.6	1896
74M12	27.6	2260
C5M31	27.6	2306
C5M32	27.6	2543
C5M33	27.6	3043
C5M34	27.6	1096
C5M35	27.6	1688
C5M36	27.6	2431
C5M37	27.6	0*
C5M38	27.6	1793
C5M39	27.6	1580
C5M40	27.6	2366
C5M41	27.6	3549
C5M42	27.6	2202
135M1	27.6	0*
135M2	27.6	0*

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
135M3	27.6	0*
135M4	27.6	0*
135M5	27.6	0*
135M6	27.6	0*
135M7	27.6	0*
135M8	27.6	0*
135M9	27.6	0*
135M10	27.6	0*
74M23	44.0	0*
74M24	44.0	0*
74M25	44.0	0*
74M29	44.0	0*
74M45	44.0	0*
74M46	44.0	0*
74M50	44.0	0*
C5M01	44.0	3481
C5M02	44.0	3744
C5M03	44.0	3412
C5M04	44.0	3109
C5M05	44.0	2429
C5M06	44.0	3675
C5M07	44.0	2978
C5M08	44.0	3778
C5M23	44.0	3658
C5M24	44.0	2605
C5M25	44.0	2020
C5M26	44.0	2356
C5M27	44.0	3368
C5M28	44.0	3237
C5M29	44.0	4111
C5M30	44.0	3105
83M01	44.0	3288
83M02	44.0	2547
83M03	44.0	7001
83M04	44.0	3539
83M05	44.0	4074
83M06	44.0	3160
83M07	44.0	2849
83M08	44.0	1504
83M23	44.0	3289
83M24	44.0	3125
83M25	44.0	2683
83M26	44.0	2591

Enersource Feeder ID	Voltage (kV)	Generation Allowed (kW)
83M27	44.0	1643
83M28	44.0	3044
83M29	44.0	2547
83M30	44.0	4277
R3107M03	44.0	2843
R3107M04	44.0	3969
R3107M05	44.0	3089
R3107M06	44.0	3927
R3107M07	44.0	4005
R3107M08	44.0	4228
D6M12	44.0	0*
D6M13	44.0	2473
D6M14	44.0	1695
240M1	44.0	3739
240M2	44.0	3396
240M3	44.0	4204
240M4	44.0	4016

*Denotes feeders that are Hydro One capacity constrained.

OPA Letter of Comment:

Enersource

Basic Green Energy Act Plan

April 16, 2012

ONTARIO POWER AUTHORITY

1

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Enersource Hydro Mississauga Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Enersource Hydro Mississauga Inc. ("Enersource") dated April 5, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

Table 2 – *Applications Received and Projects Connected as of End of 2012Q1* on page 7 of Enersouce's Plan indicates that as of Q1 of 2012 Enersource received a total of 429 FIT and a total of 640 microFIT applications (Stage 1 applications). Of these, 12 FIT projects representing 7.35 MW of capacity, and 85 microFIT projects totalling just over 0.5 MW have been connected to the Enersource distribution system. Based on conversations with Enersource, the OPA understands that the total number of Stage 1 applications also includes the total number of initial capacity request applications.

To date, the OPA has received and offered contracts to 123 FIT applications totalling 20.73 MW within the Enersource service territory, of which 109 FIT applications totalling 18.27 MW still remain active. Additionally, as of April 13, 2012, the OPA has processed 356 still active microFIT applications totalling 2.88 MW of capacity, of which 282 microFIT applications totalling 2.23 MW have been offered a contract. These numbers closely align with the Stage 2 numbers on Table 2 of Enersource's Plan which indicates that the OPA received 388 microFIT applications and 123 FIT applications. The small disparity in the microFIT numbers is likely a result of when the data was collected.

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The OPA also clarified with Enersource that the Stage 2 numbers in Table 2 represent the number of active applications processed by the OPA, and do not include incomplete applications, or those which were later terminated.

Upstream Transmission Constraints

There are no currently known upstream transmission constraints applicable to Enersource's service territory.

Economic Connection Test

The OPA received a directive dated April 5, 2010 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that Enersource's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Enersource's Basic GEA Plan.

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Harmonized Sales Tax ("HST")

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax ("GST") were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010.

All capital expenditures on or after July 1, 2010 exclude PST amounts that otherwise would have been embedded in the capital costs prior to this date.

According to the Board's *Accounting Procedures Handbook Frequently Asked Questions December 2010* ("APH-FAQ December 2010)[1], Enersource has calculated its savings as a result of the transition to HST using 2009 as a proxy to estimate the savings from July 1, 2010 to the distributor's next cost of service application. Please refer to Exhibit 9 Tab 1 Schedule 1 for further details.

[1] APH-FAQ December 2010, at pages 3-4.

Administration Office and Operations Centre

Introduction and Overview

Enersource has included approximately $24,000 of capital expenditures in rate base in the 2013 Test Year and an additional $1,000 in the 2014 ICR Year, related to facilities. The purpose of this exhibit is to discuss the decision-making process undertaken by Enersource that has resulted in the purchase of a building at 2185 Derry Road West ("2185 Derry Road" or "Derry Road") that will become the new administration and corporate head office for Enersource, to be occupied in September, 2012. The existing property at 3240 Mavis Road ("Mavis Road") will be reconfigured back to its original purpose as an operations centre.

History of Current Enersource Office Property

The Mavis Road property consists of approximately 70,000 square feet of office area and 60,000 square feet of industrial utilization. The lot size is 10.22 acres and includes a section of exterior yard storage. The entire property accommodates all Enersource employees.

The Mavis Road facility was constructed in a series of expansions and renovations. The original building was constructed almost fifty years ago, in 1963, as a warehouse and maintenance facility, with a minor office component fronting on Mavis Road.

Figure 1 provides a picture of the Mavis Road property and its development phases. The original industrial warehouse section is shown in green and the original two-story office section is shown in yellow.

Figure 1: Overhead View of the Mavis Road Facility

A three-story office tower was added in 1979 on the north side of the original building structure. This is shown in light blue on Figure 1.

This tower addition was designed as a connected but independent structure. The floor levels of the 1963 and 1979 structures are not contiguous, and thus, must be accessed via internal fire exit stairs.

All Enersource employees were consolidated in 1980 at Mavis Road and have operated at this location ever since.

A further addition to the Mavis Road facility was built in 1991 at the south façade of the original structure. This is shown in fuchsia in Figure 1.

This addition was also designed as independent of the original structure, and was similarly connected, with access exclusively via stairs. It provided space to house the new Control Room operations centre.

The current building does not have an elevator or compliance with the built environment standard requirements of the current *Accessibility for Ontarians with Disabilities Act* ("AODA").

In conjunction with the two major expansions described above, numerous renovations have converted warehouse and maintenance facilities to office use to accommodate office staff needs. Following the 1991 expansion, continued growth and expansion has resulted in ongoing renovations to accommodate office staff and business functionality.

Since 1986, the number of inside workers requiring office space at the Mavis Road facility has steadily grown from 153 to 236 employees, an increase of 54%, to meet the growth and incremental needs of Enersource customers and to comply with legislative and regulatory requirements. During that period, the population of Mississauga has grown by 91% and the number of customers served by Enersource has grown by approximately 95,000 customers, or 96%.

Analysis of Current Facilities

Enersource has struggled to accommodate the growth in the company and the number of employees and stakeholders using the Mavis Road facility and property. A number of these issues are identified and described in the following sections.

Multiple Congestion Issues:

- Enersource had constrained its administrative and operations personnel into the existing Mavis Road facility. The building's infrastructure systems were not designed to support the current density of occupancy thus is incapable of meeting the requirements of a modern building facility;

- As mentioned above, since 1986 there has been a 54% increase in the number of Enersource personnel requiring office space at Mavis Road. This does not include contractors that may also require office space and meeting rooms for extended periods;

- Meeting rooms have been eliminated and converted to staff office accommodations;

- Physical limitations in the building have resulted in inconsistent, compromised, and reduced office sizes and ergonomic accommodations;

- Warehouse and maintenance areas have been compromised and constrained to allow for office staff accommodation;

- Vehicular traffic and parking lot utilization is similarly beyond the capacity of the site. Customer and visitor parking are constrained to the point of unavailability. Employee parking has encroached on exterior storage yards and truck traffic traverses staff parking areas. At times employee parking overflows to parking in non-designated areas. The risk of vehicular collisions has risen to unacceptable levels; and

- Over-crowding of the Mavis Road property has required the leasing of another lot facility farther north, to accommodate truck movements, parking and a pole storage yard. This solution solved the problem on an

interim basis. This issue was identified in Enersource's 2008 COS rate application, including plans to buy the land adjacent to the south of 3240 Mavis Road. This land never came available for sale.

Workplace Environment Issues:

- 23% of inside employees work in the basement level where natural light and adequate ventilation are not available;

- Levels of electromagnetic fields in the building have created health and safety concerns for employees who are now exposed. As office areas have expanded, and work and storage areas have been converted into office areas, personnel have encroached unsuitable areas that are not sustainable. The cause is due to the unacceptably high building occupancy. Enersource has retained the assistance of external expertise to identify and address areas of concern. This again constrains the usefulness of the converted areas within the building;

- Air quality is compromised due to the over-capacity of staff relative to the capabilities of the air systems in the building. As a result, densely-occupied areas are failing to meet legislative requirements for fresh air supply and temperature control. Enersource has retained the assistance of external expertise to identify and address areas of concern. The air quality report by T. Harris Environmental Management Inc. ("Harris") is provided as Exhibit 2 Tab 2 Schedule 5 Appendix 1.

Workplace Efficiency Issues:

- Support and industrial use spaces have been converted to office use resulting in an elimination of required field staff training facilities, and compromises in change rooms and industrial hygiene areas; and

- An internal review of departmental interdependencies revealed that the locations of frequently collaborating business units are placed far apart, decreasing efficiency and productivity.

Due to the issues outlined, it was concluded that the existing facility was utilized beyond its capacity and therefore unacceptable to continue operating as the status quo. The decision was made to find alternative options for Enersource's building facility needs.

Facilities Redevelopment for Increased Capacity

Commencing in the spring of 2009, Enersource undertook a review of opportunities for expansion of office space on the existing site. Options for demolition or extensive renovation of the existing office components and/or redevelopment of the site with an office section of greater capacity were considered. Options for expansion of the current site by the acquisition of adjacent industrial land were also reviewed. Eight scenarios as drafted by an architect were considered and were then vetted by industry experts in the field of building construction and property management. Since Enersource is not an expert in the field of building renovations or building design, the expert assessments were valuable, and revealed that expanding the existing Mavis Road facility was not optimal. Costs were expected to be double that of building a new facility on a green-field site.

As well, each option proposed an element of increased capacity but did not address the basic congestion issues of the site.

Site traffic and parking issues would be amplified under all of the Mavis Road redevelopment scenarios. Interim removal of staff and public functions from the site for a period of approximately two years to allow for the demolition of the

existing building and the construction of a new building would be a significant cost burden and provide unacceptable customer service levels. Security would also be an issue as isolation of work areas from public access might not be possible.

In summary, the costs of redeveloping Mavis Road were found to exceed other alternatives to meet the administrative office needs of Enersource. Further, the market value of the renovated facility would not reflect the costs of the renovation due to the customized nature of the building and its zoning. This is discussed further in the next paragraph. Therefore Enersource decided it was not reasonably feasible to redevelop 3240 Mavis Road. It was decided that further expertise was needed.

Building Valuation

Enersource retained an independent accredited company, CB Richard Ellis Limited ("CBRE"), to provide an appraisal of the existing Mavis Road facility in November, 2010. The cover letter of the valuation report is found at Exhibit 2 Tab 2 Schedule 5 Appendix 2. The report indicates a value of $6,875 for the facility at 3240 Mavis Road.

The appraiser concluded that the industrial nature of the property, with its close proximity to the rail line and other heavy industrial uses was unlikely to change in the future. Additional development on the land would not add to the overall value of the property for other potential users, should an exit from the site be required.

As also noted in the prior section, Enersource was advised that adding further capacity to 3240 Mavis Road was not recommended. Costs of further increasing the density on the existing site would not increase the value of the property due

to its zoning, location, and due to the unique nature of Enersource's facility requirements.

Organizational Considerations

In early 2011, Enersource developed an affinities matrix. This is a process of documenting and evaluating the requirement for, and frequency of, interaction between business units. This was developed through consultation with departmental managers. The affinities matrix illustrated that many administrative groups required minimal contact with much of the operations group. Email and scheduled meetings are sufficient for the majority of these relationships. The affinities matrix identified those business units that could be located separately from an operational centre without effect to the business performance. The data from the affinities matrix demonstrated that operational groups could remain at the existing facility with administrative functions able to move to a separate newly established location.

The affinities matrix is provided as Exhibit 2 Tab 2 Schedule 5 Appendix 3.

Strategic Facility Plan Development

Through Enersource's standard Request for Proposals ("RFP") process, it retained further expertise from Avison Young Commercial Real Estate (Ontario) Inc. ("Avison Young"). Avison Young undertook an extensive review of function, forecast, and anticipated business activities. The review included a needs analysis and a review of the business structure. Avison Young's study analyzed the options for a new administration building which would allow for a reversal of industrial facilities at Mavis Road back to their intended operational use.

The relocation of the administrative groups would include the customer payments centre, executive, board meeting facilities, training facilities and financial

management filings and records. It was expected that 150 current administrative staff and their related support facilities would be relocated from 3240 Mavis Road.

The new facility would allow for the creation of facilities dedicated to customer education and outreach that form part of the Enersource strategic plan, which were not possible in the Mavis Road configuration.

The spatial forecast of the new administration facility included future project capacity and fifteen years of forecast business activity growth. This is described more fully below.

Spatial Requirements

A full spatial requirement profile of a new office ("Administration Office") was created during June and July, 2011. The spatial profile quantified current and future staffing requirements, facility support areas, filing, office services and storage needs, as well as ancillary and public facility requirements.

The spatial database documented individual employee positions in each group and work area. The result was a working document that will be updated over time and will provide a key tool for planning purposes.

The results of the database development showed the requirement for 82,700 square feet to accommodate the staffing level at the Administration Office within five years of the move-in date. Recent employee growth trends were used to assess the spatial requirements for an additional five years, until 2021.

The Space Forecast Modeling Summary is provided at Exhibit 2 Tab 2 Schedule 5 Appendix 4.

Conclusion of the Strategic Facility Plan Development

Enersource concluded that to maximize customer value, and to meet the needs of employees and other stakeholders, it should pursue the acquisition of a standard office building for an administration office and to return the 3240 Mavis Road property to an operational configuration in keeping with its capabilities and original design intent.

Undertaking the facility plan development defined Enersource's facilities requirements, and led to further review of the market alternatives. This process will now be described in more detail in the following sections. This process ultimately led to the purchase of an existing office building at 2185 Derry Road.

Analysis of Available Sites and New Building Alternatives

Various options for the new Administration Office were considered. The assistance of the external consultant, Avison Young, continued to provide considerable guidance throughout this process.

The initial acquisition approach focused on undeveloped commercial land, zoned appropriately for a new office building construction. Vacant land in the target area independently available for sale is limited. A majority of land is held by institutional and pension fund holdings, typically in large parcels. Over thirteen opportunities were visited, analyzed, and ranked. The top four sites proceeded to the offer of purchase and sale stage. In each case, factors of lot over-sizing, other bidders in the marketplace, or the nature of the encumbrances of the property prevented the acquisitions from being completed. It was concluded that no land acquisition was possible with the locational, economic, and timing parameters required by Enersource.

In conjunction with the analysis of property acquisition, an RFP process was undertaken for design/build constructors for the Administration Office. The RFP result provided a defined cost of constructing a building on the anticipated vacant land. The RFP was sent to five reputable design/build constructors. Enersource met with the five companies to review their proposals. Three of the five proposals met Enersource's design specifications. The building project cost evaluations ranged from $11,600 to $13,600, not including land.

Coincident with the search for land and design/build constructors, Avison Young performed a comprehensive search of existing facilities in the marketplace that met Enersource's requirements. One facility, 2185 Derry Road, was identified that met all of the requirements in the targeted geographic area. Derry Road was originally constructed as, and owned by, a corporate head office. However, this location was only offered on a lease. Enersource agents approached the owners of Derry Road and undertook a negotiation for a purchase.

Table1 below provides a summary of the estimated capital costs and annual rate impacts of the various opportunities that were available for the new Administration Office: procuring land/constructing a new building; purchasing an existing building; and leasing office space.

Table 1 identifies that purchasing an existing building had the lowest annual rate impact, at $3,052. Enersource is very concerned with minimizing the rate impacts on its customers. The Derry Road purchase was a necessary initiative that met all of Enersource's criteria, at the lowest annual rate impact to customers.

Table 1: Summary of Proposed Alternatives for the Enersource Administration Office Accommodation Strategy ($000s)

Alternatives	Initial Capital Investment	2013-2017 Outflows	2013-2017 Inflows Rate Impact	Annual Revenue Requirement Impact
Option 1. Construct New Building	(22,473)	(8,271)	16,688	3,338
Option 2. Purchase 2185 Derry Rd	(20,069)	(7,653)	15,260	3,052
Option 3. Lease Office Space	(1,310)	(16,587)	17,071	3,414

Decision and Current Status

Market conditions precluded the purchase of land and the independent construction of a new building within the target area.

Negotiations for the purchase of Derry Road resulted in an opportunity to develop significant value via the acquisition, and to address, in a very timely fashion, the staff over-crowding and other congestion and environmental issues of the current facilities.

The building condition report for Derry Road, undertaken by an independent consultant, identified the investment required to offset some aging and deferred maintenance in the building, and the investment required to ready the facility for Enersource`s utilization. The costs associated with this remedial work have been included in the capital costs provided below in Table 2 for the acquisition.

The process of due diligence and documentation for sale concluded in April, 2012.

Building condition upgrades as identified in the building condition report and other low impact interior modifications are to be undertaken in the summer of 2012.

The move into the new building is scheduled for September, 2012.

Capital Cost Summary of Administration Office and Operations Centre

The capital costs of the purchase of the Derry Road facility and reconfiguration of the Mavis Road facility to the Operations Centre are shown in Table 2 below.

The reconfiguration of the Mavis Road facility to the Operations Centre is expected to cost approximately $4,000 in 2013 and $1,000 in 2014. The move of administrative staff to the new Administration Office in 2012 will allow Enersource to reconfigure and do some long-needed work at the Operations Centre. This work includes replacing windows to enhance the energy efficiency and address environmental issues in the building, and replacing aged workstations, carpet, and lighting. Much of the HVAC that has reached the end of its useful life will also be replaced. Training areas for the outside staff for “in-class” and “hands-on” trades training will be created, and washroom facilities for outside staff will be renewed. Asphalt paving of the entire yard will also be completed.

Table 2: Building Investments, 2012 to 2014 ($000s)

Total Budget CGAAP

Location	2012	2013	2014	Total
Derry	$20,000			$20,000
Mavis		4,000	1,000	5,000
Total	**$20,000**	**$4,000**	**$1,000**	**$25,000**

Total Budget IFRS

Derry	$19,952			$19,952
Mavis		$3,962	$990	$4,952
Total	**$19,952**	**$3,962**	**$990**	**$24,904**

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INDOOR AIR QUALITY ASSESSMENT

ENERSOURCE HYDRO MISSISSAUGA
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FINAL REPORT

Assessment performed: August 11, 2010
Final Report issued: September 8, 2010
THEM Project #: 13923

Prepared by:

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EXECUTIVE SUMMARY

Personnel from T. Harris Environmental Management Inc. (THEM) conducted an indoor air quality (IAQ) assessment in selected areas of Enersource Hydro Mississauga building located at 3240 Mavis Road, Mississauga, Ontario. The assessment was performed on August 11, 2010 between approximately 9:00 AM and 5:00 PM.

This assessment was conducted at the request of Mr. Bernie Haines, Director-Health, Safety & Security of Enersource Hydro Mississauga, in order to evaluate air quality within the selected areas of the building. Mr. Bernie Haines, Director-Health, Safety & Security and Ms. Khorshed Merwan, Labour Co-Chair Joint Health and Safety Committee member of Enersource Hydro Mississauga, provided assistance to THEM personnel during the assessment. The present IAQ assessment is the follow-up to an indoor air quality assessment (IAQ) conducted in December 15 2009. The scope of work for the present assessment is similar to the survey performed on December 15, 2009. IAQ sample locations were selected throughout the building (including basement level) covering the majority of areas normally occupied during working days. Areas assessed during the study included Stores, Garage, Metering Department, South Tower 2nd and 3rd Floor, the Middle Building, Accounting Offices, Finance, Information Technology, North Tower 2nd and 3rd Floor, Health, Safety & Security, Human Resources, and Customer Service. A visual inspection of the air handling units (AHUs) was also conducted as a part of the present assessment.

Based on the air sampling results and observations made on the survey date, the following conclusions and recommendations can be made:

Visual Inspection of Office Spaces and AHUs

- Sporadic black streaks or smudges were noted near air supply for the Mechanic Office and Trades Training Area (Appendix I, Photograph 2). The presence of black streaks on air supply diffusers indicate an event characterized by the supply of insufficiently filtered air.
    - Supply air diffusers, return grills and ceiling tiles identified to have particulate accumulation should be cleaned. In the event that the problem persists within an area, the source of particulate accumulating on these surfaces should be identified and rectified. Overall, it is important to replace filters regularly within the HVAC system to optimize performance and reduce dust particulate levels within tenant spaces.
- Minor deficiencies included a couple of damaged ceiling tiles and water stained tiles where observed in Mechanic Office, Mr. Sam Ramtahal office and Mr. J. P's office. It is recommended that damaged and water stain tiles be replaced as part of regular maintenance activities. (Appendix 1, Photograph 1, 3, 4)

- An intact ceiling plenum serves as a path for room air to return to the air handling units. Missing and damaged ceiling tiles may disrupt the flow of return air and reintroduce air in the occupied space without being properly filtered and conditioned. As a part of general maintenance activities, deficiencies noted should be rectified by replacing all deficient ceiling tiles (physically damaged or water-damaged) and adjusting poorly fit ceiling tiles to ensure the efficient operation of the HVAC system as intended.

- Water-damaged ceiling tiles indicate past or present water leakage, an undesirable condition recognized to promotion of mould growth on affected surfaces. The underlying cause of the water infiltration onto the surface of the tiles should be identified and rectified

- It is recommended that cleaning of Roof Top Units (RTUs) should be performed on a regular basis to prevent the accumulation of dust and debris. RTU #1 and RTU# 4 and RTU# 11 panel insulation were deteriorated. The overall condition of filters was low to heavy dust loading (Appendix I, Photograph 5, 6 and 7).

    - Saturated filters could potentially cause undue stress on the air-handling unit by forcing the fan unit to work harder than necessary. Saturated filters could also serve as a breeding ground for bacteria and fungi and a source of microbial volatile organic compounds. Filters should be changed as part of regular maintenance activities in accordance with ASHRAE Standard 62.1-2007

- High occupant density was observed in the Customer Service Department and Purchasing Department.

    - ASHRAE Standard 62.1-2007 provides a guideline level for occupant density in office spaces of 5 individuals per 1,000 square feet and fresh air addition rate of 17 cfm / person established to promote good indoor air quality.

- Improperly maintained air handling units (AHUs) not only affect the energy consumption efficiency of the units, but also adversely affect the indoor air quality (IAQ) of a building. It is recommended that a professionally developed preventative maintenance program be developed, implemented and monitored. Generally, a preventive maintenance program including periodic inspection and cleaning of air handling units is required in order to maintain them in adequate operating condition. The U.S. National Air Duct Cleaners Association (NADCA) *Standard ACR 2005 – Assessment, Cleaning, and Restoration of HVAC Systems* recommends periodic HVAC cleanliness inspection" of air handling units (1 year), supply ductwork (2 years) and return/exhaust ductwork (2 years). In addition,

according to the ASHRAE Standard 62.1-2007, the HVAC system should be operated and maintained at a minimum in accordance with the provisions of this Standard as outlined in Table 8-1 attached in Appendix IV

- The introduction of fresh air to an occupied space allows the dilution of contaminants and odours generated indoors by humans, interior furnishings, office equipment, cleaning agents, live plants, and other indoor sources. It is recommended that Enersource Hydro Mississauga explore options (natural ventilation or mechanical ventilation) to introduce additional fresh air in areas where elevated carbon dioxide (CO_2) and TVOC levels were observed.

Thermal and IAQ Parameters

- Temperature levels ranged between 22.4 and 27.0 ˚C among all locations tested. The majority of the temperature readings were within the ASHRAE guideline range between 22.5 - 26.0 ^{o} C for the summer season and were acceptable. It is recommended that the temperature controls be adjusted such that a temperature reading between 22.5 – 26.0 ^{o} C is maintained in all locations during normal business hours in the summer months. The ASHRAE temperature guidelines are designed to be acceptable for the majority (approximately 80 %) of occupants

- Relative humidity (% RH) levels ranged between 39.3 and 73.2 %. For all office locations tested with an average relative humidity of 50.5 % for the morning measurements and 50.6 % for the afternoon. The majority of the relative humidity measurements were within the ASHRAE guideline for relative humidity of 20% to 60% and acceptable.

  - High humidity levels can result in condensation within the building structure and on interior or exterior surfaces, and subsequent development of fungal growth. In order to prevent development of microbial contamination relative humidity must be maintained below 60%, as recommended by ASHRAE.

- Carbon dioxide (CO_2) levels ranged between 423 and 1678 ppm for all locations tested throughout the sampling period with average concentrations of 886.9 ppm in the morning and 855.4 ppm in the afternoon (Graph 3, Appendix II). The majority of the CO_2 measurements collected in the office environments were well below the ASHRAE guideline CO_2 concentration of 937 ppm (a concentration of 600 ppm above the measured average outside CO_2 concentration of 337 ppm) and acceptable. The CO_2 concentration exceeded the IAQ guideline in the Accounting Office, Finance Department, IT Department and Customer Service Department, suggesting that an inadequate amount of fresh air is being provided to these areas. It is recommended that the amount of fresh air to be increased to reduce the effect of build-up CO_2 levels.

- Carbon monoxide (CO) concentrations ranged from 0 ppm to 1.9 ppm in all sample locations tested, which is well below the ASHRAE guideline maximum CO concentration of 9 ppm.

- Particulate matter (PM_{10}) levels ranged from 4 to 144 µg/m^3 for all locations tested, with an average concentration of 21.4 µg/m^3 in the morning and 19.5 µg/m^3 in the afternoon. Majority of the particulate matter readings remained relatively constant and below the respective WHO recommended 24-hour guideline value of 50 µg/m^3 (Graph 5, Appendix II). However, particulate matter (PM_{10}) levels in the Store Office (99 µg/m^3 (morning)) and Sabrina Scot's Cubicle (114 µg/m^3 (morning)) exceeded WHO IAQ guideline. High levels in Store Office may be due to motor vehicle activities in Warehouse and Garage in the morning.

- TVOC levels ranged between 1 and 440 ppb for all locations tested on the survey date. The majority of the TVOC readings were within the *Comfort Range* (<90 ppb) as established by the Commission of the European Communities and occupants are unlikely to experience discomfort (Graph 6, Appendix II). TVOC levels in some areas within the North Tower 2nd floor, Human Resources, Customer Service and Stores Area during the morning and afternoon sessions (95 – 440 ppb) were at the low end of the *Multifactorial Exposure Range*. Within the *Multifactorial Exposure Range* (90 - 1300 ppb), sensitive or susceptible individuals may experience irritation or discomfort if other IAQ parameters like temperature, relative humidity, or particulate levels are not within their respective recommended ranges. High level of TVOC within the North Tower 2nd floor can be attributed to use of hand sanitizer. Nevertheless, all of the measured TVOC concentrations were within the Health Canada target guideline level of 1,000 µg/m^3 (440 ppb).

    - Open characterization air sampling for VOC is recommended for odour complaints to identify sources.

No detectable amounts of sulphur dioxide, nitrogen oxides, formaldehyde, or ozone were noted at the locations tested. Concentrations of these gases were below the limits of detection for the method of analysis and were considered acceptable for indoor air quality based on their recommended exposure guidelines.

General

- The contents this report should be made available to the Joint Health and Safety Committee or safety representative.

This executive summary is not to be used alone and the report should be reviewed in its entirety.

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Indoor Air Quality Assessment
Enersource Hydro Mississauga **THEM # 13923**
3240 Mavis Rd, Mississauga, ON

September 8, 2010

Enersource Hydro Mississauga
3240 Mavis Road
Mississauga, Ontario
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ATTN: Mr. Mr Bernie Haines, Director-Health, Safety & Security

RE: Indoor Air Quality Assessment (THEM Project #13923)
Enersource Hydro Mississauga
3240 Mavis Road, Mississauga, Ontario
L5C 3K1

1.0 BACKGROUND

Personnel from T. Harris Environmental Management Inc. (THEM) conducted an indoor air quality (IAQ) assessment in selected areas of Enersource Hydro Mississauga building located at 3240 Mavis Road, Mississauga, Ontario. The assessment was performed on August 11, 2010 between approximately 9:00 AM and 5:00 PM.

This assessment was conducted at the request of Mr. Bernie Haines, Director-Health, Safety & Security of Enersource Hydro Mississauga, in order to evaluate air quality within the selected areas of the building. Mr. Bernie Haines, Director-Health, Safety & Security and Ms. Khorshed Merwan, Labour Co-Chair Joint Health and Safety Committee member of Enersource Hydro Mississauga, provided assistance to THEM personnel during the assessment. . The present IAQ assessment is the follow-up to an indoor air quality assessment (IAQ) conducted in December 15 2009. The scope of work for the present assessment is similar to the survey performed on December 15, 2009. IAQ sample locations were selected throughout the building (including basement level) covering the majority of areas normally occupied during working days. Areas assessed during the study included Stores, Garage, Metering Department, South Tower 2nd and 3rd Floor, Accounting Offices, Finance, Information Technology, North Tower 2nd and 3rd Floor, Human Resources, and Customer Service. A visual inspection of the air handling units (AHUs) was also conducted as a part of the present assessment.

To evaluate the air quality within the investigated areas, spot monitoring for a number of IAQ parameters was conducted. These parameters included thermal comfort parameters: temperature and relative humidity, as well as general air quality parameters: carbon dioxide (CO_2), carbon monoxide (CO), total volatile organic compounds (TVOC), and particulate matter (PM_{10}). Furthermore, grab sampling for common indoor air pollutants such as sulphur dioxide (SO_2) nitrogen oxides (as NO_2), ozone (O_3), and formaldehyde (CH_2O) was performed. A visual

inspection of the air handling units (AHUs) was also performed as a component of the present assessment.

2.0 INTRODUCTION

More than one third of energy consumed in North America is used in buildings for heating, cooling, lighting and ventilation. The conditioning and transportation of ventilation air accounts for 50 – 60 % of total building energy requirements. In spite of this, a recent survey has shown that 65 % of all office buildings operate under sick building syndrome (SBS) conditions, resulting in an estimated loss of annual productivity equivalent to several billion dollars. Office air contaminants are ubiquitous. They might include malodorous gases and vapours, allergens, irritants such as formaldehyde and acutely toxic agents such as carbon monoxide. Asbestos and radon could also be present, but these are unlikely causes of complaints of acute health effects. Problems associated with these indoor air contaminants occur when concentrations are elevated, often because of heating, ventilating and air conditioning (HVAC) system problems. In an IAQ investigation, basic deficiencies in HVAC system design and operation are considered, such as inadequate supply of outdoor air, improperly positioned fresh air intakes, improper control system strategy, ineffective air distribution and inadequate air filtration, humidity control or maintenance.

2.1 Standards and Guidelines

Indoor Air Quality

Presently, there are no legally enforceable standards for indoor air pollutants in residential and institutional buildings, and non-industrial workplaces in Canada. However, various organizations have published guidelines for evaluating indoor air quality. These air quality guidelines specify maximum concentrations and exposure times for specific contaminants in indoor and outdoor environments.

The Federal-Provincial Advisory Committee on Environment and Occupational Health, under the auspices of Health Canada, established "acceptable" IAQ guidelines for known indoor air contaminants in two guidelines titled *Exposure Guidelines for Residential Indoor Air Quality (1989)* and *Indoor Air Quality in Office Buildings: A Technical Guide (1995)*, setting out permissible ranges of airborne concentrations for selected substances. The *Exposure Guidelines for Residential Indoor Air Quality* includes an acceptable long-term exposure range (ALTER) that specifies the concentration of a given substance individuals may be exposed to throughout a lifetime without affecting their health. Similarly, an acceptable short-term exposure range (ASTER) defines the concentration of a substance to which people can be safely exposed to within a specified time.

The *Indoor Air Quality in Office Buildings: a Technical Guide* stipulates that the generally accepted guidelines for ventilation and indoor air quality are the American Society of Heating, Refrigerating, and Air Conditioning Engineers *(ASHRAE), Standard 55-2004, Thermal Environmental Conditions for Human Occupancy*, and *ASHRAE Standard 62.1-2007, Ventilation for Acceptable Indoor Air Quality*. These standards give recommended guidelines for thermal comfort parameters and specific chemical contaminants in mechanically ventilated buildings.

ASHRAE Standard 62.1-2007 also recommends outdoor air mechanical ventilation rates for office spaces, schools, and other institutions. Under this standard, the recommended outdoor air ventilation rate is 17 cfm (cubic feet per minute) per person for a typical office, based on an estimated maximum occupancy of five (5) people per 1,000 ft^2. At this ventilation rate, a steady-state CO_2 concentration of no greater than about 600 ppm above outdoor levels develops in an occupied space with the assumption that make-up air is of satisfactory quality, and outside CO_2 concentrations are in the 300 to 500 ppm range.

On the day of our IAQ assessment (August 11, 2010), a guideline CO_2 concentration of 1154 ppm (a concentration of 600 ppm above the measured average outside CO_2 concentration of 554 ppm) would indicate an adequate supply of fresh outside air at a ventilation rate of 17 cfm per person occupying an office area. Even though this ventilation rate can be considered acceptable for a typical office environment, certain airborne contaminants may be relatively higher depending on their content in the fresh outdoor air introduced. Therefore, in some buildings, indoor air quality may not meet all the requirements of the ASHRAE standards.

Ontario Regulation 833 (R.R.O. 1990, Reg. 833 as amended to O. Reg. 83/07) *Control of Exposure to Biological or Chemical Agents – made under the Occupational Health and Safety Act*, establishes occupational exposure limits for a number of chemical contaminants in Ontario workplaces. These occupational exposure limits were originally developed for the protection of workers in manufacturing environments, and therefore are not appropriate for use in assessing indoor air quality in occupied office areas. However, these are legally enforceable limits in Ontario.

Indoor air quality guidelines are given above in Table I.

TABLE I
Indoor Air Quality Guidelines

Parameter	Units	ASHRAE	Health Canada		WHO	Ontario Regulation
			ASTER	ALTER		TWAEV
Thermal Comfort:						
Temperature	°C	20 – 23.5 (Winter) 22.5 - 26 (Summer)	-	-	-	-
Relative Humidity	%	20 – 60 [1]	50 (Summer) 35 (Winter)[2]	-	-	-
General IAQ:						
Carbon Dioxide	ppm	600 above exterior CO_2 concentration (17 cfm/person)	-	≤ 3,500	-	5,000
Carbon Monoxide	ppm	9 (8 hr.) 35 (1 hr.)	≤ 11 (8 hr.) ≤ 25 (1 hr.)	-	10 (8 hr.) 25 (1 hr.) 50 (30 min.) 90 (15 min.)	25
Particulate Matter PM_{10} [3]	µg/m^3	150 (24 hour)	-	-	20 (1 year) 50 (24-hr.)	3,000 (as respirable particulate)
Particulate Matter $PM_{2.5}$ [4]	µg/m^3	15 (annual) 35 (24-hour)	≤ 100 (1 hr.)	≤ 40	10 (1 year) 25 (24-hr)	3,000 (as respirable particulate)
Common Indoor Air Pollutants						
Formaldehyde	ppm	0.4[5]	0.10[6] (1 hr) 0.040[6] (8 hr)		0.081 (30 min.)	1.0[7] 1.5[8]
Nitrogen Dioxide	ppm	0.05 (1 year)	≤ 0.25 (1hr.)	≤ 0.05	0.1 (1 hr.) 0.02 (1 year)	3
Ozone	ppm	0.08 (8 hr)	≤ 0.12 (1 hr.)	-	0.051 (8 hr.)	0.1 0.3[7]
Sulphur Dioxide	ppm	0.14 (24 hr.) 0.03 (annual)	≤ 0.38 (5 min.)	≤ 0.019	0.008 (24 hr.) 0.19 (10 min.)	2 5[7]

[1] 2007 ASHRAE Handbook – HVAC Applications; Range given is for office buildings
[2] Ideal indoor relative humidity levels in most Canadian cities
[3] for particles 10 µm or smaller in mass median aerodynamic diameter
[4] for particles 2.5 µm or smaller in mass median aerodynamic diameter
[5] ASHRAE refers to the formaldehyde concentration of 400 ppb (500 µg/m^3) recommended by US Department of Housing and Urban Development.
[6] Health Canada "Residential Indoor Air Quality Guideline"
[7] Short Term Exposure Value (STEV)
[8] Ceiling Exposure Value (CEV)

The World Health Organization (WHO) document *Guidelines for Air Quality* (2000) publishes levels for a variety of air pollutants. The WHO guidelines do not differentiate between outdoor and indoor air quality, and are aimed at protecting the health of the general population including sensitive population subgroups such as the elderly and asthmatics. The WHO expresses its guidelines as a Guideline Value (GV) or Tolerable Concentration (TC) for those pollutants with non-carcinogenic health endpoints. For pollutants having carcinogenic health endpoints, the WHO publishes unit risks instead of GVs or TCs, based on an average ambient air concentration.

An averaging time for each value is also specified depending on the type of effects that are caused by exposure to the pollutant. In addition, the WHO document *Air Quality Guidelines – Global Update* (*2005*) published levels for particulate matter, ozone, nitrogen dioxide, sulphur dioxide and updated air quality guidelines for these contaminants.

The elimination of all effects, such as unpleasant smell or mild irritation, is not attempted and therefore TWAEVs may not be appropriate for use in assessing IAQ in office and institutional workplaces. For contaminants where IAQ standards or guidelines have not been established, it has been customary to assume as a first guide that a concentration of 1/10th the TWAEV would not produce complaints in a non-industrial population in residential, office, school or other similar environments. However, this general guideline may not provide an environment satisfactory to individuals who are sensitive to a particular contaminant.

2.2 Total Volatile Organic Compounds (TVOC)

Volatile organic compounds (VOCs) refer to a variety of airborne contaminants that are commonly found inside buildings at detectable concentrations. They are carbon-based air contaminants that possess sufficient vapour pressure so that they may exist as vapours at typical indoor temperatures. VOCs include several chemical classes such as alkanes, aromatic hydrocarbons, terpenes, halocarbons, esters, aldehydes and ketones. They are commonly found to off-gas from a variety of building materials and products such as carpets, furnishings, pesticides, photocopiers, printers, adhesives, paints and coatings, cleaning compounds, synthetic textiles, waxes, and tobacco smoke.

Airborne VOC concentrations may be elevated because of “off-gassing” of VOCs, which are constituents of building materials such as carpets or infiltration of contaminants from outdoor air. If there is inadequate ventilation for the concentration of VOCs off gassing within the space, these chemicals can build up to concentrations, which may cause health effects. Typical health effects from exposure to VOCs include discomfort and irritation to the eyes and mucous membranes. Higher concentrations may result in the onset of headaches and additional neurotoxic effects.

VOCs are present as a mixture of potentially several hundred or thousands of components and there are no specific exposure regulations or standards available for total VOCs (TVOC). Several groups have focused on the health effects of individuals exposed to multiple VOCs and

have helped to develop exposure guidelines. Although there are presently no Canadian or U.S. standards for TVOC, target and action values of 1,000 and 5,000 µg/m^3, respectively are being discussed by Health Canada.

TVOC concentrations below 200 µg/m^3 are considered in the *Comfort Range* according to Lars Mølhave[9]. At a TVOC exposure range of 200 µg/m^3 to 3,000 µg /m^3, odours, irritation and discomfort may result in response to the presence of TVOC together with thermal comfort factors and other stressors. This range is known as the *Multifactorial Exposure Range*. Above 3,000 µg/m^{3,} one may expect complaints.

TVOC guidelines suggested by the Commission of the European Communities[10], based on the work of Lars Mølhave and guidelines from Health Canada are summarized below in Table II.

TABLE II
Summary of TVOC Exposure Guidelines

Organization	TVOC Concentration [11]	Exposure Range	Health Effects
Commission of the European Communities	< 200 µg/m^3 (90 ppb)	Comfort Range	No irritation or discomfort.
	200 - 3,000 µg/m^3 (90 - 1300 ppb)	Multifactorial Exposure Range	Irritation or discomfort possible if other exposures interact.
	3,000 - 25,000 µg/m^3 (1300 -10,900 ppb)	Discomfort Range	Exposure effects and probable headache if other exposures interact.
	>25,000 µg/m^3 (10,900 ppb)	Toxic Range	Additional neurotoxic effects other than headache may occur.
Health Canada	1,000 µg/m^3 (440 ppb)	Target Level	-
	5,000 µg/m^3 (2,200 ppb)	Action Level	-

[9] Mølhave L: Volatile Organic Compounds, Indoor Air Quality and Health" *Indoor Air*, 4, 357 – 376 (1991)
[10] The European Collaborative Action Report No. 19: "Total Volatile Organic Compounds (TVOC) in Indoor Air Quality Investigations" (EUR17675 EN, 1997)
[11] µg/m^3 expressed as toluene equivalents and ppb as isobutylene equivalents

3.0 METHODOLOGY

3.1 Visual Inspection of Air Handling Units (AHUs)

The investigated areas included a combination of open-concept and individual offices within all building towers. A visual inspection of the building's air handling units (AHU) located on rooftop was performed. The AHU components such as air intake, filtration unit, heating and cooling coils units, supply and return fans were visually inspected. The extent of contamination and/or deterioration of the system's components were examined where applicable. Cleanliness of the overall ventilation system components and chambers was also inspected and noted. Photographs are provided in Appendix I.

3.2 Spot Monitoring for Thermal Comfort and IAQ Parameters

Spot measurements of temperature, relative humidity, carbon dioxide (CO_2) and carbon monoxide (CO) were taken using a *TSI Q-Trak IAQ Monitor* (Model 8551). This instrument has four separate sensors (one for each parameter) that are described below.

Temperature was measured with a thermistor sensor that has an operating range of 0 to 51 °C (32 to 122 °F) and an accuracy of ± 0.6 °C (1 °F). Humidity was determined using a thin-film capacitive sensor, which has an operating range of 5 to 95 % RH and an accuracy of ± 3 % RH. Concentrations of carbon dioxide (CO_2) were determined by a non-dispersive infrared (NDIR) sensor that has an operating range of 0 to 5,000 ppm and an accuracy of ± 50 ppm. Carbon monoxide (CO) concentrations were determined using an electro-chemical sensor that has an operating range of 0 to 500 ppm and an accuracy of ± 3 % or ± 3 ppm, whichever is greater. The instrument is calibrated for carbon monoxide and carbon dioxide monthly and calibrated by the manufacturer for all parameters yearly.

Airborne particulate matter (PM_{10}) spot measurements were taken using a *TSI Dust-Trak Aerosol Monitor* (Model 8520). This device instantaneously measures average, minimum and maximum particle concentrations for particles between 0.1 and 10 µm in diameter, with a measuring range of 1 $\mu g/m^3$ to 100 mg/m^3. On-site instrument zero calibration and flow rate check was conducted for the *Dust-Trak Aerosol Monitor* prior to the beginning of the sampling period.

3.3 Total Volatile Organic Compounds (TVOC)

Spot measurements for TVOC were taken using a *ppbRAE Plus VOC Monitor* (Model PGM - 7240) at the same locations where air quality parameters were measured. This device measures instantaneous, average, short-term exposure level (STEL) TVOC exposure levels and peak

values in parts per billion (ppb). The instrument has a 10.6 eV photo ionization detector (PID) that has an operating range of 0 to 2,000 ppb with an accuracy of ± 20 ppb. The device has an internal integrated flow rate of 400 cubic centimetres per minute. The PID was calibrated on-site on the survey date with isobutylene gas of known concentration that was used as a reference standard gas. On-site zero calibration was also performed prior to the beginning of the survey period. Spot measurements using the *ppbRAE Plus VOC Monitor* do not distinguish individual VOC constituents but provides a total VOC (TVOC) concentration as isobutylene equivalents.

3.4 Common Indoor Air Pollutants

Screening for common indoor air pollutants was conducted using grab-sampling techniques. Ambient air samples were collected using *Gastec Analyzer Tubes* for sulphur dioxide (SO_2), ozone (O_3), nitrogen oxides (NO_x) and formaldehyde (CH_2O). These tubes are direct-reading colourimetric detector tubes and provide rapid, quantitative analysis of the concentrations of chemicals in air with a minimum accuracy of ± 25 %, utilizing the *Gastec Multi-Stroke Gas Pump* (Model GV-100). Sampling for the above indoor air pollutants was performed on selected floors of the building.

Grab sampling techniques, as used for the determination of toxic gases during this study, are not suitable for accurate determination of low-level exposure due to their limits of detection. However, they are acceptable methods for the identification of these gases in IAQ investigations.

4.0 RESULTS

4.1 Visual Inspection of Office Spaces and AHUs

The Enersource Hydro Mississauga building is comprised of a basement level and the main, second and third floors. The scope of work was limited to locations in the building specified by Mr. Haines. These areas included Stores, Garage, Trouble Department, Metering Department, South Tower 2nd and 3rd Floor, Accounting Offices, Finance, Information Technology, North Tower 2nd and 3rd Floor, Human Resources, and Customer Service. Typical basic building components within these areas consist of suspended ceiling tiles, carpeted, vinyl, and/or tile flooring, and inoperable windows. In addition, the office areas are generally furnished with low and high height partitioned workstations and fluorescent lighting.

Levels of occupancy varied on different floors. For example, the *Accounting Department* (Basement floor) was densely occupied, which explains observed high CO_2 levels. According to Mr. Bernie Haines there is a consistent odour in Mr Ron Jones office (Appendix II, Table A).

THEM personnel noted water damage on some ceiling on different floors. THEM personnel also noted dirty air diffusers in Trades Training Area. and Mechanic Office areas. This deficiency can

negatively affect indoor air quality. A photograph of the observed deficiency is documented and is presented in Photographs 1 to 12, Appendix I

The office space inspected was generally well kept with no significant contaminant or odour sources observed throughout the occupied areas.

The condition of AHUs serving the building is summarized below in Table III. Photographs showing some of our visual observations are included in Appendix I.

TABLE III
Summary of AHU Inspections
Enersource Hydro Mississauga
3240 Mavis Rd, Mississauga, ON

AHU #	General Conditions	Dampers	Filters	Heating/ Cooling Coils	Air Supply Fan
RTU #1	Deteriorated fibre insulation on panels	Unobstructed	Pleated filters; low dust loading	Clean, dry, and in good condition	Appeared to be in good condition
RTU #2	Clean and dry	Unobstructed	Pleated filters; heavy dust loading	Clean, dry, and in good condition	Appeared to be in good condition
RTU #3	Clean and dry	Unobstructed	Pleated filters; heavy dust loading	Clean, dry, and in good condition	Appeared to be in good condition
RTU #4	Deteriorated fibre insulation on panels	Unobstructed	Pleated filters; medium dust loading	Clean, dry, and in good condition	Dusty fan unit; loose fan insulation
RTU #5	Clean and dry	Unobstructed	Pleated filters; low dust loading	Clean, dry, and in good condition	Appeared to be in good condition
RTU #6	Clean and dry	Unobstructed	Pleated filters; low dust loading	Clean, dry, and in good condition	Appeared to be in good condition

AHU #	General Conditions	Dampers	Filters	Heating/ Cooling Coils	Air Supply Fan
RTU #7	Clean and dry	Unobstructed	Pleated filters; low dust loading	Clean and dry; slight coil damage	Appeared to be in good condition
RTU #8	Deteriorated fibre insulation on panels	Unobstructed	Pleated filters; low dust loading	Clean, dry, and in good condition	Appeared to be in good condition
RTU #9	Clean and dry	Unobstructed	Pleated filters; low dust loading	Clean and dry; slight coil damage	Appeared to be in good condition
RTU #10	Clean and dry	Unobstructed	Medium dust loading in polyester filters.	Clean, dry, and in good condition	Loose insulation in fan unit and dusty
RTU #11	Deteriorated fibre insulation on panels	Unobstructed	low dust loading in polyester filters	Clean, dry, and in good condition	Loose insulation in fan unit and dusty
MAU #1	Clean and dry	Unobstructed	Low dust loading in polyester pre-filters; medium dust loading in pleated filters	Clean, dry, and in good condition	Appeared to be in good condition
MAU #2	Clean and dry	Unobstructed	Heavy dust loading in polyester pre-filters; medium dust loading in pleated filters	Clean, dry, and in good condition	Appeared to be in good condition
MAU #3	Clean and dry	Unobstructed	Pleated filters; heavy dust loading	Clean, dry, and in good condition	Appeared to be in good condition

As shown above in Table III, the air handling unit systems and components inspected, where accessible, appeared to be properly maintained. A few minor deficiencies were noted as follows:

- The pre-filters in RTU # 2, 3 and MAU 2, 3 were observed to be heavily loaded with dust. These filters are reportedly changed quarterly (Appendix 1, photograph 1, 2).
    - Saturated filters could potentially cause undue stress on the air-handling unit by forcing the fan unit to work harder than necessary. Saturated filters could also potentially serve as a breeding ground for bacteria and fungi and a source of volatile organic compounds. Filters should be changed as part of regular maintenance activities in accordance with ASHRAE Standard 62.1-2007
- Insulation material found on panels of HVAC (RTU # 1, 4, 8 and 11) was found to be deteriorating.
    - Deteriorated fibreglass lining within an HVAC system can be a source of airborne particulate and entrained in the supply air into the occupied areas of the building.
- Generally, a preventive maintenance program including periodic inspection and cleaning of main and compartmental air handling units is required in order to maintain them in adequate operating condition. The U.S. National Air Duct Cleaners Association (NADCA) *Standard ACR 2005 – Assessment, Cleaning, and Restoration of HVAC Systems* recommends periodic HVAC cleanliness inspection" of air handling units (1 year), supply ductwork (2 years) and return/exhaust ductwork (2 years). In addition, according to the ASHRAE Standard 62.1-2007, the HVAC system should be operated and maintained at a minimum in accordance with the provisions of this Standard as outlined in Table 8-1 attached in Appendix IV.

4.2 Spot Monitoring of IAQ Parameters

Results of IAQ spot testing performed in selected areas are summarized below in Table IV. Graphs and tables showing detailed sampling locations of the spot measurements are given in Appendix II.

TABLE IV
Summary of Thermal Comfort and Air Quality Parameters
Enersource Hydro Mississauga
3240 Mavis Rd, Mississauga, ON

Parameters	**Temp. (°C)**		**Relative Humidity (%)**		**CO_2 (ppm)**		**CO (ppm)**		**PM_{10} ($\mu g/m^3$)**		**TVOC (ppb)**	
IAQ Guideline Level	**22.5 to 26**		**20 to 60**		***1155**		**9.0**		**50**		**90**	
Sampling Round	**R1**	**R2**	**R1**	**R2**	**R1**	**R2**	**R1**	**R2**	**R1**	**R2**	**R1**	**R2**
Mean (Average)	24.0	24.1	50.5	50.6	886.9	855.4	0.4	0.4	21.4	19.5	**68.9**	37.6
Standard Deviation	0.8	1.2	7.6	7.8	266.2	275.4	0.6	0.6	20.3	8.8	**83.6**	36.6
Minimum	22.6	**22.4**	39.3	41.2	445	423	0	0	4	5	0	0
Maximum	**26.3**	**27**	**71.7**	**73.2**	**1678**	**1347**	1.8	1.9	**114**	**43**	**440**	**142**
Range	3.7	4.6	32	32	1233	924	1.8	1.9	110	38	440	142

Bolded values exceed IAQ guidelines, *Values based on 600 ppm above outdoor reading of 554 ppm

Measurements of the above parameters of thermal comfort and indoor air quality were taken twice (morning and afternoon) at each of the sample locations on August 11, 2010 between approximately 9:30 am and 3:30 pm. In addition, outdoor measurements were made in front of the rear entrance of Garage. In summarizing the above spot measurement results for the sampling date, the following trends were noted:

- Temperature levels ranged between 22.4 and 27.0 ˚C among all locations tested with an average temperature of 24.0˚C for the morning and 24.1˚C afternoon measurements. The majority of the temperature readings (84/88) were within the ASHRAE guideline range between 22.5 and 26.0 ^{o} C for the summer season and were acceptable (Graph 1, Appendix II).

    - The IAQ guidelines stipulated by ASHRAE are designed to be acceptable for the majority (approximately 80 %) of occupants. Thermal comfort is a condition of mind, which expresses satisfaction with the thermal environment, and it is assessed by subjective evaluation. Therefore, occupants in the areas noted to be below recommended guidelines may find the temperatures acceptable

- Relative humidity (% RH) levels ranged between 39.3 and 73.2 %. For all office locations tested with an average relative humidity of 50.5 % for the morning measurements and 50.6 % for the afternoon. The majority of the relative humidity measurements were within the

ASHRAE guideline for relative humidity of 20% to 60% and acceptable (Graph 2, Appendix II).

- High humidity levels can result in condensation within the building structure and on interior or exterior surfaces, and subsequent development of fungal growth. In order to prevent development of microbial contamination relative humidity should be maintained below 60%, as recommended by ASHRAE.

Carbon dioxide (CO_2) levels ranged between 423 and 1678 ppm for all locations tested throughout the sampling period with average concentrations of 886.9 ppm in the morning and 855.4 ppm in the afternoon (Graph 3, Appendix II). The majority of the CO_2 measurements collected in the office environments were well below the ASHRAE guideline CO_2 concentration of 937 ppm (a concentration of 600 ppm above the measured average outside CO_2 concentration of 337 ppm) and acceptable. The CO_2 concentration exceeded the IAQ guideline in the Accounting Office, Finance Department, IT Department and Customer Service Department, North Tower 2nd floor suggesting that an inadequate amount of fresh air is being provided to these areas.

- Air quality in these spaces may be perceived as stuffy. Carbon dioxide levels are related to occupant density and activities as well as combustion sources, relative to the outdoor air ventilation rate. ASHRAE recommends a minimum ventilation rate of 10L/s or 17 cfm per person to ensure good IAQ for office spaces, and for occupant density not to exceed 5 individuals per 1,000 square feet.

- Carbon monoxide (CO) concentrations ranged from less than detection limit to 1.9 ppm in all sample locations tested, which is well below the ASHRAE guideline maximum CO concentration of 9 ppm (Graph 4, Appendix II).

- Particulate matter (PM_{10}) levels ranged from 4 to 144 $\mu g/m^3$ for all locations tested, with an average concentration of 21.4 $\mu g/m^3$ in the morning and 19.5 $\mu g/m^3$ in the afternoon. Majority of the particulate matter readings remained relatively constant and below the respective WHO recommended 24-hour guideline value of 50 $\mu g/m^3$ (Graph 5, Appendix II). However, particulate matter (PM_{10}) levels in the Store Office (99 $\mu g/m^3$ (morning)) and Sabrina Scot cubicle (114 $\mu g/m^3$(morning)) exceeded WHO IAQ guideline. High levels in Store Office may be due to motor vehicle activities in Warehouse and Garage during the morning.

  - Excessive levels of particulates can cause allergic reactions, such as dry eyes, contact lens problems, nose, throat, and skin irritation, coughing, sneezing, and respiratory difficulties. The elevated particulate levels are attributed to poor housekeeping / large amount of paper storage and shredding activities / insufficient air filtrations / damage of insulation within the ducts/AHU.

- TVOC levels ranged between 1 and 440 ppb for all locations tested on the survey date. The majority of the TVOC readings were within the *Comfort Range* (<90 ppb) as established by the Commission of the European Communities and occupants are unlikely to experience discomfort (Graph 6, Appendix II). TVOC levels in some areas within the North Tower 2nd floor, Human Resources, Customer Service and Stores Area during the morning and afternoon sessions (95 – 440 ppb) were at the low end of the *Multifactorial Exposure Range*. Within the *Multifactorial Exposure Range* (90 - 1300 ppb), sensitive or susceptible individuals may experience irritation or discomfort if other IAQ parameters like temperature, relative humidity, or particulate levels are not within their respective recommended ranges. High level of TVOC within the North Tower 2nd floor may be attributed to use of hand sanitizer. Nevertheless, all of the measured TVOC concentrations were within the Health Canada target guideline level of 1,000 $\mu g/m^3$ (440 ppb).

  - Customer Service area has both elevated TVOC and elevated carbon dioxide levels which are both indicators of insufficient fresh addition to the space.

  - It is recommended that further investigation is conducted, focusing on identification of potential VOC sources within the assessed area, including open characterization sampling, allowing for identification of most commonly encountered VOCs for areas of continued odour complaints such as Mr. Ron Jones' office if they persist

4.4 Common Indoor Air Pollutants

Results of sampling for common indoor air pollutants are summarized below in Table V.

TABLE V
Summary of Common Indoor Air Pollutants
Enersource Hydro Mississauga
3240 Mavis Rd, Mississauga, ON

Contaminant	Sampling Location	Concentration (ppm)
Ozone (O_3)	Ms.Brenda Checanis cubicle	< 0.025
Nitrogen Oxides (NO_x)	Human Resources area	< 0.04
Sulphur Dioxide (SO_2)	Purchasing Department	< 0.05
Formaldehyde (CH_2O)	Mr. Ron Jones office	< 0.05

As presented in Table V, based on grab sampling conducted in selected representative locations, common indoor air pollutants (formaldehyde, nitrogen dioxide, ozone, and sulphur dioxide) were not detected in samples collected and were within acceptable IAQ guidelines. At these concentrations, these chemicals are not expected to cause any negative health effects for the occupants.

5.0 CONCLUSIONS AND RECOMMENDATIONS

Based on the air sampling results and observations made on the day of assessment, the following conclusions and recommendations can be made:

Visual Inspection of Office Spaces and AHUs

- Sporadic black streaks or smudges were noted near air supply with the Mechanic Office and Trades Training Area (Appendix I, Photograph 2). The presence of black streaks on air supply diffusers indicate an event characterized by the supply of insufficiently filtered air.
    - Supply air diffusers, return grills and ceiling tiles identified to have particulate accumulation should be cleaned. In the event that the problem persists within an area, the source of particulate accumulating on these surfaces should be identified and rectified. Overall, it is important to replace filters regularly within the HVAC system to optimize performance and reduce dust particulate levels within tenant spaces.
- Minor deficiencies included a couple of damaged ceiling tiles and water stained tiles observed in Mechanic Office, Mr. Sam Ramtahal office and Mr. J. P's office. It is recommended that damaged and water stain tiles be replaced as part of regular maintenance. (Appendix 1, Photograph 1, 3, 4)
    - An intact ceiling plenum serves as a path for room air to return to the air handling units. Missing and damaged ceiling tiles may disrupt the flow of return air and reintroduce air in the occupied space without being properly filtered and conditioned. As a part of general maintenance activities, deficiencies noted should be rectified by replacing all deficient ceiling tiles (physically damaged or water-damaged) and adjusting poorly fit ceiling tiles to ensure the efficient operation of the HVAC system as intended.
    - Water-damaged ceiling tiles indicate past or present water leakage, an undesirable condition recognized to promotion of mould growth on affected surfaces. The

underlying cause of the water infiltration onto the surface of the tiles should be identified and rectified

- It is recommended that cleaning of Roof Top Units (RTUs) should be performed on a regular basis to prevent the accumulation of dust and debris. RTU #1 and RTU# 4 and RTU# 11 panel insulation were deteriorated. The overall condition of filters was low to heavy dust loading (Appendix I, Photograph 5, 6, and 7).
    - Saturated filters could potentially cause undue stress on the air-handling unit by forcing the fan unit to work harder than necessary. Saturated filters could also serve as a breeding ground for bacteria and fungi and a source of volatile organic compounds. Filters should be changed as part of regular maintenance activities in accordance with ASHRAE Standard 62.1-2007
- High occupant density was observed on the Customer Service Department and Purchasing Department.
    - The ASHRAE Standard 62.1-2007 provides a guideline level for occupant density in office spaces of 5 individuals per 1,000 square feet, established to promote good indoor air quality.
- Improperly maintained air handling units (AHUs) not only affect the energy consumption efficiency of the units, but also adversely affect the indoor air quality (IAQ) of a building. It is recommended that a professionally developed preventative maintenance program be developed, implemented and monitored. Generally, a preventive maintenance program including periodic inspection and cleaning of air handling units is required in order to maintain them in adequate operating condition. The U.S. National Air Duct Cleaners Association (NADCA) *Standard ACR 2005 – Assessment, Cleaning, and Restoration of HVAC Systems* recommends periodic HVAC cleanliness inspection" of air handling units (1 year), supply ductwork (2 years) and return/exhaust ductwork (2 years). In addition, according to the ASHRAE Standard 62.1-2007, the HVAC system should be operated and maintained at a minimum in accordance with the provisions of this Standard as outlined in Table 8-1 attached in Appendix IV
- The introduction of fresh air to an occupied space allows the dilution of contaminants and odours generated indoors by humans, interior furnishings, office equipment, cleaning agents, live plants, and other indoor sources. It is recommended that Enersource Hydro Mississauga explore options (natural ventilation or mechanical ventilation) to introduce additional fresh air in areas where elevated carbon dioxide (CO_2) and TVOC levels were observed.

Thermal and IAQ Parameters

- Temperature levels ranged between 22.4 and 27.0 ˚C among all locations tested. The majority of the temperature readings were within the ASHRAE guideline range between 22.5-26.0 ^{o} C for the summer season and were acceptable. It is recommended that the temperature controls be adjusted such that a temperature reading between 22.5 – 26.0 ^{o} C is maintained in all locations during normal business hours in the summer months. The ASHRAE temperature guidelines are designed to be acceptable for the majority (approximately 80 %) of occupants

- Relative humidity (% RH) levels ranged between 39.3 and 73.2 %. For all office locations tested with an average relative humidity of 50.5 % for the morning measurements and 50.6 % for the afternoon. The majority of the relative humidity measurements were within the ASHRAE guideline for relative humidity of 20% to 60% and acceptable.

    - High humidity levels can result in condensation within the building structure and on interior or exterior surfaces, and subsequent development of fungal growth. In order to prevent development of microbial contamination relative humidity must be maintained below 60%, as recommended by ASHRAE.

- Carbon dioxide (CO_2) levels ranged between 423 and 1678 ppm for all locations tested throughout the sampling period with average concentrations of 886.9 ppm in the morning and 855.4 ppm in the afternoon (Graph 3, Appendix II). The majority of the CO_2 measurements collected in the office environments were well below the ASHRAE guideline CO_2 concentration of 937 ppm (a concentration of 600 ppm above the measured average outside CO_2 concentration of 337 ppm) and acceptable. The CO_2 concentration exceeded the IAQ guideline in the Accounting Office, Finance Department, IT Department and Customer Service Department, suggesting that an inadequate amount of fresh air is being provided to these areas. It is recommended that the amount of fresh air to be increased to reduce the effect of build-up CO_2 levels.

- Carbon monoxide (CO) concentrations ranged from 0 ppm to 1.9 ppm in all sample locations tested, which is well below the ASHRAE guideline maximum CO concentration of 9 ppm.

- Particulate matter (PM_{10}) levels ranged from 4 to 144 µg/m^3 for all locations tested, with an average concentration of 21.4 µg/m^3 in the morning and 19.5 µg/m^3 in the afternoon. Majority of the particulate matter readings remained relatively constant and below the respective WHO recommended 24-hour guideline value of 50 µg/m^3 (Graph 5, Appendix II). However, particulate matter (PM_{10}) levels in the Store Office (99 µg/m^3 (morning)) and

Sabrina Scot cubicle (114 µg/m^3 (morning)) exceeded WHO IAQ guideline. High levels in Store Office may be due to motor vehicle activities in Warehouse and Garage in the morning.

- TVOC levels ranged between 1 and 440 ppb for all locations tested on the survey date. The majority of the TVOC readings were within the *Comfort Range* (<90 ppb) as established by the Commission of the European Communities and occupants are unlikely to experience discomfort (Graph 6, Appendix II). TVOC levels in some areas within the North Tower 2nd floor, Human Resources, Customer Service and Stores Area during the morning and afternoon sessions (95 – 440 ppb) were at the low end of the *Multifactorial Exposure Range*. Within the *Multifactorial Exposure Range* (90 - 1300 ppb), sensitive or susceptible individuals may experience irritation or discomfort if other IAQ parameters like temperature, relative humidity, or particulate levels are not within their respective recommended ranges. High level of TVOC within the North Tower 2nd floor can be attributed to use of hand sanitizer. Nevertheless, all of the measured TVOC concentrations were within the Health Canada target guideline level of 1,000 µg/m^3 (440 ppb).

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  - Open characterization air sampling for VOC is recommended for odour complaints to identify sources.

- No detectable amounts of sulphur dioxide, nitrogen oxides, formaldehyde, or ozone were noted at the locations tested. Concentrations of these gases were below the limits of detection for the method of analysis and were considered acceptable for indoor air quality based on their recommended exposure guidelines.

General

- The contents this report should be made available to the Joint Health and Safety Committee or safety representative.

6.0 LIMITATIONS

In this statement of limitations, the "Client" refers to the persons or entities to whom this report is addressed. "THEM" refers to T. Harris Environmental Management Inc. The "Contract" refers to any general, or project-specific written agreement, including project-specific scope of work documents, executed between THEM and the Client pertaining to the subject matter of this report.

This report is subject to the limitations set out below and any other limitations set out in the body of this report or in the Contract between THEM and the Client.

The investigation and assessment described in this report were conducted in accordance with the Contract agreed upon by the Client in a manner consistent with a reasonable level of care and skill normally exercised by members of the occupational hygiene consulting profession currently practising under similar conditions in the Province of Ontario and observing the code of ethics of the Canadian Registration Board of Occupational Hygienists (CRBOH) and the American Board of Industrial Hygiene (ABIH).

In preparing this report, THEM has relied on information provided by others, including without limitation, information concerning the history and operation of the site, and test results and analyses of other consultants, independent laboratories, or testing services. Except as expressly stated in this report, THEM have not made any independent verification of such information. Findings cannot be extended to portions of the site, which were unavailable for direct observation.

The assessment in this report has been made in the context of regulations which were in force and effect at the time of the assessment and which are specified in this report. The assessment did not take into account any regulations, which were not in effect at the date of the assessments, or any guideline or standard not specified in this report. Regulatory standards do not exist for all materials of a potentially hazardous nature.

The collection of any samples at the site (including the location of samples and the analytical parameters applied to the samples) was undertaken in accordance with the Contract agreed upon by the Client, based upon the information provided to THEM by the Client concerning existing site conditions. Conditions between sample locations (if any) may differ from those indicated in this report.

This report is intended solely for the use or uses specified in this report and/or the Contract. Use of this report for purposes other than those set out in this report and/or the Contract will be at the sole risk of the Client.

Copying of this report except as may be reasonably required for internal use by the Client and any distribution of this report to persons other than the Client in whole or in part, is not permitted without the express written permission of THEM.

This report is for the sole use of the Client. THEM makes no representation or warranty, either expressed or implied, to any third party with regard to this report and the work referred to in this report and expressly disclaims any, and accepts no duty of care to any third party or any responsibility or liability whatsoever to any third party for any loss, expenses, damages (direct, consequential or contingent), fines, penalties, or other harm that may be suffered or incurred by any third party as a result of any use of, any reliance placed upon, or any decision made or actions taken based upon this report or the work referred to herein.

In no event shall THEM be liable for any indirect, incidental, special or consequential damages, or damages from loss of profits, revenue, or use, incurred by either the client or any third party,

whether in an action in tort or contract, even if THEM has been advised of the possibility of such damages. THEM's liability for damages shall in no event exceed the limit of available insurance coverage."

If new information concerning the subject matter of this report arises, THEM should be contacted to re-evaluate the conclusions of this report and to provide amendments as required.

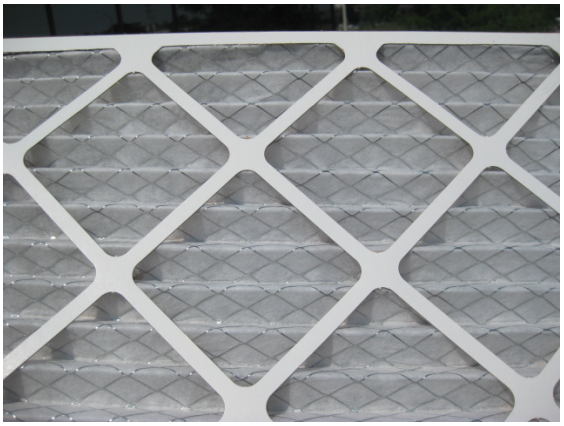
APPENDIX I
SITE PHOTOGRAPHS

Photograph 1. View of broken ceiling tile

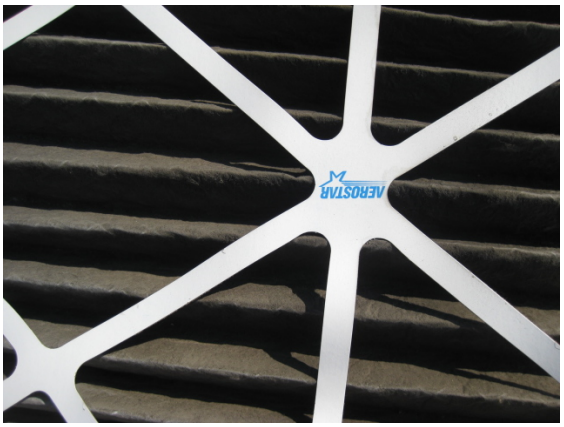
Photograph 2: Dirty air diffuser in the Mechanic Office

Photograph 3: View of water stain on ceiling tile

Photograph 4: View of water stain and damage ceiling tile



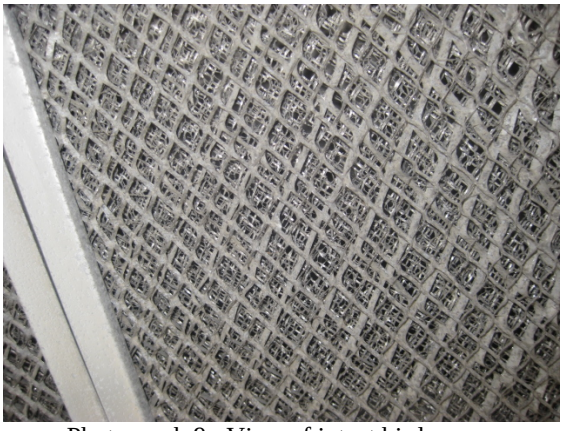
Photograph 5: View of low dust load prefilter



Photograph 6: View of heavy dust loaded prefilter

Photograph 7: View of low dusted polyester prefilter

Photograph 8: Supply fan in good working condition



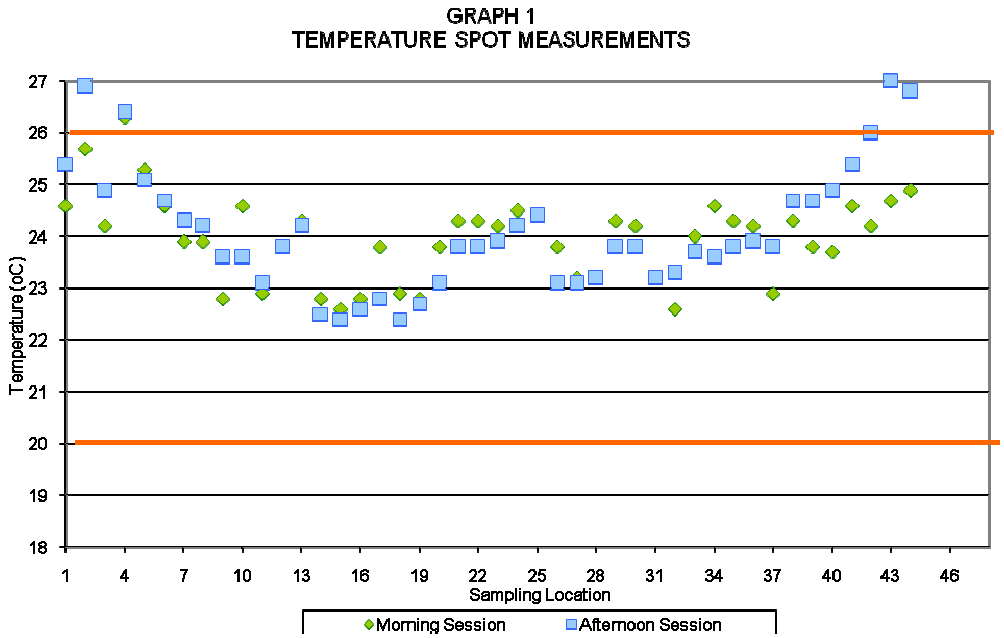
Photograph 9: View of intact bird screen

Photograph 10: View of cooling coils

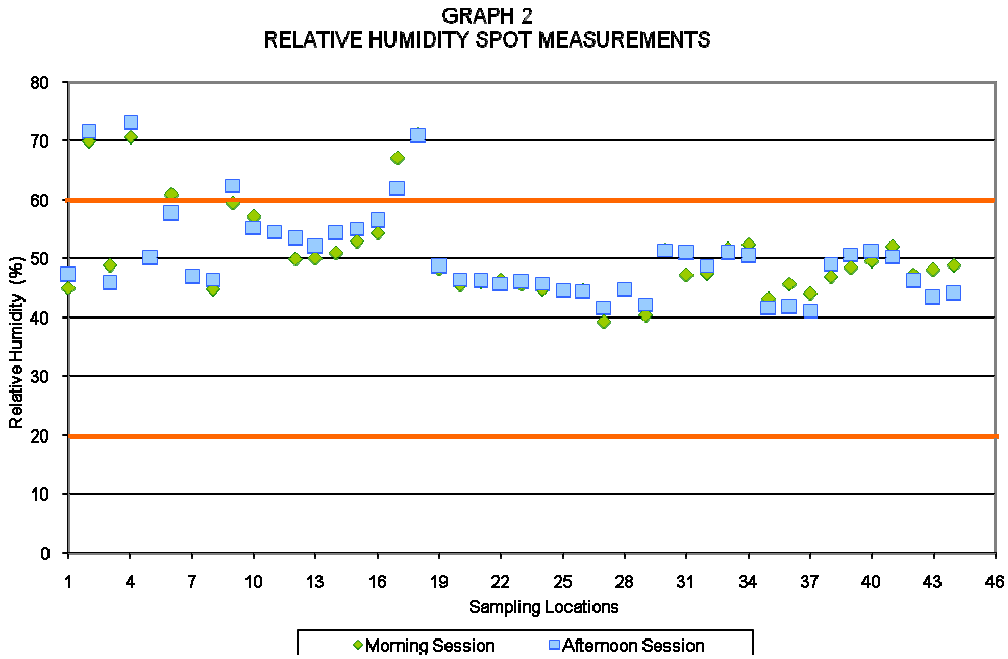
Photograph 11: View of deteriorated insulation panel

Photograph 12: View of dampers of at 60%

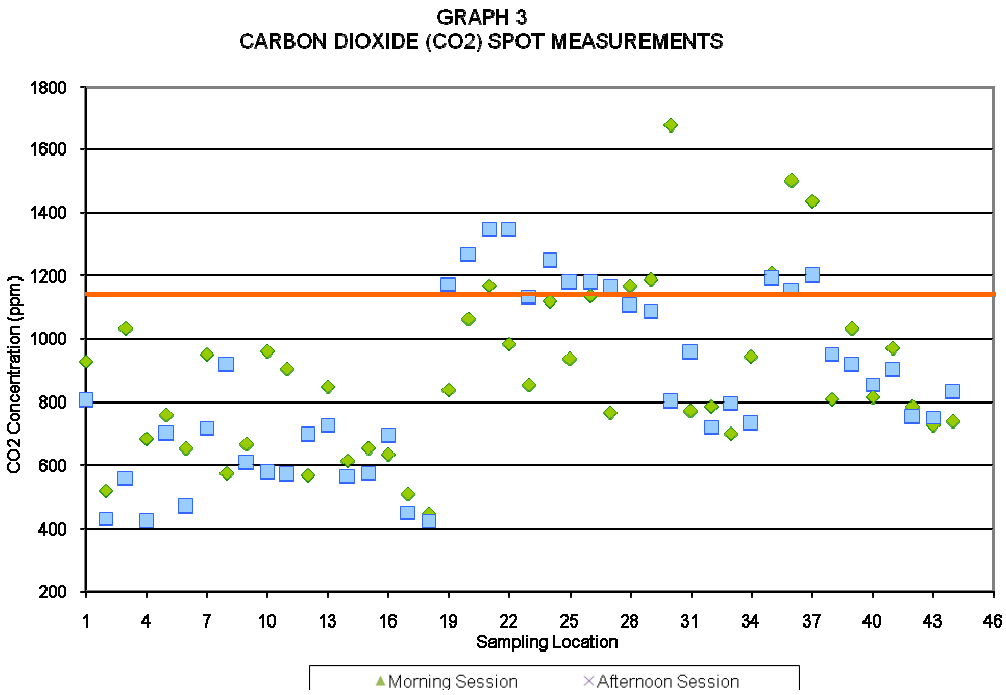
APPENDIX II
IAQ MEASUREMENT DATA AND GRAPHS



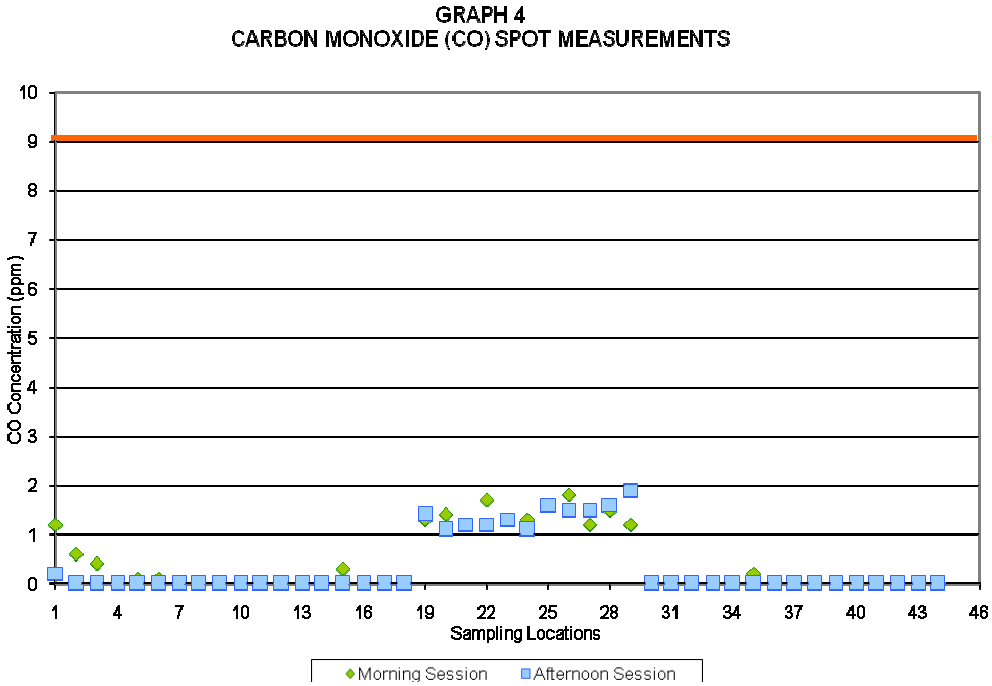
Graph 1: Location-based Temperature Measurements
Based on ASHRAE Guideline 22.5 – 26.0 ˚C (Orange solid lines)



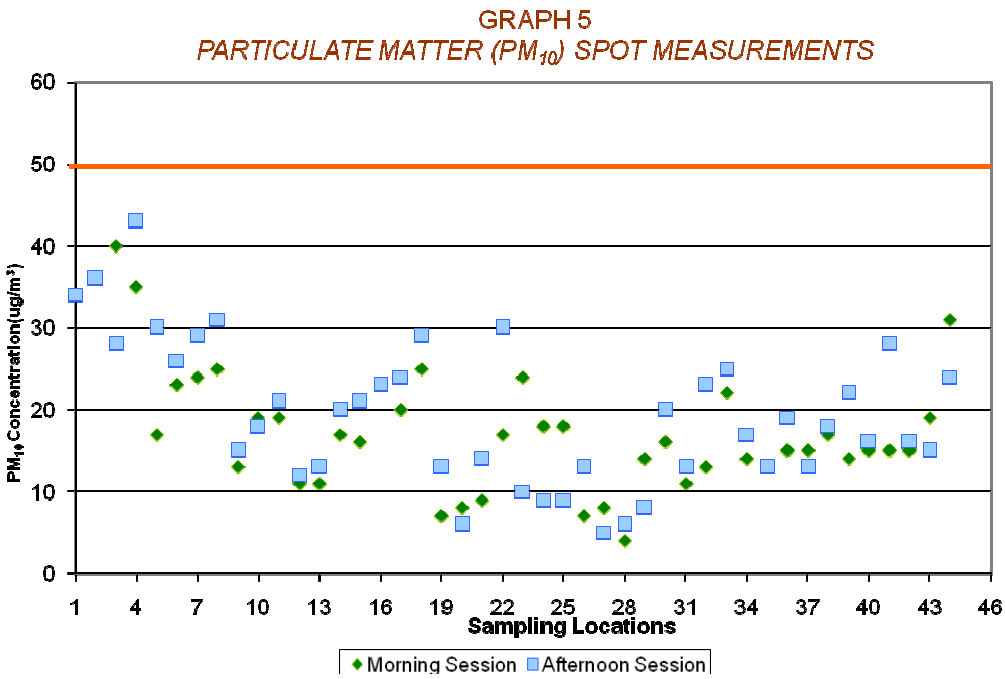
Graph 2: Location-Based Relative Humidity Levels
ASHRAE Design Guideline: 20 % - 60 % (Orange solid lines)



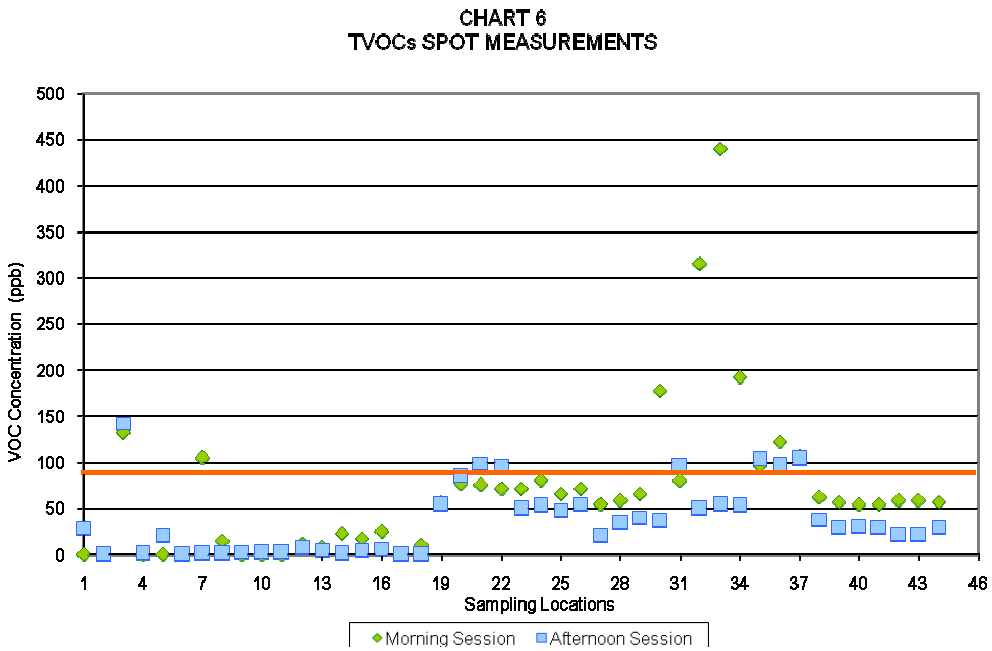
Graph 3: Location-Based Carbon Dioxide Concentrations
ASHRAE Guideline: 1155 ppm guideline level for office spaces (Orange solid line)



Graph 4: Location-Based Carbon Monoxide Concentrations
ASHRAE Guideline: 9-ppm guideline level (Orange solid line)



Graph 5: Location-Based PM_{10} Concentrations
WHO Guideline: 50 µg/m^3 (24 Hour) guideline level (Orange solid line)



Graph 6: Location-Based TVOC Concentrations
Commission of European Communities: 90 ppb guideline level (Orange solid line)

Indoor Air Quality Assessment
Enersource Hydro Mississauga
3240 Mavis Rd, Mississauga, ON

THEM # 13923

TABLE A
Thermal Comfort and Air Quality Parameter Measurements
Enersource Hydro Mississauga
3240 Mavis Rd, Mississauga, ON

Sr.#	Sample Locations		Temp (°C)		RH (%)		CO_2 (ppm)		CO (ppm)		PM_{10} (µg/m^3)		TVOC (ppb)	
			R1	R2	R1	R2	R1	R2	R1	R2	R1	R2	R1	R2
1	STORES	Stores Office	24.6	25.4	45.4	47.3	929	804	1.2	0.2	99	34	0	29
2		Ware House Area	25.7	26.9	70	71.5	519	431	0.6	0	36	36	0	0
3		Ron Jones Office	24.2	24.9	48.9	45.9	1003	559	0.4	0	40	28	133	142
4	GARAGE	Garage	26.3	26.4	70.7	73.2	684	423	0	0	35	43	0	1
5		Trouble room	25.3	25.1	50.4	51.0	759	700	0.1	0	17	30	0	21
6		Mechanic Office	24.6	24.7	61.0	57.7	653	469	0.1	0	23	26	0	0
7	METERING	Kevin Toth Office	23.9	24.3	46.9	46.9	952	717	0	0	24	29	105	1
8		Meter Tech Room	23.9	24.2	44.9	46.5	576	917	0	0	25	31	15	1
9	MAVIS R.	Mavis Room	22.8	23.6	59.5	62.4	666	607	0	0	13	15	0	3
10	SOUTH TOWER 2ND FLOOR	Street Light Stg. Area	24.6	23.6	57.2	55.3	959	577	0	0	19	18	0	2
11		Street Light Area	22.9	23.1	54.6	54.6	903	571	0	0	19	21	0	2
12		Control Room	23.8	23.8	49.9	53.5	570	696	0	0	11	12	12	7
13	SOUTH TOWER 3RD FLOOR	Control R. Judy's Area	24.3	24.2	50.1	52.1	848	727	0	0	11	13	8	5
14		Ramez Hakeem Office	22.8	22.5	51.0	54.4	616	566	0	0	17	20	23	1
15		Joanna Cieniak Office	22.6	22.4	52.9	55.2	653	576	0.3	0	16	21	17	5
16		Sabrina Scot Cubicle	22.8	22.6	54.4	56.5	633	693	0	0	114	23	25	6

Indoor Air Quality Assessment
Enersource Hydro Mississauga
3240 Mavis Rd, Mississauga, ON

THEM # 13923

Sr.#	Sample Locations		Temp (°C)		RH (%)		CO_2 (ppm)		CO (ppm)		PM_{10} (µg/m^3)		TVOC (ppb)	
			R1	R2	R1	R2	R1	R2	R1	R2	R1	R2	R1	R2
17	MIDDLE 2ND FLOOR	Purchasing Area	23.8	22.8	67.3	62.1	508	450	0	0	20	24	1	0
18		Trades Training Area	22.9	22.4	71.3	70.8	445	424	0	0	25	29	11	0
19	ACCOUNTING OFFICES SERVICES	Mail Room	22.8	22.7	48.3	48.7	839	1172	1.3	1.4	7	13	57	54
20		Lyn Parker Area	23.8	23.1	45.5	46.5	1061	1268	1.4	1.1	8	6	77	85
21		John Bonadie Office	24.3	23.8	46.1	46.2	1169	1346	1.2	1.2	9	14	76	99
22		John Yoon	24.3	23.8	46.5	45.8	984	1347	1.7	1.2	17	30	71	95
23	FINANCE	James Macumber	24.2	23.9	45.7	46.0	854	1132	1.3	1.3	24	10	72	50
24		Natalie King	24.5	24.2	44.9	45.8	1120	1274	1.3	1.1	18	9	80	53
25		Hurontario Room	24.4	24.4	44.6	44.7	937	1177	1.6	1.6	18	9	66	48
26		Tou Project Room	23.8	23.1	44.6	44.5	1136	1177	1.8	1.5	7	5	72	55
27	INFORMATIN TECH. (IT)	Comp.Trg. Room	23.2	23.1	39.3	41.7	766	1164	1.2	1.5	8	5	54	41
28		Noaman Afzal	23.2	23.2	44.8	44.9	1167	1104	1.5	1.6	4	6	59	34
29		James Zietsma	24.3	23.8	40.4	42.2	1187	1085	1.2	1.9	14	8	66	40

Indoor Air Quality Assessment
Enersource Hydro Mississauga
3240 Mavis Rd, Mississauga, ON

THEM # 13923

SR#	Sample Locations		Temp (°C)		RH (%)		CO_2 (ppm)		CO (ppm)		PM_{10} (µg/m^3)		TVOC (ppb)	
			R1	R2	R1	R2	R1	R2	R1	R2	R1	R2	R1	R2
30	NORTH TOWER 2ND FLOOR	Main Lobby	24.2	23.8	51.6	51.4	1678	801	0	0	16	20	178	36
31		Executive Area	23.2	23.2	47.3	51.0	772	956	0	0	11	13	80	89
32		Carla DiFonia	22.6	23.3	47.5	48.8	786	720	0	0	13	23	316	50
33		Bernie Haines	24.0	23.7	51.7	51.0	701	796	0	0	22	25	440	54
34	HR	Ramla Passi	24.6	23.6	52.5	50.5	944	733	0	0	14	17	192	53
35	CUSTOMRT SERVICE	Nichole Johnson	24.3	23.8	43.2	41.7	1207	1190	0.2	0	13	13	96	103
36		Adriana Fernandes	24.3	23.9	45.8	41.8	1500	1156	0	0	15	19	122	97
37		Joan Nemec	22.9	23.8	44.1	41.2	1435	1200	0	0	15	13	106	104
38	NORTH TOWER 3RD FLOOR	Arnel Colmenar	24.3	24.7	46.9	49.1	809	952	0	0	17	18	62	38
39		Kim Nugent	23.8	24.7	48.5	50.7	1032	916	0	0	14	22	57	30
40		James Berry	23.7	24.9	49.7	51.2	814	856	0	0	15	16	54	31
41		Port Credit Room	24.6	25.4	52.1	50.4	969	901	0	0	15	28	55	30
42		Brenda Checanis	24.2	26.0	47.4	46.2	785	752	0	0	15	16	59	27
43		Amy Hime	24.7	27.0	48.2	43.4	726	751	0	0	19	15	59	22
44		J.P office	24.9	26.8	49.0	44.1	739	831	0	0	31	24	57	30
45		**OUTDOOR**	**25.6**		**73.1**		**554**		**0**		**51**		**0**	

Values in red indicate IAQ guidelines

APPENDIX III
TABLE 8-1 - ASHRAE STANDARD 62.1-2007

TABLE 8-1 Minimum Maintenance Activity and Frequency

Item	Activity Code	Minimum Frequency*
Filters and air-cleaning devices	A	According to O&M Manual
Outdoor air dampers and actuators	B	Every three months or in accordance with O&M Manual
Humidifiers	C	Every three months of use or in accordance with O&M Manual
Dehumidification coils	D	Regularly when it is likely that dehumidification occurs but no less than once per year or as specified in the O&M Manual
Drain pans and other adjacent surfaces subject to wetting	D	Once per year during cooling season or as specified in the O&M Manual
Outdoor air intake louvers, bird screens, mist eliminators, and adjacent areas	E	Every six months or as specified in the O&M Manual
Sensors used for dynamic minimum outdoor air control	F	Every six months or periodically in accordance with O&M Manual
Air-handling systems except for units under 2000 cfm (1000 L/s)	G	Once every five years
Cooling towers	H	In accordance with O&M Manual or treatment system provider
Floor drains located in plenums or rooms that serve as air plenums	I	Periodically according to O&M Manual
Equipment/component accessibility	J	
Visible microbial contamination	K	
Water intrusion or accumulation	K	

ACTIVITY CODE:
A Maintain according to O&M Manual.
B Visually inspect or remotely monitor for proper function.
C Clean and maintain to limit fouling and microbial growth.
D Visually inspect for cleanliness and microbial growth and clean when fouling is observed.
E Visually inspect for cleanliness and integrity and clean when necessary.
F Verify accuracy and recalibrate or replace as necessary.
G Measure minimum quantity of outdoor air. If measured minimum airflow rates are less than 90% of the minimum outdoor air rate in the O&M Manual, they shall be adjusted or modified to bring them above 90% or shall be evaluated to determine if the measured rates are in conformance with this standard.
H Treat to limit the growth of microbiological contaminants.
I Maintain to prevent transport of contaminants from the floor drain to the plenum.
J Keep clear the space provided for routine maintenance and inspection around ventilation equipment.
K Investigate and rectify.

* Minimum frequencies may be increased or decreased if indicated in the O&M Manual.

CBRE
CB RICHARD ELLIS

VALUATION REPORT
OF AN
INDUSTRIAL PROPERTY

Located at
3214 & 3240 Mavis Road
Mississauga, ON
CBRE File No. A10.271

VALUATION DATE
November 2, 2010

PREPARED FOR

JP Michaud, P.Eng.
Senior Manager, Substations and Facilities
Enersource Corporation
3214 & 3240 Mavis Road
Mississauga, ON
L5C 3K1

PREPARED BY
Dan Hayes
and
Michael Fairfield, AACI, P.App.
of

CB RICHARD ELLIS LIMITED, REALTOR
VALUATION & ADVISORY SERVICES
2001 Sheppard Avenue East, Suite 300,
Toronto, Ontario M2J 4Z8

CBRE
CB RICHARD ELLIS

Our Ref.: A10-164

January 19, 2011
JP Michaud, P.Eng.
Senior Manager, Substations and Facilities
Enersource Corporation
3214 & 3240 Mavis Road
Mississauga, ON
L5C 3K1

VALUATION & ADVISORY SERVICES
2001 Sheppard Avenue E.
Suite 300
Toronto, Ontario
M2J 4Z8

Telephone: (416) 494-0600
Facsimile: (416) 494-8806
www.cbre.ca

Dear Mr. Michaud:

RE: 3214 & 3240 Mavis Road, MISSISSAUGA, ONTARIO

In accordance with your request for an estimate of the market value of the within described real property, we have prepared and submit herein our findings. The subject property is comprised of a single tenant industrial building totalling 125,000 square feet of gross floor area, including 70,000 square feet of office area, situated on a 10.22 acre site. The property is occupied by Enersource Corporation.

This short narrative report describes the method and approaches to value employed and contains some of the data gathered in our investigation. After careful consideration, it is our opinion that the estimated market value of the subject, as of November 2, 2010, is:

SIX MILLION EIGHT HUNDRED SEVENTY FIVE THOUSAND DOLLARS
($6,875,000)

The above value is predicated on an exposure time of approximately 6-9 months and assumes sale on cash to vendor basis. Your attention is invited to the following report, which contains the data, analyses, assumption and limiting conditions upon which the estimated value is based. The fieldwork from which the report has been prepared is retained in our files. Any enquiries are welcome.

Respectfully submitted,
CB Richard Ellis Limited Real Estate Brokerage

Michael Fairfield, AACI, P.App.
Associate Director

Dan Hayes
Associate Director

Participant	Business Unit	Description	Division	# of employees in admin building	# of employees in Ops building	10310	10320	10330	10341	10344	10360	10365	10510	10562	10571	10601	10606	10607	10608	10610	10620	10630	10640	10661	10663	10666	10672	10676	10681	10683	10690	10722	10723	10750	20110	20120	20130	20150	20160	20210	20421	20770	34140	34655
			Division			Customer Care	Customer Care	Customer Care	Customer Care	Customer Care	Strategic Projects	Strategic Projects	IT	IT	IT	Executive & Support Group	Strategic Projects	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Engineering & Operations	Executive & Support Group	Executive & Support Group	Executive & Support Group	Executive & Support Group	Executive & Support Group	Human Resources	Finance	Finance	EHMS	EHMS
			Description			Cust Serv & Reg Affairs Admin	Regulatory Affairs	Settlements	Customer Accounts	Billing	Metering	Smart Meters	Information Services Admin	Computer Operations	Engineering & Asset Systems	Enersource HM Executives	Conservation & Demand Mgt(CDM)	System Operations Admin	Distr & Standards Admin	Enersource HM Admin	Control System	Corporate Records & Mapping	Grounds & Buildings	Substation Operations	System Planning	O/H Repair	Cable Locates	U/G Mtnce, Rep. & Burnoffs	O/H Maintenance & Repairs	Tree Trimming	Garage	Overhead Construction	I/C Cust Proj/Inspections	Stores	Board of Directors	Chief Executive Officer	Government Relat. & Marketing	Safety	Legal	Human Resources	Finance	Purchasing	Services	Streetlighting
			Business Unit			10310	10320	10330	10341	10344	10360	10365	10510	10562	10571	10601	10606	10607	10608	10610	10620	10630	10640	10661	10663	10666	10672	10676	10681	10683	10690	10722	10723	10750	20110	20120	20130	20150	20160	20210	20421	20770	34140	34655
Sonja P	10310	Cust Serv & Reg Affairs Adm	Customer Care	3	0	0	4	4	3	2	2	3	3	3	5	4	4	4	4	4	4	5	4	5	5	5	5	5	5	4	5	5	3	4	5	4	4	4	4	4	4	4	5	4
Gia D	10320	Regulatory Affairs	Customer Care	3	0	3	0	3	3	3	2	2	3	4	4	2	2	4	5	5	5	5	4	5	3	5	5	5	5	5	5	5	5	5	4	2	2	3	3	3	2	4	4	5
Sonja P	10330	Settlements	Customer Care	7	0	2	3	0	3	2	2	3	2	3	4	2	3	2	3	3	3	4	4	5	2	4	5	5	5	5	4	5	4	3	4	3	2	2	3	3	2	3	4	4
Pam S	10341	Customer Accounts	Customer Care	27	0	3	4	4	0	2	2	3	3	3	5	4	4	4	4	4	4	5	4	5	5	5	5	5	5	4	5	5	3	4	5	4	4	4	4	4	4	4	5	4
Rob M	10344	Billing	Customer Care	24	0	2	4	2	1	0	1	1	1	1	4	3	3	4	4	4	3	4	4	5	5	3	5	3	5	5	3	3	3	5	5	4	4	4	4	4	2	5	5	4
Tom W	10360	Metering	Strategic Projects	12	0	2	3	2	3	2	0	2	2	3	4	2	3	2	3	3	3	4	4	5	2	4	5	5	5	5	4	5	4	3	4	3	2	2	3	3	2	3	4	4
Tom W	10365	Smart Meters	Strategic Projects	5	0	2	3	2	3	2	2	0	2	3	4	2	3	2	3	3	3	4	4	5	2	4	5	5	5	5	4	5	4	3	4	3	2	2	3	3	2	3	4	4
David C	10510	Information Services Admin	IT	9	0	2	4	4	2	3	2	2	0	1	3	2	3	3	2	3	4	4	4	2	2	2	3	2	2	4	3	3	3	2	5	4	4	4	5	3	2	2	3	3
Rod	10562	Computer Operations	IT	14	0	2	2	2	2	2	2	2	1	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	4	3	2	2	2	2	2	2	2	2
Amy H	10571	Engineering & Asset Systems	IT	8	0	5	4	4	4	5	4	4	2	3	0	3	4	4	2	4	2	2	4	3	3	2	2	2	2	5	4	2	2	3	5	4	4	4	4	3	3	3	3	3
Dan P	10601	Enersource HM Executives	Executive & Support Group	3	0	2	2	3	3	3	3	3	2	3	3	0	2	3	3	2	3	3	3	3	3	4	4	4	4	4	4	4	3	4	3	2	2	2	3	3	2	4	5	5
Tom W	10606	Conservation & Demand Mgt	Strategic Projects	7	0	2	3	2	3	2	3	3	2	3	4	2	0	2	3	3	3	4	4	5	2	4	5	5	5	5	4	5	4	3	4	3	2	2	3	3	2	3	4	4
JPM	10607	System Operations Admin	Engineering & Operations	0	8	4	5	5	4	4	4	4	3	3	3	4	5	0	2	2	2	2	4	2	3	4	4	4	4	4	3	3	4	4	5	5	4	3	4	3	3	3	4	4
Doug M	10608	Distr & Standards Admin	Engineering & Operations	0	9	4	5	5	4	3	4	4	4	4	3	5	5	2	0	2	2	3	5	4	3	2	3	2	2	3	4	3	3	4	5	5	4	4	4	4	4	3	5	3
RR	10610	Enersource HM Admin	Engineering & Operations	1	0	3	4	4	5	4	4	5	4	4	4	2	3	2	2	0	3	3	4	4	2	4	5	4	4	4	4	2	2	4	4	3	4	2	4	3	3	4	5	4
Paul S	10620	Control System	Engineering & Operations	0	15	2	3	3	2	2	2	1	2	1	1	4	4	2	2	2	0	2	4	2	2	2	2	2	2	2	4	2	2	4	5	4	4	2	4	4	4	4	3	2
Amy H	10630	Corporate Records & Mappin	Engineering & Operations	12	0	5	4	4	4	5	4	4	2	3	2	3	4	4	2	4	2	0	4	3	3	2	2	2	2	5	4	2	2	3	5	4	4	4	4	3	3	3	3	3
JPM	10640	Grounds & Buildings	Engineering & Operations	0	4	5	5	5	5	4	4	4	3	2	5	3	5	2	4	3	4	5	0	4	5	4	4	5	4	4	2	5	5	2	5	5	4	3	5	4	3	3	5	4
JPM	10661	Substation Operations	Engineering & Operations	0	15	4	5	5	5	4	4	5	5	3	3	5	5	2	3	4	2	3	4	0	4	3	4	4	3	4	3	4	5	2	5	5	4	3	5	4	3	4	4	4
Paul S	10663	System Planning	Engineering & Operations	6	0	4	4	4	4	4	4	5	4	4	3	4	3	3	3	4	3	3	4	3	0	4	4	4	3	4	4	3	2	4	5	5	4	4	4	4	4	4	3	4
Doug M	10666	O/H Repair	Engineering & Operations	0	13	4	5	5	4	4	4	5	5	4	4	5	5	3	2	3	1	3	5	3	4	0	4	2	2	3	3	4	4	2	5	5	4	3	5	5	5	5	5	3
Bob K	10672	Cable Locates	Engineering & Operations	0	2	4	5	5	4	5	4	5	4	4	3	5	5	4	4	5	4	3	5	4	5	4	0	4	4	4	4	4	4	4	5	5	4	4	4	4	5	4	5	4
Doug M	10676	U/G Mtnce, Rep. & Burnoffs	Engineering & Operations	0	10	4	5	5	5	4	4	5	5	4	4	5	5	3	3	2	2	3	5	3	4	2	2	0	2	4	3	4	4	2	5	5	4	3	5	5	5	5	5	4
Doug M	10681	O/H Maintenance & Repairs	Engineering & Operations	0	32	incl 22 appre	5	5	5	4	4	5	5	4	4	5	5	3	2	3	2	3	5	3	4	2	2	2	0	3	3	3	3	2	5	5	4	3	5	5	5	5	5	3
Doug M	10683	Tree Trimming	Engineering & Operations	0	4	4	5	5	5	5	4	5	5	5	5	5	5	3	3	3	2	5	5	4	4	2	4	3	2	0	3	3	4	3	5	5	3	3	5	5	5	5	5	5
Bob K	10690	Garage	Engineering & Operations	0	8	4	5	5	5	5	3	5	4	4	4	3	5	4	4	4	3	4	3	3	4	3	3	3	3	3	0	3	3	3	5	4	4	3	4	3	4	3	3	3
Bob K	10722	Overhead Construction	Engineering & Operations	10	20	4	5	5	4	4	4	4	3	4	3	3	5	4	3	2	2	3	3	3	3	3	2	4	4	3	3	0	3	2	5	3	4	2	4	4	2	2	4	3
Dal C	10723	I/C Cust Proj/Inspections	Engineering & Operations	12	14	3	3	4	3	4	2	3	5	5	4	4	4	3	3	2	2	3	4	4	2	4	3	4	4	4	5	4	0	3	5	5	4	3	4	4	3	3	4	4
Doug M	10750	Stores	Engineering & Operations	0	7	5	5	5	5	5	4	3	5	4	5	5	5	5	2	3	3	5	4	2	5	2	4	2	2	3	3	3	4	0	5	5	5	4	5	5	3	2	3	3
Dan P	20110	Board of Directors	Executive & Support Group																																0									
Dan P	20120	Chief Executive Officer	Executive & Support Group	9	0																															0								
Karen R	20130	Government Relat. & Marketi	Executive & Support Group	4	0	2	3	4	2	3	3	3	3	3	4	2	2	4	3	4	3	4	4	3	4	3	4	3	3	3	4	3	4	4	4	2	0	3	4	3	3	4	5	4
Bernie H	20150	Safety	Executive & Support Group	2	1	3	4	4	4	4	3	3	4	4	4	2	4	4	4	2	3	4	3	3	4	3	4	3	3	3	3	3	3	3	4	3	4	0	4	2	3	3	3	3
Carla D	20160	Legal	Executive & Support Group	1	0	4	3	4	5	4	4	4	4	4	4	2	3	4	4	4	5	5	4	4	5	5	5	5	5	5	5	5	5	4	2	2	4	4	0	4	3	4	4	4
Linda A	20210	Human Resources	Human Resources	4	0	3	4	4	3	3	3	3	3	4	3	3	4	4	3	4	4	4	3	4	4	4	4	4	4	4	4	4	4	4	3	3	4	2	4	0	2	4	4	4
James M	20421	Finance	Finance	27	0	3	2	3	3	2	3	3	3	3	3	3	3	4	4	3	4	3	4	4	3	4	4	4	4	4	4	2	4	3	4	2	3	3	3	2	0	3	3	3
Ramona H	20770	Purchasing	Finance	5	0	4	4	4	5	5	4	4	4	4	4	3	4	3	3	3	4	5	4	4	3	3	5	3	3	5	4	3	3	3	5	4	4	3	4	4	3	0	3	3
Andrew B	34140	Services	EHMS	6	4	5	4	5	5	5	5	5	3	3	2	4	5	5	4	4	3	3	4	5	5	5	3	4	4	4	3	4	4	2	5	3	4	2	4	3	2	3	0	3
Andrew B	34655	Streetlighting	EHMS	0	13	5	4	5	5	5	5	5	3	3	2	4	5	5	4	4	3	3	4	5	5	5	3	4	4	4	3	4	4	2	5	3	4	2	4	3	2	3	3	0
				221	179	400																																						

0 Your department
1 Work with hourly
2 Work with daily
3 Work with weekly
4 Workwith rarely
5 Never work with

	Operations
	Administr
	mix

Administration Building Forecast

Revision Date 18-Aug-11

Space Forecast Modeling Summary

	Group or Department Name:	Current Location:	Existing	2011 Occupancy	Forecast at Move-in	Move-in Occupancy	Forecast at Move-in + 5 years	Forecast Occupancy +5yrs
1	Health, Safety & Security	10150	540	0	540	0	540	0
2	Customer Care - Service & Reg Affairs Admin	10310	1,707	7	1,429	3	1,515	4
3	Customer Care - Regulatory Affairs	10320	298	1	547	3	547	3
4	Customer Care - Settlements	10330	536	5	622	6	622	6
5	Customer Care - Customer Accounts	10341	4,020	45	4,020	45	5,079	52
6	Customer Care - Billing	10344	1,197	11	806	9	806	9
7	Strategic Projects - Metering	10360	0	0	0	0	0	0
9	IT - Information Services Admin	10510	4,621	26	4,621	27	4,794	29
10	IT - Computer Opertions	10562	1,847	9	1,847	9	1,933	10
12	Executive & Support Group - Enersource HM Executives	10601	959	3	959	3	959	3
13	Strategic Projects - Conservation & Demand Mgt	10606	1,015	10	1,015	10	1,015	10
19	Facilities	10640	635	0	635	0	635	0
31	Executive & Support Group - Chief Executive Officer	20120	3,731	4	4,647	8	4,647	8
32	Executive & Support Group - Government Relat. & Marketing	20130	1,415	4	1,145	4	1,145	4
33	Internal Audit & Enterprise Risk	20170	788	3	788	3	788	3
34	Human Resources	20210	1,922	5	1,922	5	2,152	6
35	Finance	20421	4,047	29	4,863	33	4,949	34
36	Purchasing	20770	1,133	8	1,133	8	1,133	8
39	Common Areas	Common Areas	33,365	0	35,269	0	35,269	0
	Sub Total - Required Area		63,778		66,808		68,527	
	Forecast Program Churn/Open Area	5%	3,189		3,340		3,426	
	Forecast Building Features	3%	1,913		2,004		2,056	
	Forecast Building R/U Factor	12%	8,266		8,658		8,881	
	Total Office Space Rental Requirement		**77,145**	**170**	**80,810**	**176**	**82,891**	**189**

Service Quality and Reliability Performance

Enersource monitors and reports service quality indicators as required in Chapter 15 of the Ontario Energy Board's (the "Board") 2006 Electricity Distribution Rate Handbook ("2006 EDRH"), and in accordance with Chapter 7 of the Distribution System Code ("DSC").

As of January 1, 2009 Enersource began tracking nine of the Board's customer service indicators and three service reliability indices on a monthly basis. For 2011 reporting, an additional electricity service quality requirement ("ESQR") was added for reconnection standards. Results are reported internally on a monthly basis. Reports are provided to the Board annually in accordance with the 2006 EDRH, and in accordance with the DSC amendments that were most recently issued in April 2011.

Enersource customer service and reliability results from 2009 to 2011 are shown at Exhibit 2 Tab 3 Schedule 1 Appendix 1 and are discussed below.

Customer Service Indicators

The current customer service indicators are as follows:

1) Connection of New Services: low voltage service (<750 volts)
2) Connection of New Services: high voltage service (>750 volts)
3) Appointment Scheduling
4) Appointments Met
5) Rescheduling a Missed Appointment
6) Telephone Accessibility
7) Telephone Call Abandon Rate
8) Written Response to Inquiries
9) Emergency Response

10) Reconnection Standards

Note that Enersource tracks urban emergency responses, as rural responses are not applicable.

Enersource has met and or exceeded the minimum Board standards for all but one of the customer service quality indicators over the historical period as illustrated in Table 1 of Appendix 1 of this exhibit. The sole exception is the rescheduling of missed appointments indicator in 2011.

Service Reliability Indicators

The three service reliability indicators provided annually to the Board are commonly referred to by their acronyms, SAIDI, SAIFI and CAIDI. Each is defined and described below.

i) System Average Interruption Frequency Index ("SAIFI"):

SAIFI is an indicator of the number of interruptions each customer experiences annually. It is a measure of the average number of times which distribution customers served by Enersource were interrupted in the year.

ii) System Average Interruption Duration Index ("SAIDI"):

SAIDI is an indicator of system reliability that expresses the average total length of outage customers experience in the year. It is a measure of the average number of hours that distribution customers served by Enersource were without power in the year.

iii) Customer Average Interruption Duration Index ("CAIDI"):

CAIDI is an indication of the speed at which power is restored. It is a measure of the average interruption duration (in hours) of distribution customers who were interrupted during the year.

The above three reliability indices measure all interruptions caused by planned and unplanned interruptions of one minute or more.

The Board's EDRH states that a distributor is required to monitor reliability indices monthly and report to the Board on an annual basis. The handbook also states that a distributor should, at a minimum, remain within the range of its historical (three-year) performance. The monitoring and reporting of service reliability indices is intended to encourage distributors to maintain or improve the existing service reliability performance of its electrical distribution system.

2011 Reliability Results

The reliability indices for 2009 through 2011 are provided in Appendix 1 of this exhibit. Appendix 1 Table 2 provides the reliability indices including all outages. Appendix 1 Table 3 provides the reliability indices adjusted to exclude the outages caused by loss of supply (also known as cause code 2).

Enersource's 2011 SAIDI and SAIFI indices are outside of the three-year historical range, but the CAIDI index is within the historical range. This can be seen on Figures 1 to 6 below which show the 2011 reliability results graphically, including clear identifiers of the historical range over the three-year period from 2008 to 2010.

SAIDI and SAIFI for 2011 indicate the cumulative statistics of each month and CAIDI indicates the statistics at the end of each month.

Figure 1: Enersource 2011 SAIDI Results

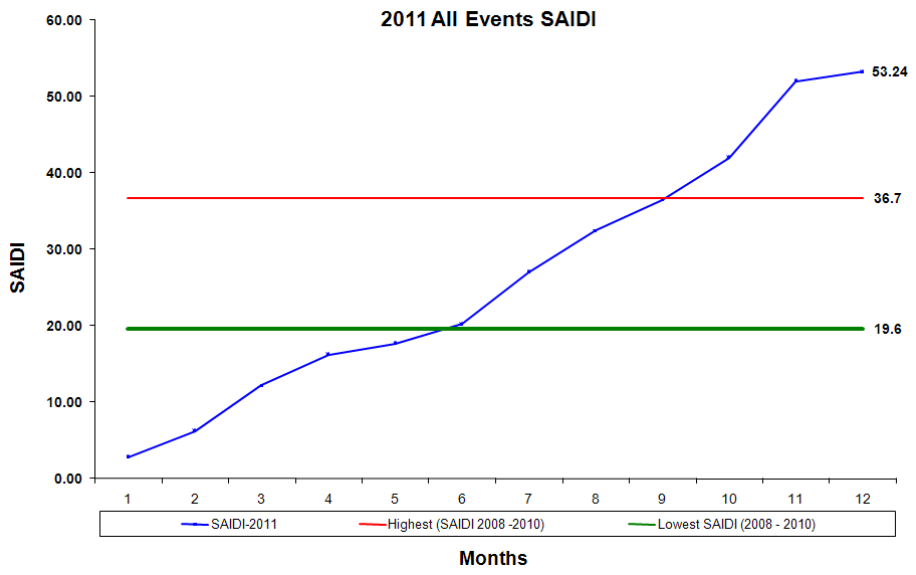


Figure 2: Enersource 2011 SAIDI Results – Excluding Loss of Supply

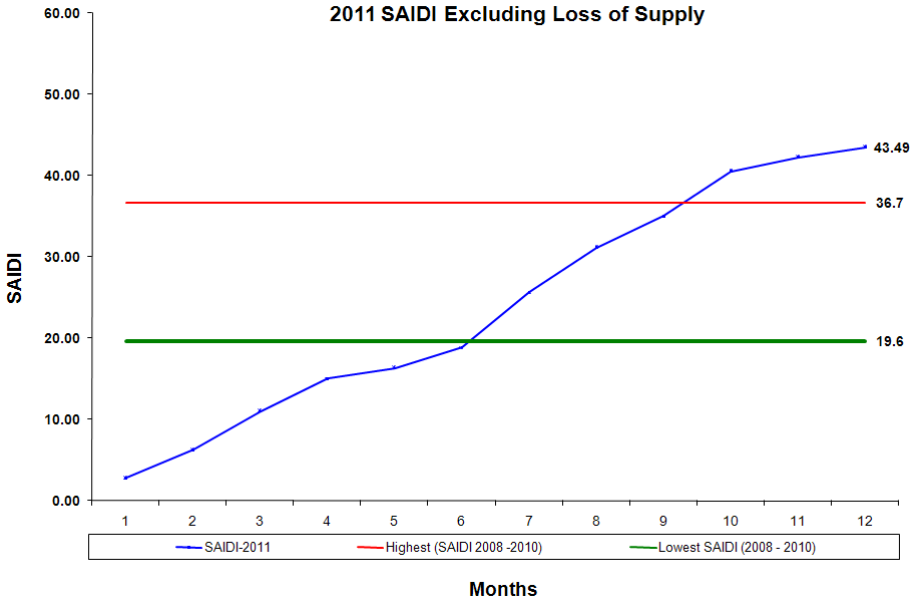


Figure 3: Enersource 2011 SAIFI Results

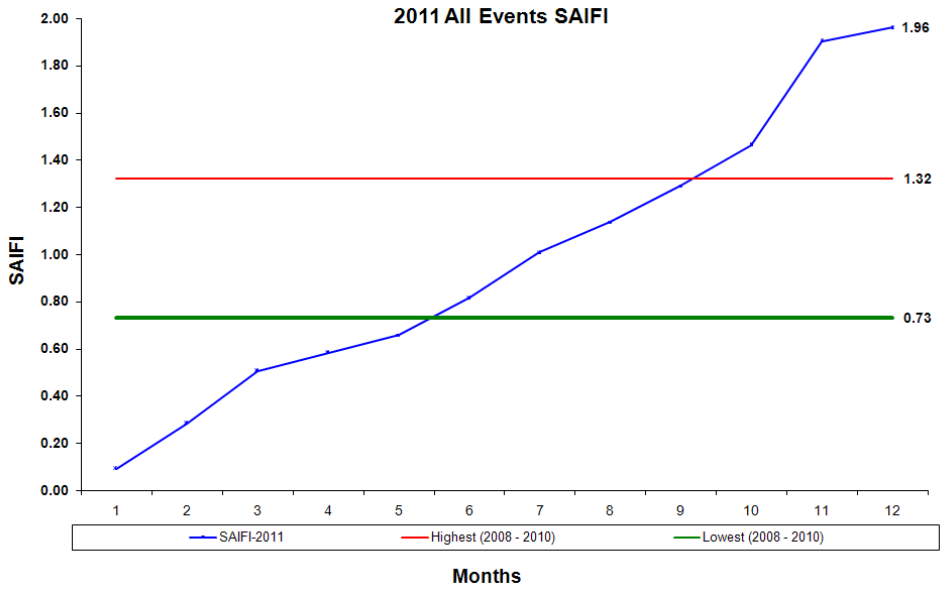


Figure 4: Enersource 2011 SAIFI Results – Excluding Loss of Supply

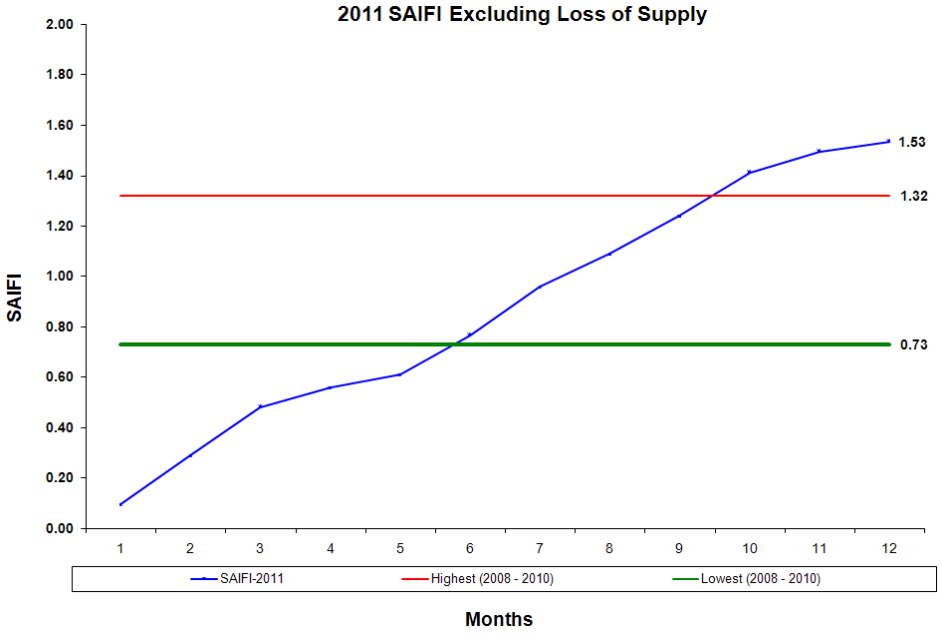


Figure 5: Enersource 2011 CAIDI Results

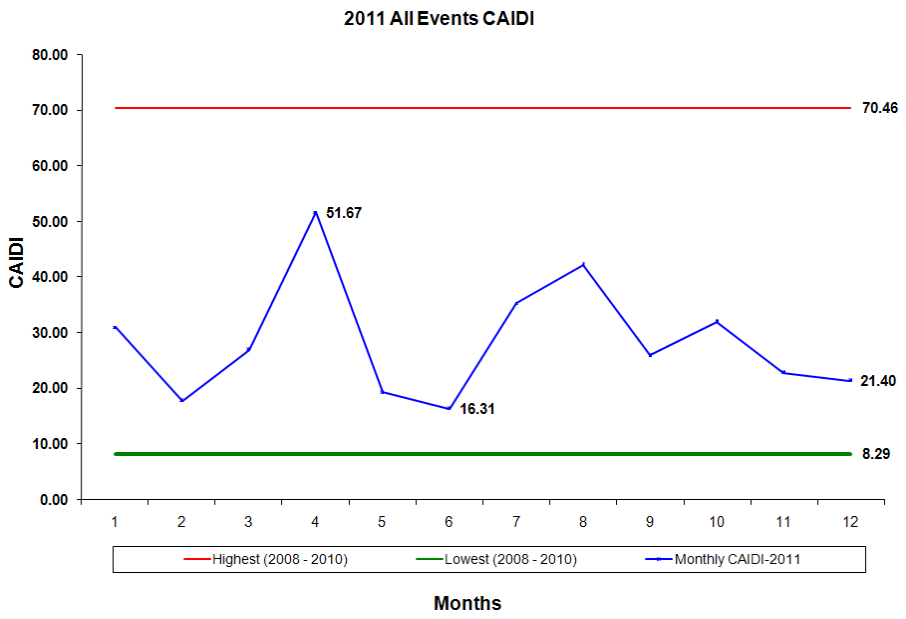
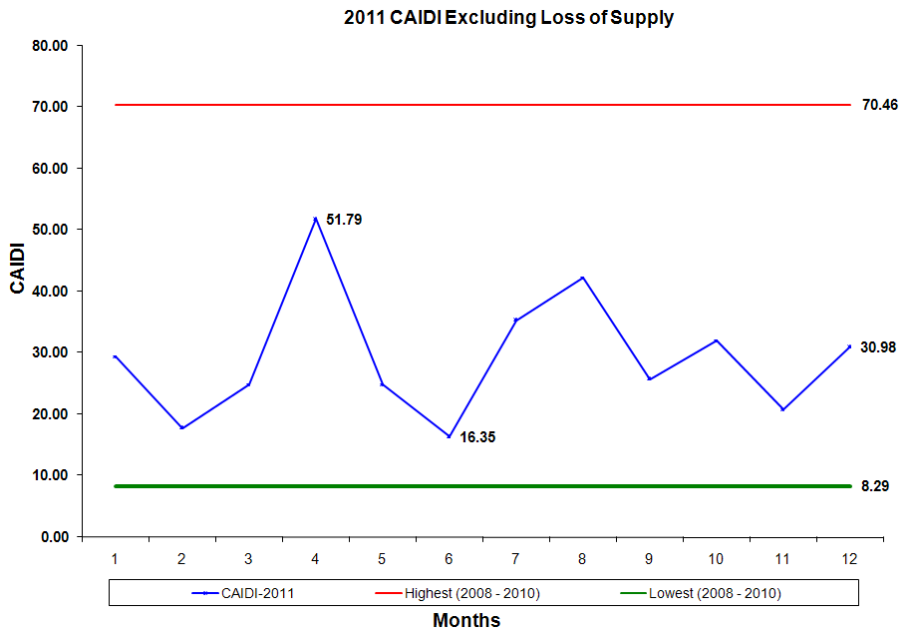


Figure 6: Enersource 2011 CAIDI Results – Excluding Loss of Supply



Major Incidents in 2011

There were three notable events which had a significant impact on the 2011 SAIDI and SAIFI results. These three events occurred on January 23, March 11, and November 11 and resulted in approximately 2.8 million customer minutes of interruptions. They are each described in some detail below.

Absent these three events, the SAIDI results for 2011 fell just outside the 3-year historical band, as shown in Figure 7.

Absent these three events, the SAIFI results for 2011 fall just within the 3-year historical band, as shown in Figure 8.

Incident on November 11, 2011

There was a major power interruption on Friday November 11, 2011. The interruption was caused by a loss of supply at Richview Transformer Station ("TS").

The event affected approximately 68,700 customers and resulted in approximately 1.6 million customer minutes of interruptions.

All customers were restored within 29 minutes.

Incident on January 23, 2011

There was a major power interruption on the night of Sunday January 23, 2011 due to equipment issues at two transformer stations.

The event affected approximately 17,000 customers and resulted in approximately 482,000 customer minutes of interruptions.

All of the customers were restored within two hours and 35 minutes.

Incident on March 11, 2011

There was a major interruption of electricity on March 11, 2011, extending into March 12, 2011. The cause of the outage was an equipment issue. More specifically, a pole fire caused a wood pole breakage. Approximately ten work crews were deployed to restore all of the affected circuits, including one 70-foot pole replacement.

The event affected approximately 27,000 customers and resulted in approximately 710,000 customer minutes of interruptions.

All circuits returned to normal configuration in slightly less than thirty hours.

Figure 7: Enersource 2011 SAIDI Results – Excluding Three Major Incidents

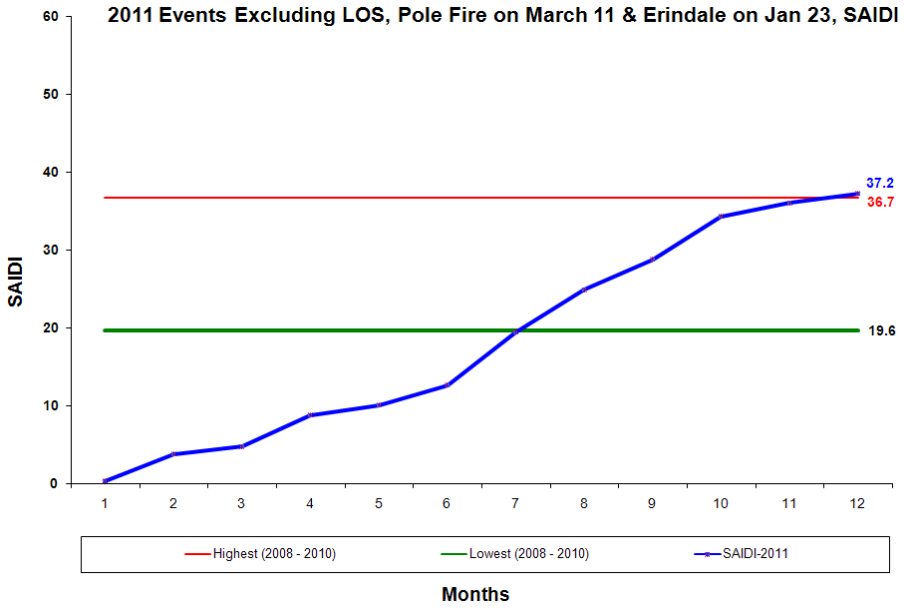
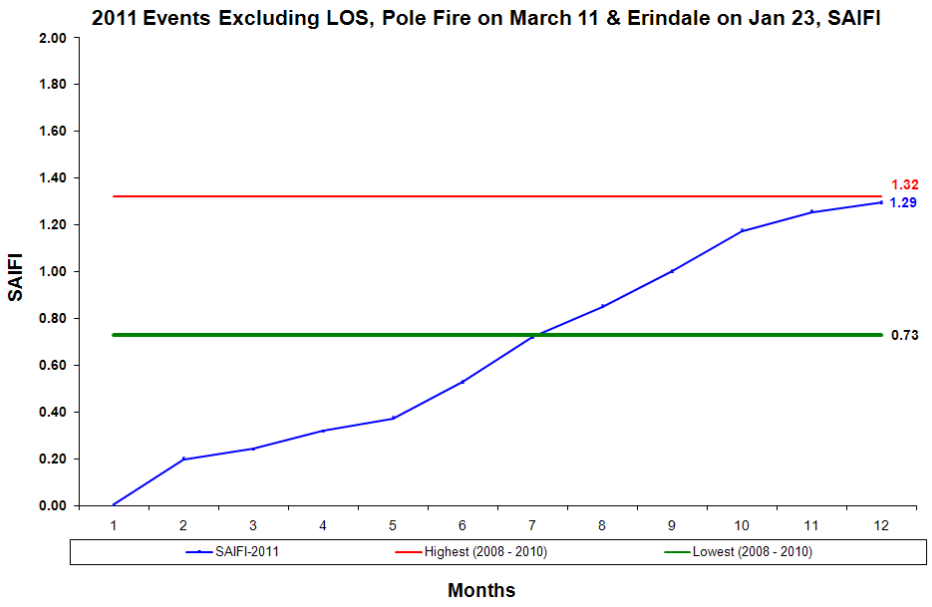


Figure 8: Enersource 2011 SAIFI Results – Excluding Three Major Incidents



Reliability Initiatives

Enersource has a number of programs and initiatives to address the reliability results in 2011. These are discussed more fully in the Asset Management Plan ("AMP") provided at Exhibit 2 Tab 2 Schedule 2. The following sections identify some of these actions.

Testing and Inspection Program

Enersource has several inspection programs for various distribution and sub-transmission equipment. The inspection programs include monthly substation inspections, pad-mounted switchgear inspections, overhead switch inspection, vault inspection, feeder patrol, and infrared scan of overhead distribution system. In addition, informal inspections are performed by all work crews in the field conducting normal day-to-day work.

The results of the inspection programs provide key information for the development of the asset management plan.

Switchgear Dry Ice Cleaning

Switchgear units are one of the most important components of the distribution system, with over 800 switchgear units in the Enersource system.

Enersource has a dry-ice maintenance cleaning program to clean padmounted switchgears, which are exposed to high levels of salt, debris and water contamination. This will mitigate faults and reduce premature equipment failure.

Last year the dry ice program cleaned 59 switchgear units. At the same time these switchgear units were inspected. Fifteen percent of the inspected switchgear units were found to have either water in the base of the switchgear; rust, paint peeling off the top or flash over mark.

Infrared Inspection

Enersource has an annual infrared inspection program which helps to detect defects in the electrical distribution system before they cause a major failure.

The intent of infrared thermographic inspection is to survey the electrical equipment for hot spots. This identifies potential problems and determines their seriousness.

Last year infrared inspection was performed on the entire overhead electrical distribution system. Twenty hot spots were identified and repaired by Enersource overhead maintenance crews.

Load Break Switch Maintenance Program

The distribution system has different types of switches to facilitate distribution of electrical load safely under normal and abnormal conditions. Enersource use load Interrupters for overhead primary distribution system switching. These switches are one of the most important components of our distribution system. Enersource has ninety-two motorized switches that are maintained regularly in a three year cycle.

Last year thirty motorized switches underwent the necessary inspection and maintenance.

Station Maintenance Program

The maintenance programs of municipal substations consist of the following:

- Monthly inspections;
- Annual power transformer oil insulating testing; and
- Preventive maintenance of the electrical equipment on a regular schedule.

It is the practice of maintaining the substations electrical equipment on a regular schedule. It is the objective to perform preventive maintenance approximately once every five years to each municipal power substation.

Maintenance Activities

Transformer Maintenance Activities

Transformer maintenance activities are based on the following documents and standards:

- Manufacturer's Instruction book;
- IEEE 62-1995 IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus Part 1: Oil Filled Power Transformers, Regulators, and Reactors; and
- Doble Transformer Maintenance and Test Guide.

Switchgear Maintenance Activities

The switchgear maintenance is based on the manufacturer's instruction manual, and will include, as a minimum, the following:

- Busbar, enclosure and insulators maintenance; and
- Circuit breaker maintenance.

Protection Relays Maintenance

Three types of relays are used to clear the faults that occur in Enersource's distribution grid:

- Electromechanical (GE IAC type) relays; the maintenance tasks shall include:
    - Visual Inspection;
    - Mechanical adjustment and inspection; and
    - Electrical tests and adjustments.
- Electronic Relays (MCGG type) relays – since there are no moving parts in the electronic relays, there is no physical wear due to usage; the maintenance consists of secondary injection tests; and
- Microprocessor based (UR type) relays – only injection tests shall be performed as maintenance tasks.

Batteries and Battery Charger

The batteries and battery charger maintenance consists of the following activities:

- Record the room temperature;
- Measure and record the battery voltage;
- Measure and record each battery voltage; and
- Record the charge current.

Pole Testing Pilot Program

Pole testing and inspection program is a safe and economical pole management program that extends the life cycle of the wood pole distribution system and allows for future planning through the collection of useful data.

The objective of the pole testing is to ensure the distribution system operates safely; to identify remaining life of the pole and collect useful data of the infrastructure.

Enersource is in the process of establishing a pole testing and inspection program. Three vendors were selected to do a pilot project. The purpose of this pilot project is to test approximately three hundred poles using two different pole testing methods known as Visual, Sound and Drill and Non-Destructive (using a Resistograph).

The results of the pilot project will be reviewed by Enersource personnel, and, based on the accuracy of the test results, one vendor will be selected to complete a full pole testing and inspection program.

Ten Worst Feeder Study

The IOM outage reports are used to identify the worst performing feeders by analyzing historical outage data. Some of the measures typically looked at are: number of outages, total customer outage minutes, number of customers affected, and number of auto reclosures. Feeders are ranked based on the outage types by weighting factors. The highest scores indicate feeders which are identified as needing additional review to determine action plans; this analysis assists in determining future overhead and underground maintenance programs.

Subtransmission and Distribution Program Projects in 2012 and 2013

The following list identifies the major subtransmission and distribution projects that are scheduled for construction in 2012. Each is described more fully in the AMP.

1) 44/13.8kV Dundas Street – Glengarry Rd to Mississauga Road
2) McNiece MS Feeders – CN Railway Relocations
3) Revus MS Feeders – CN Railway Relocations
4) The Queensway – Hurontario Street to Camilla Road
5) Hurontario Street and QEW Overpass
6) Clarkson Rd – Lakeshore Road to Hydro One ROW
7) Dundas Street – Jaguar Valley to Cawthra Road

The following list shows some of the subtransmission and distribution projects that are proposed for construction in 2013.

1) 44kV Churchill Meadows TS Feeder Egress – along Hydro One Right of Way

2) Royal Windsor – Winston Churchill to Avonhead Road

3) Lakeshore Road – Hurontario Street to Cawthra Road

4) Lakeshore Road – Hurontario Street to Kane Road

5) The Queensway – Cawthra Street to Dixie Road

6) Burnhamthorpe Road West – Winston Churchill Boulevard to Ridgeway Drive

Subdivision Rebuilds Program Projects in 2012

The following list identifies the major subdivision rebuild projects that are scheduled for construction in 2012. Each is described more fully in the AMP.

1) Loyalist Drive Main Feeder Rebuild

2) Aquitaine Avenue and Montevideo Road Phase 1 Rebuild

3) Campobello Road and Falconer Drive Main Feeder Rebuild

4) Robert Speck Parkway Main Feeder Rebuild

5) Paisley Boulevard and Whaley Drive Rebuild

6) Aquitaine Avenue and Montevideo Road Phase 2 Rebuild

7) Ponytrail Drive and Rathburn Road Rebuild

8) Cullen Avenue Rebuild

9) 90 Farmcottage Court Rebuild

10) Ellengale Drive Rebuild

Sherobee Road Rebuild

In addition to the above projects the Sherobee Road rebuild project is also required. The project involves replacement of four non-standard power transformers, along with the associated accessories and cables.

Overhead Rebuilds Program Projects in 2012

For further detail on the following list of 2012 overhead rebuild projects, please refer to the AMP.

1) Old Meadowvale Village Overhead Conversion
2) Lorne Park Estate Rebuild
3) Martley Drive Rebuild
4) Orchard Road Rebuild
5) Birchwood Drive Rebuild
6) Bremen Lane Rebuild

Major Outage Case Studies and Other Reliability Programs

Following all major outages (defined as outages greater than 100,000 customer minutes), Enersource conducts a thorough review of the event. This review commences by arranging a meeting with the reliability engineers, control room operators, the on-call construction supervisor and other engineering staff to review the outage and its causes, and to review the remedial actions during the event and proposed for the future.

Service Quality and Reliability Performance 2009 - 2011

Table 1- Enersource Customer Service Quality Indicators, 2009 to 2011

Service Quality Indicator	OEB Approved Standard	% of Annual Average Performance		
		2009	2010	2011
Connection of New Services Low Voltage	At least 90% on a yearly basis	97.9	99.7	99.2
Connection of New Services – High Voltage	At least 90% on a yearly basis	100.0	100.0	100.0
Appointments Scheduling	At least 90% on a yearly basis	100.0	97.3	97.0
Appointments Met	At least 90% on a yearly basis	100.0	100.0	99.0
Rescheduling a Missed Appointment	100% on a yearly basis	0.0	0.0	79.0
Telephone Accessibility	At least 65% on a yearly basis	81.4	82.0	81.0
Telephone Call Abandon Rate	10% or less on a yearly basis	2.9	2.5	2.4
Written Responses to Enquiries	At least 80% on a yearly basis	99.5	98.4	99.9
Emergency Response - Urban	At least 80% on a yearly basis	96.2	97.7	97.74
Emergency Response – Rural	At least 80% on a yearly basis	N/A	N/A	N/A
Reconnection Standards (commenced reporting for 2011)				98.93

Table 2 – Enersource Service Reliability Indices, 2009 to 2011 – Includes outages caused by loss of supply

OEB Approved Standard: Within the range of 3 years historical performance – Total number of customers equals the number of customer accounts served by the distributor in the reporting month.	**2009**	**2010**	**2011**
SAIDI (System Average Interruption Duration Index)	0.61	0.58	0.89
SAIFI (System Average Interruption Frequency Index)	1.16	1.32	1.97
CAIDI (Customer Average Interruption Duration Index)	0.53	0.44	0.45

Table 3 – Enersource Loss of Supply Adjusted Service Reliability Indices, 2009 to 2011 – Excludes outages caused by loss of supply

OEB Approved Standard: Within the range of 3 years historical performance – Total number of customers equals the number of customer accounts served by the distributor in the reporting month.	**2009**	**2010**	**2011**
SAIDI (System Average Interruption Duration Index)	0.57	0.55	0.73
SAIFI (System Average Interruption Frequency Index)	0.92	1.10	1.54
CAIDI (Customer Average Interruption Duration Index)	0.62	0.50	0.47

Load Forecast Methodology Overview

Introduction

Enersource's load forecasting process utilizes multivariate regression load forecast models based on weather, calendar, and econometric variables to estimate the relationship between energy consumption or peak demand to analytical factors and drivers. The analytical factors include sixteen years of actual historical energy consumption data, actual weather data, and calendar data. Model drivers include econometric data such as gross domestic product ("GDP"), consumer price index ("CPI"), population, and employment which are obtained from Conference Board of Canada as well as the Building and Planning Department with the City of Mississauga ("City" or "Mississauga"). Enersource has been utilizing this load forecast process since 2004 and has found it to be robust and effective. Since 2004, the forecasts have produced energy consumption forecasts within 0.3% of actual energy purchases and 1.7% to weather-corrected energy purchases, when incremental conservation and demand side management savings are considered.

Although weather is a significant contributor to both energy consumption and peak demand in Mississauga, Enersource's load forecasting process does not predict weather. Instead, Enersource utilizes weather scenarios to derive system load energy consumption forecasts and system load peak demand forecasts. Two scenarios are derived using 31 years of actual weather data to establish normal and extreme weather scenarios.

Enersource utilizes the same actual data and inputs, and similar modeling processes for establishing short term energy consumption and peak demand forecasts as it does for long term system load forecasts that underpin the system capacity and asset management plans. Hence, weather scenarios derived for

short term energy consumption are also utilized for long term system planning requirements.

Historical Data (1996-2011)

Sixteen years of Enersource's actual energy purchases from the Ontario electricity wholesale market from 1996 to 2011 are used to establish relationships between analytic and econometric drivers to energy and peak demand. The annual energy purchases from the Independent Electricity System Operator ("IESO") have increased over the sixteen-year period at an average annual rate of 1.45%. When corrected for normal weather, the average annual consumption growth rate for that period was found to be 1.36%.

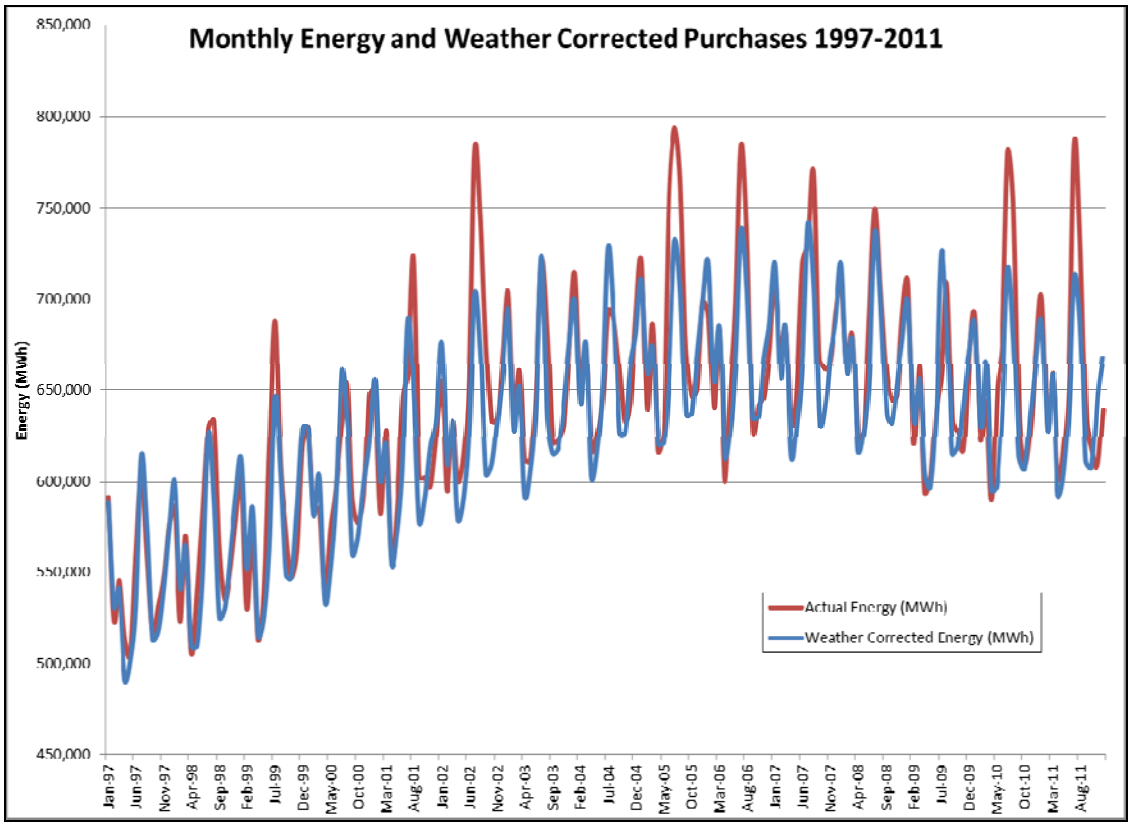
Table 1 below provides the annual energy purchases from 1997 to 2011, actual and weather-corrected, and identifies the annual growth rates. Figure 1 follows and provides the same annual energy purchase information in illustrative format.

Table 1: Annual Energy and Weather-Corrected Energy Purchases with Annual Growth Rates (1997-2011)[1]

Year	Actual Energy Purchases (MWh)	Annual Growth (%)	Weather-Corrected Energy Purchases (MWh)	Weather-Corrected Growth (%)
1997	6,572,075	2.85	6,519,322	2.85
1998	6,794,034	3.38	6,697,846	2.74
1999	6,970,573	2.60	6,914,120	3.23
2000	7,193,867	3.20	7,137,503	3.23
2001	7,455,765	3.64	7,367,444	3.22
2002	7,885,981	5.77	7,594,021	3.08
2003	7,829,380	-0.72	7,720,062	1.66
2004	7,940,668	1.42	7,906,647	2.42
2005	8,281,072	4.29	8,024,379	1.49
2006	8,038,676	-2.93	8,035,586	0.14
2007	8,249,692	2.63	8,052,075	0.21
2008	8,096,552	-1.86	7,995,947	-0.70
2009	7,742,344	-4.37	7,788,628	-2.59
2010	7,949,146	2.67	7,739,098	-0.64
2011	7,880,490	-0.86	7,744,998	0.08

[1] In order to show relative growth (and avoid the first point on the figure starting from zero), the table and figures start with 1997 data relative to 1996 data.

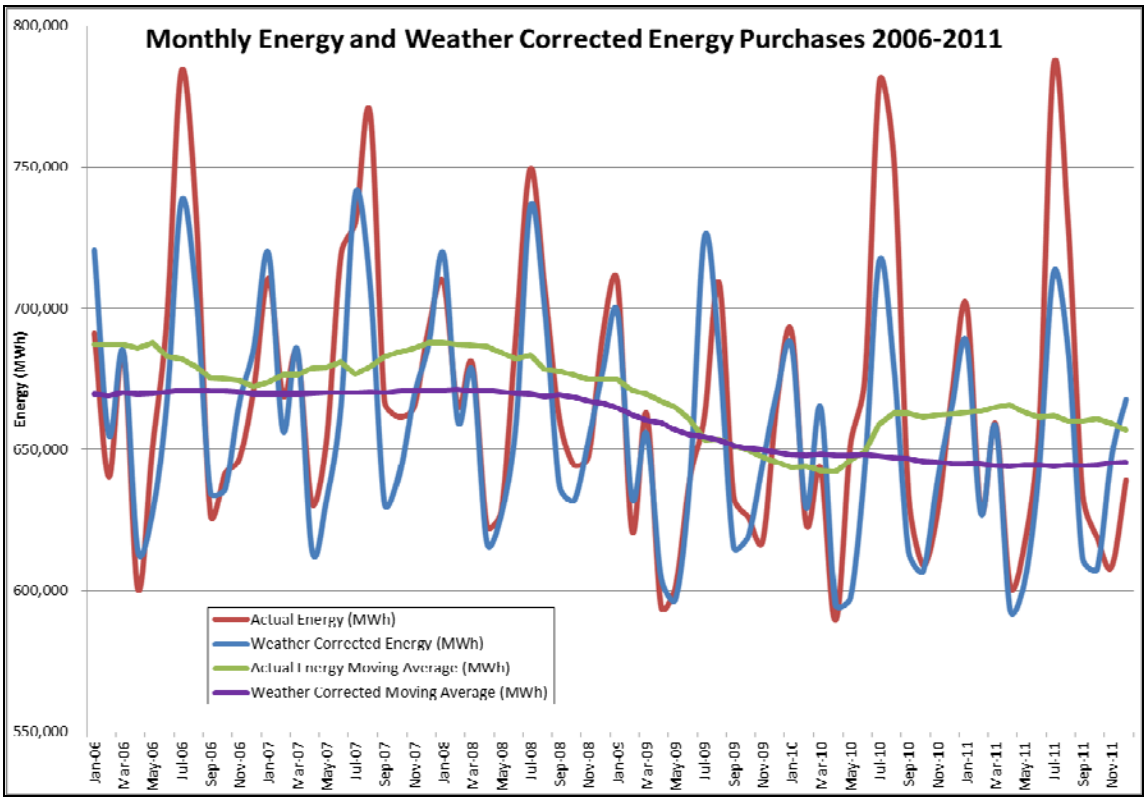
Figure 1: Monthly Energy and Weather-Corrected Energy Purchases (1997-2011)



Examining the most recent six-year span from 2006 to 2011, energy consumption in Mississauga was found to have exhibited an annual average growth of -0.79%, i.e., an annual average decline of 0.79%. When corrected for normal weather, the annual weather-corrected consumption growth averaged -0.58%, i.e., a 0.58% average decline, per year. Recent energy consumption decreases in Mississauga are attributed to unfavourable economic conditions and energy savings from conservation programs delivered in Mississauga by Enersource.

Figure 2 illustrates the actual and weather-corrected monthly energy purchases with moving average trend lines.

Figure 2: Monthly Energy and Weather-Corrected Energy Purchases (2006-2011)

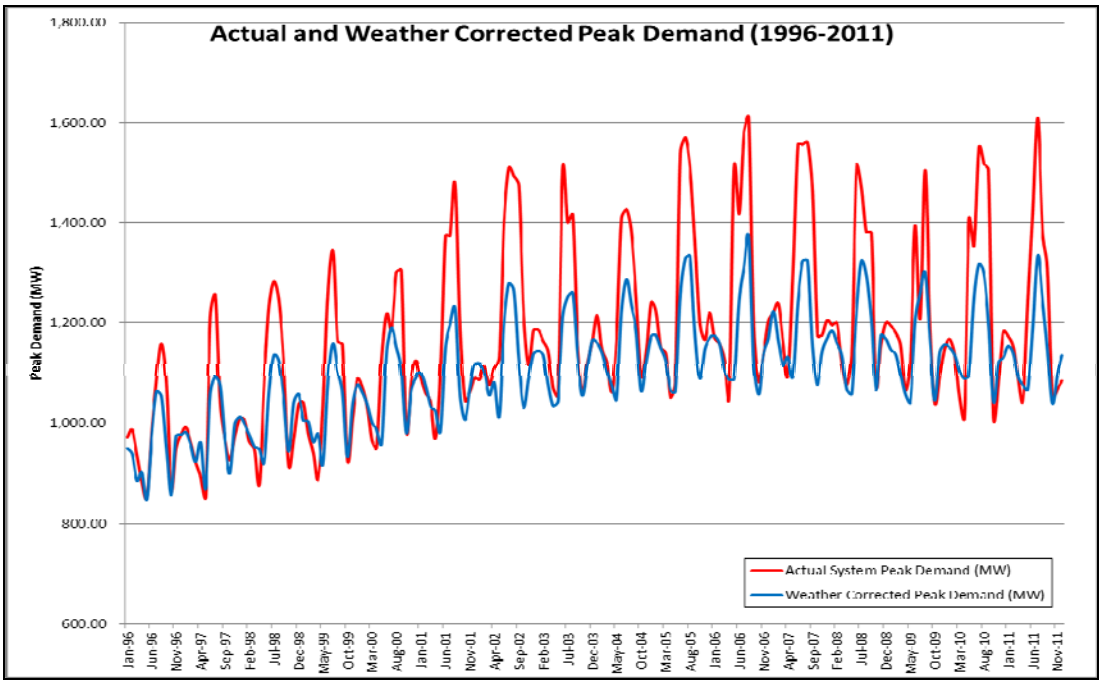


In addition, due to decreasing availability of land for development, over the last six years Mississauga has transitioned from greenfield development to intensification and redevelopment. The City's Building and Planning Department continues to project growth, led by condominium and office space developments; however, the projected rate of growth will be significantly lower compared to historical annual averages.

From 1996 to 2011, Enersource's average annual peak demand growth rate over that sixteen year period was 2.34%. This is illustrated in Figure 3. Enersource experienced an all-time system peak of 1,610 MW in August, 2006. Examination of the annual peak demand growth rate for the most recent six years, from 2006 to 2011, shows that the average annual peak demand growth rate was 0.45%.

This reduction in peak demand growth rate can be attributed to the significant reduction in peak demand due to economic conditions in 2007, 2008, and 2009. Figure 3 demonstrates that although annual energy consumption has decreased over the same period, short durations of extreme weather have driven system peak demand to near-record levels for short durations, and hence, require Enersource to build capacity to withstand such peak demands on the system.

Figure 3: Actual and Weather-Corrected Peak Demand (1996-2011)



Load Forecasting Methodology

Enersource's load forecast was developed using statistical analysis software MetrixND® from Itron Inc. The following actual historical data was used as inputs into the model:

- Hourly system load data from January 1996 to December 2011;

- Hourly weather data from 1980 to 2011 (temperature, dew point) obtained from Environment Canada for Lester B. Pearson International Airport;
- City of Mississauga demographic variables, including population and employment from the City of Mississauga's Building and Planning Department; and
- Econometric variables including GDP and CPI from the Conference Board of Canada, dated November, 2011.

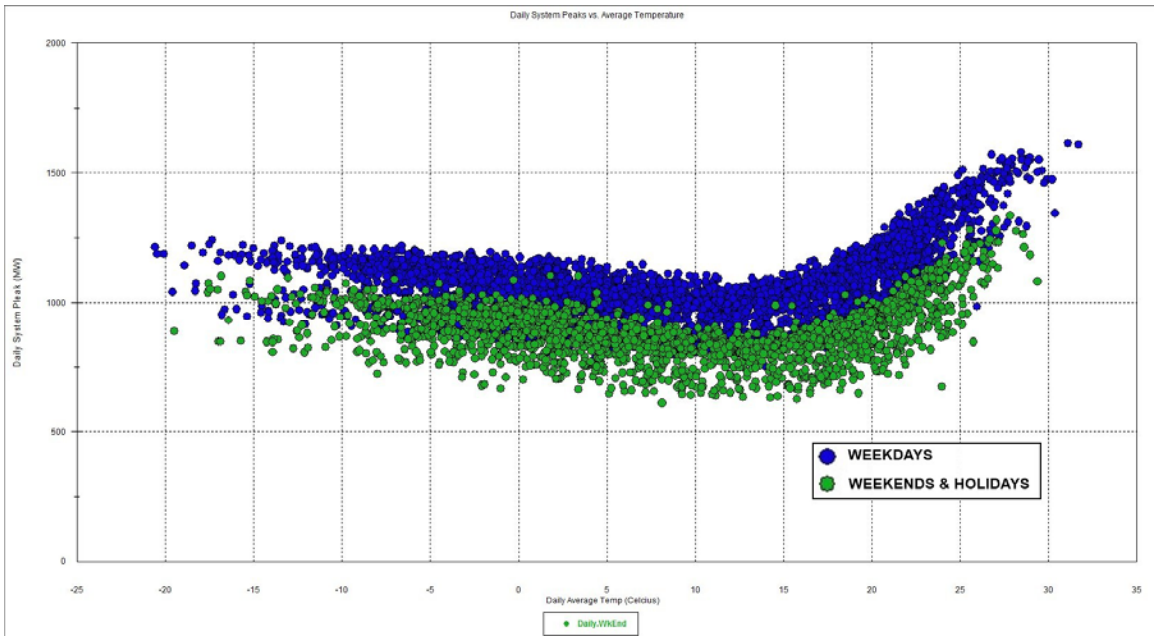
Actual historical energy consumption and peak demands are modelled to weather and calendar variables, and to econometric, binary, and trending variables in order to capture relationships. Binary variables are used to incorporate seasonal effects into the model. A trending variable is utilized in the models to capture impacts of time-related initiatives such as energy efficiency, including conservation and demand management savings implemented. It is important to note that trending variables only capture implemented initiatives with persistence and do not incorporate incremental projections of energy efficiency savings. Hence, future conservation and demand management energy savings are incorporated by adjustments to energy and peak demand forecasts. (The CDM adjustments are discussed in detail at Exhibit 3 Tab 1 Schedule 2).

Weather

Hot and cold weather are prominent factors in driving energy consumption in Mississauga. Figure 4 illustrates the impact of weather on the system load including the impact of workday (blue dots) from weekend and holidays (green dots). The scatter plot was utilized to derive appropriate heating, cooling, and extreme cooling degree splines at 10° C, 18° C, and 22° C, respectively. The system model is developed using actual system load data with actual weather

data obtained for the Lester B. Pearson International Airport weather station from the National Climate Data Archives at Environment Canada.[2]

Figure 4: Plot of Daily System Peaks to Daily Average Temperature (1996-2011)



Enersource utilizes both dry bulb temperature ("temperature") and dew point temperature ("dew point") data. Dew point is a measure of the humidity or moisture content in the air. In addition to temperature and dew point, Enersource's load forecasting system considers a temperature build-up variable to demonstrate the relationship of several consecutive days of hot or cold temperature to denote a heat wave or cold spell.

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[2] http://climate.weatheroffice.gc.ca.

Calendar Drivers

Calendar variables include days of the week and holidays, both of which impact energy consumption. As illustrated in Figure 4, energy consumption is greater during the workweek than weekends and holidays at the same temperature. The number of hours of daylight is another calendar factor considered in modelling system peak demand and varies from shorter daylight in the winter to longer daylight in the summer seasons.

Econometric Data

Several econometric factors are utilized to drive the forecast model of energy consumption and peak demand in Mississauga. Actual and forecasted economic indicators of GDP and CPI are obtained from the Conference Board of Canada, and are listed in Table 2 below.

Table 2: Econometric Drivers for Toronto Region
(Source: Conference Board of Canada, November, 2011)

Year	GDP (2002$Millions)	GDP Growth	CPI (2002=1.0)	CPI Growth
1996	143,097		0.879	
1997	150,775	5.37%	0.894917	1.81%
1998	159,128	5.54%	0.90425	1.04%
1999	172,717	8.54%	0.922083	1.97%
2000	184,848	7.02%	0.950083	3.04%
2001	188,562	2.01%	0.979583	3.10%
2002	193,804	2.78%	1	2.08%
2003	197,191	1.75%	1.030417	3.04%
2004	202,724	2.81%	1.046917	1.60%
2005	208,882	3.04%	1.0665	1.87%
2006	214,508	2.69%	1.08375	1.62%
2007	219,651	2.40%	1.1045	1.91%
2008	219,130	-0.24%	1.13125	2.42%
2009	213,289	-2.67%	1.136417	0.46%
2010	221,624	3.91%	1.16475	2.49%
2011	226,614	2.25%	1.200439	3.06%
2012	232,543	2.62%	1.225477	2.09%
2013	241,919	4.03%	1.253597	2.29%

Actual and forecasted population and employment data are obtained from the City's Building and Planning Department, and are listed in Table 3.

Table 3: Demographic Data for Mississauga (Source: City of Mississauga Building and Planning Department)

Year	Population (000s)	Population Change	Employment Lands (000)	Employment Lands Change	Major Office Empl (000s)	Major Office Change
1996	566		166		51	
1997	583	3.01%	179	7.63%	54	7.06%
1998	600	2.82%	192	7.20%	58	6.18%
1999	615	2.63%	203	6.10%	61	6.48%
2000	630	2.44%	213	4.75%	66	7.03%
2001	645	2.26%	220	3.37%	70	7.35%
2002	658	2.07%	225	2.10%	75	7.24%
2003	671	1.90%	227	1.01%	81	6.71%
2004	682	1.72%	227	0.15%	85	5.87%
2005	693	1.55%	226	-0.44%	89	4.86%
2006	702	1.39%	225	-0.75%	93	3.82%
2007	711	1.24%	223	-0.77%	95	2.85%
2008	719	1.09%	222	-0.51%	97	2.07%
2009	726	0.96%	222	-0.03%	99	1.55%
2010	732	0.83%	223	0.58%	100	1.34%
2011	737	0.72%	226	1.20%	103	2.24%
2012	741	0.61%	229	1.53%	105	2.39%
2013	745	0.52%	234	2.09%	107	1.90%

The results of Enersource's multivariate regression model, and specifically the affecting factors of conservation and demand management and weather on the short term load forecast, are addressed at Exhibit 3 Tab 1 Schedule 2.

The long term peak demand forecast is addressed at Exhibit 2 Tab 2 Schedule 2 Appendix 1, i.e., the Asset Management Plan.

Multivariate Regression Model Results

This exhibit provides the results of the load model forecast discussed in Exhibit 3 Tab 1 Schedule 1. Included is the forecast of short term system energy consumption, short term system peak demand, and customer numbers. This exhibit also addresses the impacts of conservation and demand side management ("CDM"), weather normalization methodology, and an assessment of the model performance. Please note that distribution revenues and use-per-customer is discussed in Exhibit 3 Tab 2 Schedule 1.

Short Term System Energy Consumption Forecast

The energy consumption forecast model introduced and discussed at Exhibit 3 Tab 1 Schedule 1 performs very well with an adjusted R^2 of 0.987, indicating that 98.7% of the variations in energy consumption from 1996 to 2011 are explained by the variables in the model. Furthermore, the model statistics indicate a Mean Absolute Percentage Error (“MAPE”) of 0.86% with a monthly mean absolute deviation (“MAD”) of 5,413 MWh. Additional model statistics including coefficient values, standard error, T-Stat and P-Values are included in Appendix A. As illustrated in Table 1 below, system energy consumption under normal weather is expected to increase by 0.06% in 2012 relative to weather-corrected 2011 consumption. Energy consumption is projected to increase by 0.88% in 2013.

Table 1: Actual/Forecast and Weather-Corrected Energy Consumption, 2006 to 2013

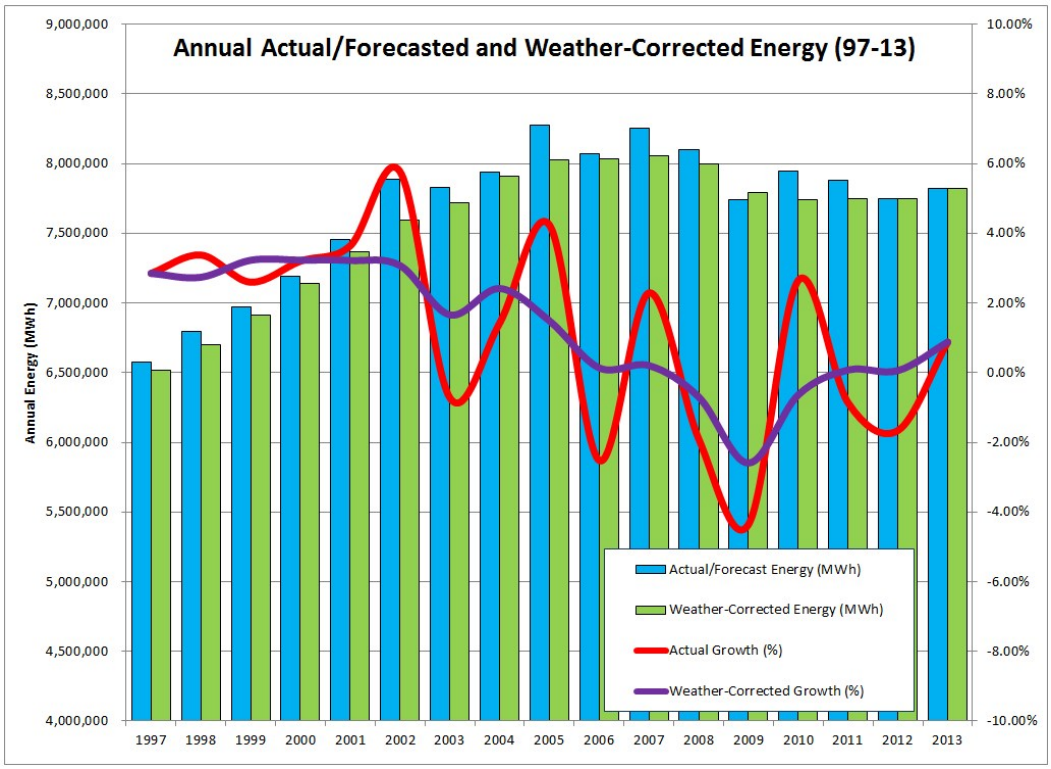
Year	Actual/Forecast Energy Consumption (MWh)	Actual Growth (%)	Weather-Corrected Energy Consumption (MWh)	Weather-Corrected Growth (%)
2006	8,038,676	-2.93	8,035,586	0.14
2007	8,249,692	2.63	8,052,075	0.21
2008	8,096,552	-1.86	7,995,947	-0.70
2009	7,742,344	-4.37	7,788,628	-2.59
2010	7,949,146	2.67	7,739,098	-0.64
2011	7,880,490	-0.86	7,744,998	0.08
2012*	7,749,733	-1.66	7,749,733	0.06
2013*	7,817,741	0.88	7,817,741	0.88

* Incremental CDM activities not included

Note that the forecast in Table 1 does not include the anticipated impacts of incremental CDM activities, which is discussed later in this exhibit.

Figure 1 below illustrates the annual energy consumption, weather-corrected energy consumption, annual growth rates and weather-corrected annual growth rates on an actual basis from 1997 to 2011, and as forecast from 2012 to 2013.

Figure 1: Actual/Forecast and Weather-Corrected Energy Consumption, 1997 to 2013



Short Term System Peak Demand Forecast

The system peak demand forecast was derived using an extreme weather scenario. (The extreme weather scenario is described more fully below). The model fit was found to be statistically significant with an adjusted R^2 of 0.95 indicating that the model captures 95% of the peak demand variation from 1996 to 2011. Furthermore, the model statistics indicate a MAPE of 2.46% with a MAD of 24.16 MW.

Figure 2 and Table 2 below provide the actual and forecast system peak demand from 1996 to 2013, assuming the extreme weather scenario. The forecast indicates a 3.28% peak demand growth in 2012 relative to the actual 2011 system peak, and 0.45% peak demand growth in 2013, as shown in Table 2.

Figure 2: Actual and Forecast System Peak Demand (Extreme Weather), 1996 to 2013

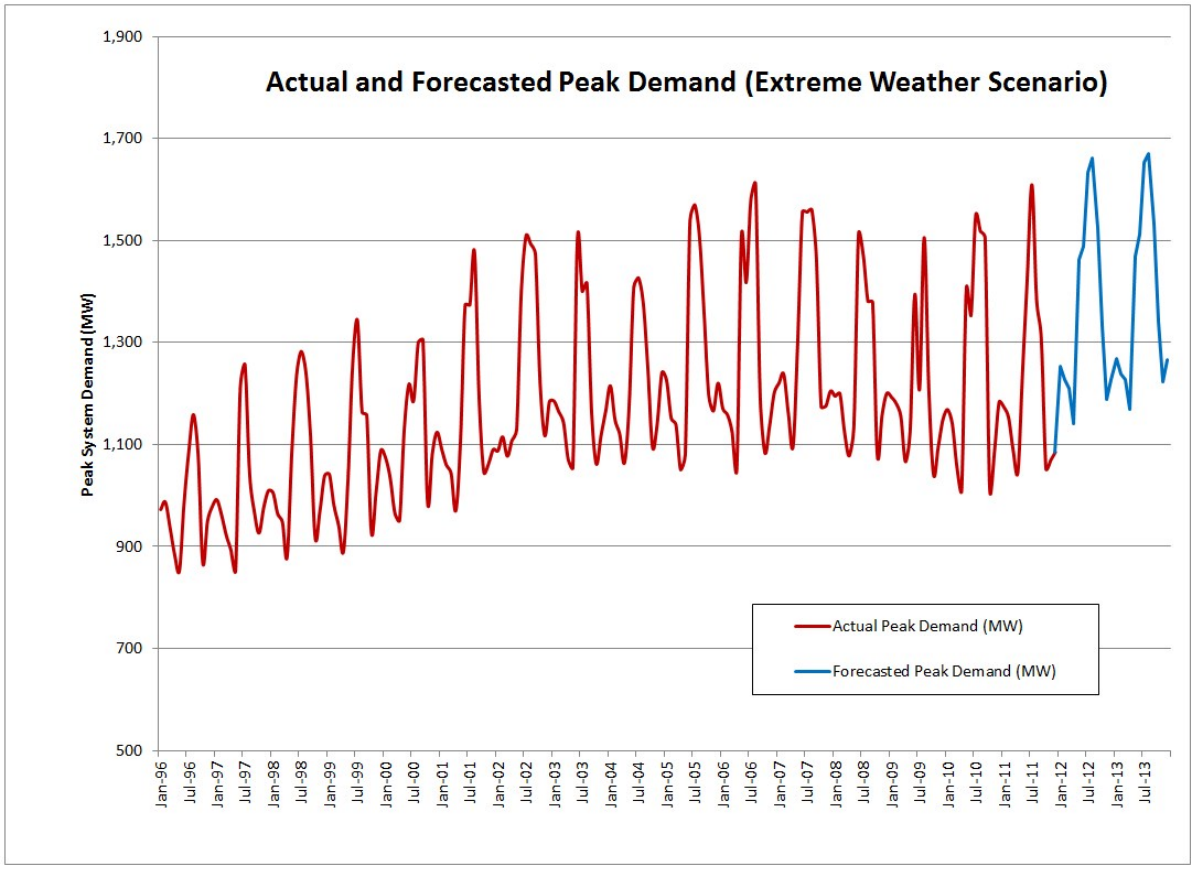


Table 2: Actual and Forecast System Peak Demand (Extreme Weather), 1997 to 2013

Year	System Peak Demand (MW)	Annual Growth (%)
1997	1,256	8.43
1998	1,283	2.11
1999	1,344	4.76
2000	1,305	-2.87
2001	1,477	13.16
2002	1,509	2.20
2003	1,505	-0.26
2004	1,427	-5.22
2005	1,570	10.05
2006	1,610	2.54
2007	1,560	-3.10
2008	1,513	-3.05
2009	1,506	-0.47
2010	1,550	2.93
2011	1,609	3.86
2012*	1,662	3.28
2013*	1,670	0.45

* Table 2 excludes incremental CDM savings in 2012 to 2013

Adjustments for Conservation and Demand Side Management

Enersource delivered CDM programs funded through third tranche revenue and is currently delivering CDM programs that are funded through the Ontario Power Authority ("OPA"). On November 12, 2010, the Board issued a Decision and Order[1] which specified the CDM targets which Enersource must meet as a condition of its licence. These targets are 92.98 MW for the 2014 Net Annual Peak Demand Savings and 417.22 GWh for the 2011-2014 Net Cumulative Energy Savings. Enersource continues to deliver OPA programs to meet these new targets.

[1] Board Dockets EB-2010-0215 and EB-2010-0216 Decision and Order dated November 12, 2010, Appendix A, line 18.

The impact of historical CDM programs on the load in future years is incorporated in the load forecast presented in Table 1 above as a CDM trending variable is utilized in the load forecast model. The load forecast model however does not incorporate projections of incremental energy savings from the aggressive CDM targets that Enersource will need to deliver in 2012 to 2013. Hence, Enersource has adjusted the forecast shown in Table 1 with the cumulative increases in CDM over and above those included in the load forecast model over the 2012 to 2013 period. The incremental CDM energy consumption savings are identified in Table 3 below.

Table 3: CDM Adjustments by Customer Class, 2012 to 2013 (kWh)

Rate Class	2012 CDM Adjustment	2013 CDM Adjustment
Residential	(22,709,000)	(35,842,920)
Small Commercial	-	-
Unmetered Scattered Load	-	-
GS < 50	(32,620,613)	(39,519,293)
GS 50-499	(4,349,853)	(6,718,613)
GS 500-4999	(4,648,053)	(7,166,687)
Large User	(14,714,815)	(8,983,655)
Street Lighting	(5,228,799)	(20,915,195)
Total	**(84,271,133)**	**(119,146,362)**

Table 3 highlights the adjustment made to the sales forecasts by customer class to reflect the load reductions in 2012 and 2013 as a result of the incremental CDM activities. A detailed monthly breakdown of the CDM adjustment shown on Table 3 is provided as Attachment 1 to this exhibit.

The net result of the CDM adjustments yields an overall consumption forecast as shown in Table 4 below. The forecast data on Table 4 is also shown at Attachment 2, which provides the actual and forecast sales by rate class, net of CDM impacts, from 2008 to 2013.

Table 4: Energy Consumption Forecast Including CDM Impacts, 2012 to 2013 (kWh)

	Energy Consumption Forecast (per Table 1)	CDM Adjustment (per Table 3)	Energy Consumption Forecast
2012			
Residential	1,498,238,071	(22,709,000)	1,475,529,071
Small Commercial	908,655	-	908,655
Unmetered Scattered Load	10,663,801	-	10,663,801
GS < 50	667,052,720	(32,620,613)	634,432,107
GS 50-499	2,204,055,980	(4,349,853)	2,199,706,127
GS 500-4999	2,316,967,744	(4,648,053)	2,312,319,691
Large User	1,011,627,005	(14,714,815)	996,912,190
Street Lighting	40,218,989	(5,228,799)	34,990,190
Total	**7,749,732,964**	**(84,271,133)**	**7,665,461,831**
2013			
Residential	1,510,959,264	(35,842,920)	1,475,116,344
Small Commercial	916,349	-	916,349
Unmetered Scattered Load	10,756,816	-	10,756,816
GS < 50	672,829,817	(39,519,293)	633,310,524
GS 50-499	2,223,403,707	(6,718,613)	2,216,685,094
GS 500-4999	2,337,688,588	(7,166,687)	2,330,521,901
Large User	1,020,566,402	(8,983,655)	1,011,582,747
Street Lighting	40,619,625	(20,915,195)	19,704,431
Total	**7,817,740,567**	**(119,146,362)**	**7,698,594,205**

Weather Normalization Methodology

Since forecasting weather with confidence is not reasonable, Enersource's load forecasting process utilizes two weather scenarios which are generated based on actual historical weather data for Mississauga. The two scenarios that are used are normal weather used for energy consumption forecasting, and extreme weather for peak system demand forecasting. Normal weather scenario is used for energy consumption since it provides the most typical weather conditions relative to historical experience. The extreme weather scenario is utilized for peak system demand forecasting to project the peak load demand which occurs

when the system is under duress. It would not be appropriate to use the extreme weather scenario for energy consumption forecasting as the likelihood of observing sustained extreme weather is highly unlikely. However, in assessing the system's capability to meet a one-hour summer peak, a monthly extreme peak demand forecast would be more appropriate.

Enersource utilizes 31 years of historical weather data to generate the normal and extreme weather scenarios. This is consistent with the weather normalization process used by the Independent Electricity System Operator ("IESO") to derive its *18-Month Outlook – An Assessment of the Reliability and Operability of the Ontario Electricity System*.[2]

The practice of weather normalization using 30 years of historical data is also consistent with weather normalization practices at Environment Canada[3] and the World Meteorological Organization.

The World Meteorological Organization Climatological Practices (WMO-No.100) indicates that climatological standards for normal weather are computed based on data from consecutive periods of 30 years.[4]

The use of 31 years by Enersource, rather than 30, is required as the normal and extreme weather scenarios are based on median data for actual days and not on averages. Selecting a median not based on averages requires an odd number. This is explained more fully below.

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[2] Source: "Methodology to Perform Long Term Assessments", Nov 2011, IESO_REP_0266v17.0 Outlook Methodology, Page 5.
[3] http://www.climate.weatheroffice.gc.ca/climate_normals/index_e.html, http://www.climate.weatheroffice.gc.ca/prods_servs/normals_documentation_e.html
[4] www.wmo.int/pages/prog/wcp/ccl/guide/guide_climat_practices.html

Enersource also observes that the Board has accepted a 31-year weather scenario in its adoption of the *Ontario Wholesale Electricity Market Price Forecast*[5] completed by Navigant Consulting, Ltd. ("Navigant") to underpin the Board's *Regulated Price Plan Price Report* every six months. Enersource recognizes that Navigant's price forecast is based on the IESO's 18 Month Outlook, which is based on weather normalization using 31 years of actual weather similar to the methodology used by Enersource. The use of 30 years of historical data is also supported by Itron Energy Forecasting Group ("Itron")[6] who are considered industry experts in electricity load forecasting.

Enersource submits that the determination of weather normalization using 30 years of data is a common, accepted protocol, as is evidenced by the practices of Environment Canada, the World Meteorological Organization, Navigant, the IESO, Itron and the Board. Thus, Enersource continues to base its load forecast on the same time period.

In recent years, some Board proceedings have introduced the use of a shorter period, ten years, for weather normalization purposes. For comparison purposes, Enersource has calculated its energy consumption forcast using this method. The 2012 and 2013 system energy consumption forecasts using both 11-year and 31-year weather are provided in Table 5 below. Table 5 illustrates that the impact of using a shorter period of weather normalization produces a slight (0.59%) increase in the forecasted system energy consumption.

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[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2004-0205/RPP_WholesaleElectricityPriceForecastRprt_20111017.pdf

[6] Dr. J. Stuart McMenamin, Itron Energy Forecasting White Paper, "Defining Normal Weather for Energy and Peak Normalization", 2008 Itron Inc.

Table 5: Comparison of 31-Year to 11-Year Normal Weather on Energy Consumption Forecast

	Energy Forecast (MWh)	
	2012	**2013**
31 Years	7,749,733	7,817,741
11 Years	7,796,251	7,864,125
% Difference	0.59%	0.59%

Enersource utilizes hourly weather information from the Lester B. Pearson International Airport ("Pearson Airport") weather station located in Mississauga. The data used for review, analysis and scenario development was obtained from the National Climate Data Archives at Environment Canada.[7] Enersource's study of normal and extreme weather data used the hourly data from Pearson Airport from 1980 to 2011.

Normal Weather Scenario Process

The process used by Enersource to derive its normal weather scenario involves ranking and selecting the median temperature for each day of the year. The process starts with converting historical hourly daily temperatures into daily mean (average) temperatures. Daily average temperatures are then indexed based on similar days in their respective week of the year. For each day of the week, the data was ranked from the highest (maximum) daily average temperature to lowest (minimum) daily average temperature. Based on a list of 31 daily average temperatures for the same day of the same week for each year, the median daily average temperature is selected. This process is repeated for each day of the year to build an entire year of normal weather data.

[7] http://climate.weatheroffice.gc.ca

Extreme Weather Scenario Process

The process used to derive the extreme weather scenario is similar to that used to derive the normal weather scenario. However, rather than selecting the median daily average temperature for each day, the extreme weather scenario uses the maximum daily average temperature during summer months and the minimum daily average temperature for the winter months.

Weather Normalization for Rate Class Sales

Enersource has developed multivariate regression models to determine energy consumption for each rate class. These models capture the relationship between rate class sales and a number of explanatory variables including weather, calendar, econometric and other explanatory variables. The models were developed based on energy sales from 2004 to 2011 and include the same input variables such as weather, calendar, and econometric data as the system energy and peak demand models. The models were then used to derive weather-corrected energy sales for each rate class using the normal weather scenario.

Class sales models were created for the following customer groups:

- Residential;
- Small Commercial;
- General Service Less Than 50 kW;
- General Service 50-499 kW;
- General Service 500-4999 kW; and
- Large User.

Actual and forecast energy sales in kWh for all rate classes for 2008 through 2013, net of CDM adjustments, are provided at Attachment 2. Weather-normalized actual and forecast energy monthly sales in kWh for all rate classes for 2008 through 2013 are provided at Attachment 3.

Similarly, actual and forecast energy demand for all applicable rate classes for 2008 to 2013 is provided at Attachment 4. Weather-normalized actual and forecast energy demand for all applicable rate classes for 2008 to 2013 is provided at Attachment 5. Energy demand forecasts were determined by applying weather-normalized energy sales to a five-year average load factor by customer rate class to determine weather-normalized billing determinants in kW by customer rate class.

The weather-normalized rate class sales models performed very well, with adjusted R^2 statistics ranging from 0.83 to 0.95 and MAPE of 1.25% to 2.31%. The model statistics and a list of coefficient variables for each rate class model, including standard error, T-statistics and P-values, can be found at Appendix C to Appendix H.

Historical Performance of Load Forecasting

Table 6 below provides a comparison of forecasted, actual and weather-normalized energy consumption from 2004 to 2011. When adjusted for annual incremental energy savings as a result of Enersource's CDM activities, the forecasted energy consumption was found to have an average variance of 0.33% compared to actual energy consumption. Likewise, the forecasted energy consumption was found to vary from the weather-corrected energy consumption by 1.72%. On average, Enersource's consumption forecasts tended to exceed actual energy consumption.

Table 6: Forecast Performance Vs. Actual and Weather-Corrected Energy Consumption, 2004 to 2011 (MWh)

Year	Forecast Energy Consumption (MWh)	Actual Energy Consumption (MWh)	Variance of Forecasted to Actual Energy (%)	Actual Consumption Weather-Corrected (MWh)	Variance of Forecasted to Actual W/C Energy (%)
2004	7,898,226	7,940,668	-0.54	7,906,647	-0.11
2005	8,021,757	8,281,072	-3.23	8,024,379	-0.03
2006	8,153,097	8,038,676	1.40	8,035,586	1.44
2007	8,244,528	8,249,692	-0.06	8,052,075	2.33
2008	8,234,669	8,096,552	1.68	7,995,947	2.90
2009	8,064,633	7,742,344	4.00	7,788,628	3.42
2010	7,866,814	7,949,146	-1.05	7,739,098	1.62
2011	7,914,667	7,880,490	0.43	7,744,998	2.14
		Average	**0.33**		**1.72**

The higher variances since 2008 are largely attributable to the use of projected econometric drivers from the Province Of Ontario's Economic Outlook and Fiscal Plan that supports the annual Ontario Budget. Since late 2011, Enersource has begun using the Conference Board of Canada's outlook for the region of Toronto, which includes Mississauga. This change was a result of an analaysis of Enersource's historical load forecasting performance. Based on revised inputs using the Conference Board of Canada outlooks, the performance of Enersource's load forecasting model was much-improved. The predicted results of the models, when adjusted for annual incremental CDM savings, was found to have a variance of -0.10% to actual energy consumption, and 1.27% compared to weather-corrected energy consumption as illustrated in Table 7 below.

Table 7: Revised Predicted Performance Vs. Actual and Weather-Corrected Energy Consumption, 2004 to 2011 (MWh)

Year	Predicted Energy Consumption (MWh)	Actual Energy Consumption (MWh)	Variance of Predicted to Actual Energy (%)	Actual Weather-Corrected Consumption (MWh)	Variance of Predicted to Actual W/C Energy (%)
2004	7,921,123	7,940,668	-0.25	7,906,647	0.18
2005	8,324,628	8,281,072	0.52	8,024,379	3.61
2006	8,101,047	8,038,676	0.77	8,035,586	0.81
2007	8,219,132	8,249,692	-0.37	8,052,075	2.03
2008	8,038,984	8,096,552	-0.72	7,995,947	0.54
2009	7,738,025	7,742,344	-0.06	7,788,628	-0.65
2010	7,889,814	7,949,146	-0.75	7,739,098	1.91
2011	7,882,301	7,880,490	0.02	7,744,998	1.74
		Average	-0.10		1.27

Customer Number Forecast

The City of Mississauga ("City" or "Mississauga") currently has an estimated population of 737,000 residents. The City (and Enersource in parallel) went through a very aggressive expansion period spanning the mid-1980's to the mid-2000's. More recently, Enersource's expansion has slowed relative to the past periods, and available greenfield space for further development has been significantly reduced. Population growth will be driven primarily through intensification and the City has become more focused on higher density housing forms, particularly apartment and condominium development.

Enersource has relied on historical data and information obtained from the City's Planning Department as well as Enersource's own internal measures of development and building service applications to forecast projections for customer growth. Actual and forecasted customer numbers by rate class are provided at Attachments 6 and 7 for 2007 through 2013. Attachment 6 provides the annual average customer numbers for 2007 to 2013. Attachment 7 provides the year-end number of customers for the same period.

As shown in Attachment 6, Enersource anticipates annual growth rates of 1.3% and 1.2% in its average number of customers for the 2012 Bridge Year and 2013 Test Year, respectively.

As shown in Attachment 7, the number of customers at year-end has grown by an average of 2,821 per year from 2008 to 2011. For the 2012 Bridge Year and the 2013 Test Year, an additional 2,683 and 2,229 customers are forecast at year-end, respectively.

Attachment A – Short Term System Load Energy Model Statistics

Regression Statistics	
Iterations	18
Adjusted Observations	191
Deg. of Freedom for Error	173
R-Squared	0.988
Adjusted R-Squared	0.987
AIC	17.914
BIC	18.221
Log-Likelihood	-1,963.83
Model Sum of Squares	790,516,390,955.78
Sum of Squared Errors	9,533,001,678.53
Mean Squared Error	55,104,055.95
Std. Error of Regression	7,423.21
Mean Abs. Dev. (MAD)	5,413.50
Mean Abs. % Err. (MAPE)	0.86%
Durbin-Watson Statistic	2.092
Ljung-Box Statistic	35.95
Prob (Ljung-Box)	0.0556
Skewness	-0.168
Kurtosis	3.291
Jarque-Bera	1.577
Prob (Jarque-Bera)	0.4546

Variable	Coefficient	StdErr	T-Stat	P-Value
Monthly.MonthlyTimeTrend	-18692.675	1373.18	-13.613	0.00%
Population.Population	-0.271	0.063	-4.323	0.00%
Employment.EmpLand	0.573	0.156	3.673	0.03%
Employment.MajOff	6.305	0.507	12.441	0.00%
Monthly.MonthlyGDP	2.849	0.77	3.698	0.03%
MonthlyWeather.MonthlyDBCubed	-0.239	0.081	-2.958	0.35%
MonthlyWeather.MonthlyBuildUp	137.917	39.549	3.487	0.06%
MonthlyWeather.MonthlyCDD	1042.732	93.13	11.196	0.00%
MonthlyWeather.MonthlyHDD	323.34	36.225	8.926	0.00%
Monthly.WorkingDays	2889.973	464.444	6.222	0.00%
MonthlyWeather.MonthlyDwPtCubed	0.15	0.04	3.759	0.02%
MonthlyCalTrans.Month_Feb	-37044.965	2849.082	-13.002	0.00%
MonthlyCalTrans.Month_Aug2003	-4312.616	635.232	-6.789	0.00%
MonthlyCalTrans.Month_Apr	-18234.514	2706.349	-6.738	0.00%
MonthlyCalTrans.Month_Nov1996	-24857.429	6776.573	-3.668	0.03%
MonthlyCalTrans.Month_Dec1999	24056.334	6797.63	3.539	0.05%
AR(1)	0.292	0.076	3.831	0.02%
SMA(1)	0.352	0.078	4.522	0.00%

Attachment B – Short Term System Load Peak Model Statistics

Regression Statistics	
Iterations	10
Adjusted Observations	5842
Deg. of Freedom for Error	5821
R-Squared	0.950
Adjusted R-Squared	0.949
AIC	7.066
BIC	7.090
F-Statistic	5476.454
Prob (F-Statistic)	0.0000
Log-Likelihood	(28,908.71)
Model Sum of Squares	127,869,833.91
Sum of Squared Errors	6,795,732.00
Mean Squared Error	1,167.45
Std. Error of Regression	34.17
Mean Abs. Dev. (MAD)	24.16
Mean Abs. % Err. (MAPE)	2.46%
Durbin-Watson Statistic	2.021
Ljung-Box Statistic	708.89
Prob (Ljung-Box)	0.0000
Skewness	-0.031
Kurtosis	10.213
Jarque-Bera	12664.175
Prob (Jarque-Bera)	0.0000

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	228.958	20.769	11.024	0.00%
EconomicDrivers.CPI	248.104	22.777	10.893	0.00%
Calendar.TWT	12.287	1.204	10.205	0.00%
EconomicDrivers.Employment_Land	0.003	0.000	21.081	0.00%
WeatherTrans.AveDB	4.726	0.502	9.409	0.00%
WeatherTrans.MaxDB	1.064	0.268	3.967	0.01%
WeatherTrans.BuildUp	-0.945	0.172	-5.505	0.00%
WeatherTrans.CDD	26.157	0.822	31.819	0.00%
WeatherTrans.HDD	9.971	0.430	23.209	0.00%
WeatherTrans.XCDD	4.898	1.117	4.386	0.00%
WeatherTrans.LaggCDD	8.028	0.495	16.207	0.00%
SunTime.HoursOfLight	-10.583	0.926	-11.428	0.00%
Daily.WkEnd	-151.266	1.255	-120.565	0.00%
Daily.Aug2003	-37.712	16.024	-2.353	1.86%
CalTrans.AugWkDay	50.029	3.448	14.511	0.00%
CalTrans.SeptWkDay	27.922	3.384	8.253	0.00%
CalTrans.JulWkDay	49.262	3.402	14.481	0.00%
CalTrans.OfficeHolidays	11.237	3.017	3.725	0.02%
AR(1)	0.487	0.013	36.539	0.00%
AR(2)	0.134	0.013	10.131	0.00%
SMA(1)	0.241	0.013	18.558	0.00%

Attachment C – Short Term Rate Class Model Statistics – Residential

Regression Statistics	
Iterations	1
Adjusted Observations	32
Deg. of Freedom for Error	24
R-Squared	0.963
Adjusted R-Squared	0.952
AIC	19.423
BIC	19.790
Log-Likelihood	(348.18)
Model Sum of Squares	135,900,847,872.91
Sum of Squared Errors	5,289,122,416.51
Mean Squared Error	220,380,100.69
Std. Error of Regression	14,845.20
Mean Abs. Dev. (MAD)	9,383.41
Mean Abs. % Err. (MAPE)	2.31%
Durbin-Watson Statistic	2.377
Ljung-Box Statistic	7.39
Prob (Ljung-Box)	0.4947
Skewness	0.407
Kurtosis	3.775
Jarque-Bera	1.685
Prob (Jarque-Bera)	0.4306

Variable	Coefficient	StdErr	T-Stat	P-Value
Q_Weather.Q_CDD	764.700	31.318	24.418	0.00%
Q_Weather.Q_HDD	132.434	8.189	16.172	0.00%
Q_EconDrivers.Q_Population	0.378	0.010	38.149	0.00%
Q_CalTrans.Q2_2005	-34372.503	15288.831	-2.248	3.40%
Q_CalTrans.Q3_2008	34237.981	15450.013	2.216	3.64%
Q_CalTrans.Q2_2007	-15612.602	15306.779	-1.020	3.79%
Q_CalTrans.Q4_2009	29870.666	15395.935	1.940	6.42%
Q_CalTrans.Q_Year2004	19462.189	8010.093	2.430	2.30%

Attachment D – Short Term Rate Class Model Statistics – Small Commercial

Regression Statistics	
Iterations	37
Adjusted Observations	32
Deg. of Freedom for Error	23
R-Squared	0.959
Adjusted R-Squared	0.945
AIC	8.373
BIC	8.785
Log-Likelihood	(170.37)
Model Sum of Squares	1,851,603.18
Sum of Squared Errors	78,920.24
Mean Squared Error	3,431.31
Std. Error of Regression	58.58
Mean Abs. Dev. (MAD)	37.50
Mean Abs. % Err. (MAPE)	1.25%
Durbin-Watson Statistic	1.307
Ljung-Box Statistic	11.23
Prob (Ljung-Box)	0.1887
Skewness	0.405
Kurtosis	3.511
Jarque-Bera	1.224
Prob (Jarque-Bera)	0.5422

Variable	Coefficient	StdErr	T-Stat	P-Value
Q_CalTrans.Q_TimeTrend	-25.847	5.670	-4.559	0.01%
Q_Weather.Q_AveDB	0.020	0.002	11.827	0.00%
EconomicIndicators.CPI	2786.183	4.983	559.084	0.00%
Q_CalTrans.Q4_2005	808.373	23.699	34.111	0.00%
Q_CalTrans.Q4_2007	-336.632	135.728	-2.480	2.09%
Q_CalTrans.Q3_2009	-674.028	147.716	-4.563	0.01%
Q_CalTrans.Q4_2009	-426.682	142.180	-3.001	0.64%
Q_CalTrans.Q3_2010	-794.230	149.602	-5.309	0.00%
SMA(1)	-2.415	0.058	-41.752	0.00%

Attachment E – Short Term Rate Class Model Statistics – General Service Less Than 50kW

Regression Statistics	
Iterations	11
Adjusted Observations	31
Deg. of Freedom for Error	24
R-Squared	0.863
Adjusted R-Squared	0.829
AIC	16.138
BIC	16.462
Log-Likelihood	(287.12)
Model Sum of Squares	1,269,715,582.57
Sum of Squared Errors	201,257,129.28
Mean Squared Error	8,385,713.72
Std. Error of Regression	2,895.81
Mean Abs. Dev. (MAD)	1,889.21
Mean Abs. % Err. (MAPE)	1.10%
Durbin-Watson Statistic	1.920
Ljung-Box Statistic	12.73
Prob (Ljung-Box)	0.1215
Skewness	0.001
Kurtosis	3.419
Jarque-Bera	0.226
Prob (Jarque-Bera)	0.8929

Variable	Coefficient	StdErr	T-Stat	P-Value
Q_CalTrans.Q_TimeTrend	-3324.979	220.242	-15.097	0.00%
EconomicIndicators.CPI	155292.199	1671.045	92.931	0.00%
Q_Weather.Q_CDD	51.889	7.314	7.094	0.00%
Q_Weather.Q_HDD	17.811	1.991	8.946	0.00%
Q_CalTrans.Q_Year2011	-8562.512	1620.425	-5.284	0.00%
Q_CalTrans.Q1_2011	9707.459	3454.548	2.810	0.97%
AR(1)	-0.382	0.183	-2.084	4.80%

Attachment F – Short Term Rate Class Model Statistics – General Service 50-499kW

Regression Statistics	
Iterations	1
Adjusted Observations	32
Deg. of Freedom for Error	24
R-Squared	0.909
Adjusted R-Squared	0.883
AIC	19.021
BIC	19.388
Log-Likelihood	(341.75)
Model Sum of Squares	35,458,613,737.04
Sum of Squared Errors	3,538,618,101.55
Mean Squared Error	147,442,420.90
Std. Error of Regression	12,142.59
Mean Abs. Dev. (MAD)	8,526.45
Mean Abs. % Err. (MAPE)	1.49%
Durbin-Watson Statistic	1.988
Ljung-Box Statistic	6.11
Prob (Ljung-Box)	0.6350
Skewness	-0.047
Kurtosis	2.036
Jarque-Bera	1.250
Prob (Jarque-Bera)	0.5352

Variable	Coefficient	StdErr	T-Stat	P-Value
Q_CalTrans.Q_TimeTrend	-22927.084	1142.967	-20.059	0.00%
EconomicIndicators.CPI	579044.308	7713.878	75.065	0.00%
Q_Weather.Q_CDD	97.614	26.379	3.701	0.11%
Q_Weather.Q_HDD	45.392	7.231	6.277	0.00%
Q_CalTrans.Q2_2006	-53885.942	12862.215	-4.189	0.03%
Q_CalTrans.Q1_2010	-24960.592	12927.060	-1.931	6.54%
Q_CalTrans.Q1_2006	31420.903	12734.248	2.467	2.11%
Q_CalTrans.Q2_2004	-30208.051	13623.602	-2.217	3.63%

Attachment G – Short Term Rate Class Model Statistics – General Service 500-4999kW

Regression Statistics	
Iterations	1
Adjusted Observations	32
Deg. of Freedom for Error	24
R-Squared	0.898
Adjusted R-Squared	0.869
AIC	18.806
BIC	19.172
Log-Likelihood	(338.30)
Model Sum of Squares	25,239,450,344.15
Sum of Squared Errors	2,852,229,979.36
Mean Squared Error	118,842,915.81
Std. Error of Regression	10,901.51
Mean Abs. Dev. (MAD)	7,252.23
Mean Abs. % Err. (MAPE)	1.25%
Durbin-Watson Statistic	1.763
Ljung-Box Statistic	5.49
Prob (Ljung-Box)	0.7038
Skewness	-0.092
Kurtosis	2.683
Jarque-Bera	0.179
Prob (Jarque-Bera)	0.9142

Variable	Coefficient	StdErr	T-Stat	P-Value
Q_CalTrans.Q_TimeTrend	-15283.215	1963.543	-7.783	0.00%
EconomicIndicators.CPI	-865520.175	125837.516	-6.878	0.00%
Q_Weather.Q_AveDB	16.736	2.513	6.659	0.00%
Q_EconDrivers.Q_TotalMajOff	8.471	1.670	5.073	0.00%
EconomicIndicators.GDP	3.682	0.660	5.579	0.00%
Q_CalTrans.Q3_2005	-28689.700	11783.883	-2.435	2.27%
Q_CalTrans.Q4_2005	27434.077	11329.100	2.422	2.34%
Q_CalTrans.Q2_2007	30297.268	11419.169	2.653	1.39%

Attachment H – Short Term Rate Class Model Statistics – Large User

Regression Statistics	
Iterations	99
Adjusted Observations	32
Deg. of Freedom for Error	22
R-Squared	0.936
Adjusted R-Squared	0.910
AIC	17.112
BIC	17.570
Log-Likelihood	(309.20)
Model Sum of Squares	6,814,771,577.35
Sum of Squared Errors	462,683,639.01
Mean Squared Error	21,031,074.50
Std. Error of Regression	4,585.96
Mean Abs. Dev. (MAD)	3,223.09
Mean Abs. % Err. (MAPE)	1.26%
Durbin-Watson Statistic	2.220
Ljung-Box Statistic	7.01
Prob (Ljung-Box)	0.5352
Skewness	-0.211
Kurtosis	2.035
Jarque-Bera	1.479
Prob (Jarque-Bera)	0.4773

Variable	Coefficient	StdErr	T-Stat	P-Value
Q_Weather.Q_HDD	-24.732	2.759	-8.963	0.00%
Q_Weather.Q_CDD	-36.251	9.535	-3.802	0.10%
EconomicIndicators.GDP	0.992	0.100	9.870	0.00%
Q_EconDrivers.Q_NumberLU	6244.775	2256.954	2.767	1.12%
Q_CalTrans.Q_Year2011	-18788.699	5988.308	-3.138	0.48%
Q_CalTrans.Q1_2004	26286.846	4144.135	6.343	0.00%
Q_CalTrans.Q3_2005	-15865.781	5715.458	-2.776	1.10%
Q_CalTrans.Q4_2007	23012.947	5571.305	4.131	0.04%
Q_CalTrans.Q3_2006	-14036.538	5486.102	-2.559	1.79%
MA(1)	1.450	0.238	6.090	0.00%

Attachment I – Monthly System Energy Consumption and Peak Demand Results, Actual and Weather-Corrected, 1997 to 2011

Month	Actual Energy Consumption (MWh)	Weather-Corrected Consumption (MWh)	Weather Correction – Consumption (MWh)		Actual Peak Demand (MW)	Weather-Corrected Peak (MW)	Weather Correction - Peak (MW)
Jan-97	591,610	588,234	3,376		992	950	41
Feb-97	523,702	531,179	-7,477		962	939	23
Mar-97	545,585	540,775	4,810		922	886	36
Apr-97	513,752	490,984	22,768		893	901	-8
May-97	504,262	500,748	3,514		854	849	5
Jun-97	558,780	530,474	28,306		1,211	976	236
Jul-97	604,731	614,077	-9,346		1,256	1,064	192
Aug-97	558,571	574,729	-16,158		1,041	1,054	-13
Sep-97	516,623	513,095	3,527		968	949	19
Oct-97	530,956	517,759	13,197		927	856	70
Nov-97	547,008	541,707	5,301		976	974	2
Dec-97	576,496	575,561	935		1,009	977	32
Jan-98	585,118	600,240	-15,122		1,005	982	23
Feb-98	523,095	541,217	-18,122		964	957	7
Mar-98	570,073	564,461	5,612		948	923	25
Apr-98	505,489	509,318	-3,829		880	962	-83
May-98	537,853	509,272	28,581		1,084	870	214
Jun-98	582,393	548,610	33,782		1,234	1,060	174
Jul-98	629,387	625,433	3,954		1,283	1,093	189
Aug-98	633,247	591,434	41,813		1,242	1,074	167
Sep-98	562,308	525,137	37,172		1,116	963	152
Oct-98	534,822	530,552	4,270		917	900	17
Nov-98	551,434	560,364	-8,930		970	999	-29
Dec-98	578,814	591,808	-12,994		1,039	1,013	26
Jan-99	600,424	612,446	-12,023		1,042	997	45
Feb-99	529,880	551,932	-22,052		980	977	3
Mar-99	570,446	585,402	-14,956		941	953	-12
Apr-99	512,921	515,577	-2,656		890	948	-59
May-99	536,202	524,622	11,580		1,032	921	111
Jun-99	620,353	565,053	55,300		1,259	1,065	194
Jul-99	687,947	645,763	42,183		1,344	1,136	208
Aug-99	611,838	605,373	6,465		1,163	1,121	42
Sep-99	573,254	548,446	24,807		1,157	1,050	108
Oct-99	547,026	546,523	504		926	944	-18
Nov-99	561,078	583,605	-22,527		1,008	1,042	-34
Dec-99	619,204	629,376	-10,172		1,088	1,059	29
Jan-00	629,285	628,890	395		1,074	1,006	68
Feb-00	583,255	581,329	1,926		1,034	1,003	31
Mar-00	585,126	602,890	-17,764		965	963	2
Apr-00	540,107	534,229	5,878		952	979	-27
May-00	572,602	552,006	20,595		1,129	917	212
Jun-00	595,751	591,757	3,994		1,218	1,083	135
Jul-00	628,485	660,502	-32,017		1,186	1,159	27
Aug-00	652,999	636,660	16,340		1,300	1,105	195
Sep-00	589,437	560,388	29,048		1,305	1,062	243
Oct-00	576,968	569,553	7,415		986	933	53
Nov-00	592,190	598,380	-6,190		1,082	1,037	45
Dec-00	647,661	620,917	26,744		1,124	1,077	47
Jan-01	649,509	655,478	-5,969		1,091	1,064	27

Month	Actual Energy Consumption (MWh)	Weather-Corrected Consumption (MWh)	Weather Correction – Consumption (MWh)		Actual Peak Demand (MW)	Weather-Corrected Peak (MW)	Weather Correction - Peak (MW)
Feb-01	582,294	600,546	-18,252		1,060	1,038	21
Mar-01	627,174	620,017	7,157		1,044	1,001	43
Apr-01	557,728	555,172	2,556		970	988	-18
May-01	584,419	570,348	14,071		1,105	960	145
Jun-01	645,564	606,350	39,213		1,373	1,144	230
Jul-01	659,492	688,672	-29,180		1,373	1,190	183
Aug-01	722,902	649,346	73,556		1,477	1,152	325
Sep-01	602,684	577,973	24,711		1,189	1,107	83
Oct-01	602,304	590,507	11,797		1,045	981	64
Nov-01	597,480	618,689	-21,210		1,062	1,064	-2
Dec-01	624,215	634,345	-10,130		1,090	1,091	-1
Jan-02	654,337	676,202	-21,865		1,088	1,101	-13
Feb-02	594,862	610,097	-15,235		1,115	1,073	42
Mar-02	632,565	632,902	-337		1,077	1,033	44
Apr-02	599,937	579,240	20,698		1,108	1,025	83
May-02	613,199	589,820	23,379		1,130	986	144
Jun-02	654,990	625,769	29,221		1,402	1,151	251
Jul-02	781,059	702,739	78,320		1,509	1,198	312
Aug-02	745,061	671,846	73,216		1,493	1,230	263
Sep-02	673,569	604,228	69,341		1,474	1,055	418
Oct-02	632,948	609,156	23,792		1,221	1,006	215
Nov-02	635,185	633,483	1,702		1,117	1,066	51
Dec-02	668,269	658,540	9,729		1,185	1,116	69
Jan-03	704,264	694,348	9,916		1,185	1,118	67
Feb-03	639,371	627,924	11,447		1,164	1,101	63
Mar-03	660,612	651,336	9,276		1,143	1,057	87
Apr-03	612,394	592,264	20,131		1,071	1,081	-10
May-03	611,207	605,414	5,793		1,055	1,014	40
Jun-03	651,350	640,510	10,840		1,505	1,199	306
Jul-03	721,223	723,382	-2,160		1,400	1,278	122
Aug-03	683,386	633,952	49,435		1,416	1,264	152
Sep-03	621,515	615,318	6,196		1,164	1,125	40
Oct-03	622,719	618,084	4,635		1,062	1,032	30
Nov-03	630,346	643,229	-12,882		1,117	1,087	30
Dec-03	670,992	674,304	-3,311		1,165	1,138	27
Jan-04	714,721	699,495	15,226		1,215	1,143	72
Feb-04	653,440	642,562	10,878		1,149	1,137	12
Mar-04	671,008	676,176	-5,168		1,120	1,079	42
Apr-04	617,241	602,773	14,468		1,064	1,034	29
May-04	626,305	616,861	9,444		1,173	1,045	129
Jun-04	647,295	654,031	-6,735		1,408	1,211	197
Jul-04	693,708	728,462	-34,754		1,427	1,252	175
Aug-04	689,041	690,333	-1,292		1,379	1,260	119
Sep-04	661,780	626,430	35,349		1,250	1,135	115
Oct-04	632,872	625,970	6,902		1,095	1,056	39
Nov-04	642,602	662,548	-19,947		1,141	1,109	31
Dec-04	690,656	681,007	9,649		1,241	1,165	75
Jan-05	722,204	710,922	10,167		1,226	1,160	65
Feb-05	640,160	659,431	-19,735		1,151	1,141	11
Mar-05	686,159	673,684	12,647		1,139	1,104	34
Apr-05	618,570	620,660	-4,485		1,050	1,075	-24
May-05	628,143	621,397	6,355		1,081	1,048	33
Jun-05	752,502	661,549	93,803		1,539	1,222	316
Jul-05	799,213	731,427	62,298		1,570	1,286	284
Aug-05	767,434	706,446	60,413		1,510	1,235	275
Sep-05	674,926	636,706	37,714		1,360	1,183	177

Month	Actual Energy Consumption (MWh)	Weather-Corrected Consumption (MWh)	Weather Correction – Consumption (MWh)		Actual Peak Demand (MW)	Weather-Corrected Peak (MW)	Weather Correction - Peak (MW)
Oct-05	645,451	637,286	9,362		1,197	1,066	131
Nov-05	650,477	667,724	-16,538		1,166	1,121	45
Dec-05	695,833	697,148	1,071		1,220	1,173	47
Jan-06	691,094	720,489	-29,288		1,171	1,176	-5
Feb-06	640,465	655,079	-14,745		1,158	1,150	9
Mar-06	683,758	684,746	-454		1,124	1,124	1
Apr-06	599,753	613,981	-13,429		1,052	1,066	-14
May-06	649,367	627,435	22,633		1,510	1,064	446
Jun-06	696,076	666,768	29,551		1,418	1,257	161
Jul-06	784,270	737,948	46,096		1,580	1,329	251
Aug-06	734,961	705,704	29,103		1,610	1,334	276
Sep-06	627,769	634,797	-7,656		1,193	1,177	15
Oct-06	641,867	635,797	5,737		1,084	1,090	-6
Nov-06	647,119	666,636	-19,842		1,137	1,148	-11
Dec-06	672,462	686,204	-14,396		1,202	1,170	32
Jan-07	710,918	719,607	-8,896		1,220	1,174	46
Feb-07	669,445	656,595	12,610		1,238	1,158	80
Mar-07	683,515	685,335	-1,362		1,161	1,106	55
Apr-07	630,317	614,253	16,582		1,096	1,087	9
May-07	652,766	632,107	20,982		1,300	1,088	212
Jun-07	719,099	665,413	53,456		1,556	1,245	312
Jul-07	730,275	740,770	-10,279		1,556	1,311	245
Aug-07	769,376	708,670	60,801		1,560	1,370	190
Sep-07	667,392	630,939	36,105		1,462	1,119	344
Oct-07	657,751	641,470	19,986		1,174	1,058	116
Nov-07	665,955	669,182	-3,889		1,175	1,137	38
Dec-07	692,882	687,735	5,563		1,205	1,169	36
Jan-08	709,652	719,501	-10,039		1,195	1,223	-28
Feb-08	665,058	659,913	5,335		1,200	1,164	36
Mar-08	680,374	677,966	2,275		1,124	1,115	9
Apr-08	622,890	616,931	5,959		1,078	1,132	-54
May-08	628,307	627,091	1,217		1,135	1,094	41
Jun-08	690,516	658,901	31,606		1,513	1,241	272
Jul-08	749,569	736,309	13,256		1,471	1,323	148
Aug-08	706,433	699,100	7,333		1,381	1,324	56
Sep-08	660,621	637,081	23,540		1,379	1,153	226
Oct-08	644,486	631,776	12,710		1,079	1,077	2
Nov-08	647,496	653,176	-5,679		1,157	1,142	15
Dec-08	691,149	678,203	12,946		1,200	1,169	31
Jan-09	709,322	698,686	10,636		1,193	1,184	10
Feb-09	619,803	632,749	-11,508		1,181	1,160	21
Mar-09	662,783	655,551	7,232		1,156	1,135	21
Apr-09	594,357	604,632	-10,274		1,066	1,069	-2
May-09	601,189	596,937	4,371		1,125	1,060	66
Jun-09	639,917	639,868	115		1,394	1,220	174
Jul-09	661,873	725,360	-63,513		1,208	1,323	-115
Aug-09	709,006	685,100	23,906		1,506	1,294	211
Sep-09	633,269	615,463	17,811		1,207	1,206	1
Oct-09	626,309	618,996	7,316		1,041	1,067	-26
Nov-09	617,383	644,817	-27,434		1,095	1,175	-79
Dec-09	667,132	670,468	-3,321		1,149	1,167	-18
Jan-10	691,770	686,775	4,995		1,168	1,146	23
Feb-10	623,690	629,306	-5,617		1,140	1,138	2
Mar-10	643,430	664,970	-21,525		1,055	1,099	-44
Apr-10	589,692	595,231	-5,518		1,011	1,058	-47

Month	Actual Energy Consumption (MWh)	Weather-Corrected Consumption (MWh)	Weather Correction – Consumption (MWh)		Actual Peak Demand (MW)	Weather-Corrected Peak (MW)	Weather Correction - Peak (MW)
May-10	651,639	597,346	54,315		1,406	1,042	364
Jun-10	675,489	644,232	31,277		1,354	1,203	150
Jul-10	780,227	717,092	63,111		1,550	1,258	291
Aug-10	752,466	678,950	73,540		1,518	1,299	218
Sep-10	634,077	613,982	20,117		1,506	1,164	341
Oct-10	608,998	606,731	2,279		1,011	1,045	-34
Nov-10	627,864	638,998	-11,173		1,086	1,142	-55
Dec-10	669,803	665,485	4,413		1,183	1,157	26
Jan-11	701,079	687,983	13,099		1,174	1,151	23
Feb-11	628,060	627,236	829		1,154	1,137	16
Mar-11	659,056	658,378	703		1,088	1,105	-17
Apr-11	601,746	593,197	8,577		1,046	1,089	-43
May-11	616,436	603,044	13,410		1,241	1,095	145
Jun-11	657,499	643,095	14,404		1,424	1,247	176
Jul-11	786,007	712,716	73,292		1,609	1,318	292
Aug-11	729,979	685,346	44,633		1,385	1,298	86
Sep-11	634,092	611,335	22,757		1,307	1,199	108
Oct-11	618,879	607,536	11,343		1,052	1,043	10
Nov-11	608,435	647,392	-38,958		1,069	1,120	-51
Dec-11	639,222	667,740	-28,519		1,085	1,130	-45

Attachment 1
CDM Impacts on Load by Customer Class, 2012 and 2013

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2012													
Residential	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(1,892,417)	(22,709,000)
Small Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
Unmetered Scattered Load	-	-	-	-	-	-	-	-	-	-	-	-	-
GS < 50	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(2,718,384)	(32,620,613)
GS 50-499	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(362,488)	(4,349,853)
GS 500-4999	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(387,338)	(4,648,053)
Large User	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(1,226,235)	(14,714,815)
Street Lighting	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(435,733)	(5,228,799)
Total	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(7,022,594)**	**(84,271,133)**
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
2013													
Residential	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(2,986,910)	(35,842,920)
Small Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
Unmetered Scattered Load	-	-	-	-	-	-	-	-	-	-	-	-	-
GS < 50	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(3,293,274)	(39,519,293)
GS 50-499	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(559,884)	(6,718,613)
GS 500-4999	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(597,224)	(7,166,687)
Large User	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(748,638)	(8,983,655)
Street Lighting	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(1,742,933)	(20,915,195)
Total	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(9,928,864)**	**(119,146,362)**

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Attachment 2

Actual and Forecast Sales by Rate Class, Net of CDM Impact, 2008 to 2013 (kWh)

Year	Residential	Small Commercial	GS<50	GS 50-499	GS 499-5000	Large User	USL	SL	TOTAL
2008 COS	1,662,891,832	1,067,301	685,071,649	2,426,052,589	2,474,016,533	1,021,799,842	11,346,699	42,542,555	8,324,789,000
2008	1,590,715,319	939,264	698,622,742	2,298,548,871	2,384,183,548	1,071,190,323	10,924,769	40,809,194	8,095,934,029
2009	1,554,921,855	885,182	676,509,335	2,188,033,452	2,251,678,318	1,024,236,074	10,295,741	40,684,789	7,747,244,746
2010	1,643,433,648	944,558	684,916,468	2,207,381,098	2,286,532,969	1,087,915,337	10,986,351	41,020,740	7,963,131,169
2011	1,641,009,995	959,856	674,128,726	2,209,416,418	2,247,174,574	1,053,299,632	11,162,442	41,273,806	7,878,425,451
2012	1,475,529,071	908,655	634,432,107	2,199,706,127	2,312,319,691	996,912,190	10,663,801	34,990,190	7,665,461,831
2013	1,475,116,344	916,349	633,310,524	2,216,685,094	2,330,521,901	1,011,582,747	10,756,816	19,704,431	7,698,594,205

Note: Sales figures above include losses

Attachment 3

Actual and Forecast Weather-Normalized Sales by Rate Class, Net of CDM Impact, 2008 to 2013 (kWh)

Year	Residential	Small Commercial	GS<50	GS 50-499	GS 499-5000	Large User	USL	SL	TOTAL
2008 COS	1,662,891,832	1,067,301	685,071,649	2,426,052,589	2,474,016,533	1,021,799,842	11,346,699	42,542,555	8,324,789,000
2008	1,543,470,000	946,070	690,420,000	2,302,650,000	2,380,720,000	1,066,030,000	11,003,930	40,809,194	8,036,049,194
2009	1,547,830,000	890,651	673,500,000	2,222,330,000	2,266,880,000	1,038,590,000	10,359,349	40,684,789	7,801,064,789
2010	1,527,070,000	928,652	681,000,000	2,171,290,000	2,275,490,000	1,079,730,000	10,801,348	41,020,740	7,787,330,740
2011	1,534,980,000	964,425	667,480,000	2,187,200,000	2,240,390,000	1,054,640,000	11,215,575	41,271,191	7,738,141,191
2012	1,475,529,071	908,655	634,432,107	2,199,706,127	2,312,319,691	996,912,190	10,663,801	34,990,190	7,665,461,831
2013	1,475,116,344	916,349	633,310,524	2,216,685,094	2,330,521,901	1,011,582,747	10,756,816	19,704,431	7,698,594,205

Note: Sales figures above include losses

Attachment 4

Actual and Forecast Sales by Rate Class, Net of CDM Impact, 2008 to 2013 (kW)

Year	GS 50-499	GS 499-5000	Large User	SL	TOTAL
2008 COS	6,418,332	5,310,121	1,720,956	115,190	13,564,599
2008	6,355,155	5,277,864	1,842,419	109,605	13,585,043
2009	6,352,348	5,081,457	1,800,927	110,507	13,345,239
2010	6,303,886	5,084,891	1,831,545	111,465	13,331,786
2011	6,265,460	4,997,505	1,837,737	112,096	13,212,798
2012	6,092,264	5,113,673	1,712,059	93,639	13,011,635
2013	6,142,022	5,154,338	1,737,267	49,889	13,083,516

Note: Sales figures above include losses

Attachment 5

Actual and Forecast Weather-Normalized Sales by Rate Class, Net of CDM Impact, 2008 to 2013 (kW)

Year	GS 50-499	GS 499-5000	Large User	SL	TOTAL
2008 COS	6,418,332	5,310,121	1,720,956	115,190	13,564,599
2008	6,366,494	5,270,197	1,833,543	109,605	13,579,840
2009	6,451,919	5,115,763	1,826,166	110,507	13,504,355
2010	6,200,816	5,060,333	1,817,765	111,465	13,190,379
2011	6,202,459	4,982,417	1,840,076	112,089	13,137,040
2012	6,092,264	5,113,673	1,712,059	93,639	13,011,635
2013	6,142,022	5,154,338	1,737,267	49,889	13,083,516

Note: Sales figures above include losses

Attachment 6

Actual and Forecast Average Number of Customers &/or Connections by Rate Class, 2007 to 2013

Year	Residential	Small Commercial	GS<50	GS 50-499	GS 499-5000	Large User	Total	% Growth	USL	SL
2007	162,262	192	16,034	3,977	467	9	182,940		2,865	48,178
2008 COS	166,825	180	16,081	3,986	470	9	187,551		3,108	48,255
2008	164,329	175	16,181	3,954	469	10	185,116	1.2%	2,874	48,370
2009	167,085	177	16,471	3,912	482	10	188,136	1.6%	2,889	48,688
2010	169,768	174	16,730	3,991	483	10	191,156	1.6%	2,915	49,000
2011	172,346	170	17,000	3,986	472	11	193,983	1.5%	2,933	49,230
2012	174,659	168	17,287	3,947	464	10	196,534	1.3%	2,937	49,507
2013	176,865	168	17,534	3,950	464	9	198,990	1.2%	2,942	49,985

Note: Includes the impact of CDM

Attachment 7

Actual and Forecast Year-End Number of Customers &/or Connections by Rate Class, 2007 to 2013

Year	Residential	Small Commercial	GS<50	GS 50-499	GS 499-5000	Large User	Total	% Growth	USL	SL
2007	162,775	190	16,043	4,041	460	9	183,518		2,865	48,184
2008 COS	170,380	180	16,152	3,986	475	9	191,182		3,113	48,475
2008	165,882	177	16,318	3,867	477	10	186,731	1.8%	2,882	48,556
2009	168,288	176	16,624	3,956	486	10	189,540	1.5%	2,896	48,819
2010	171,247	172	16,836	4,026	480	10	192,771	1.7%	2,934	49,181
2011	173,444	168	17,163	3,945	463	11	195,194	1.3%	2,931	49,279
2012	175,874	168	17,412	3,948	464	9	197,875	1.4%	2,943	49,736
2013	177,856	168	17,657	3,951	464	9	200,104	1.1%	2,940	50,235

Note: Includes the impact of CDM

Variance Analysis

Introduction

Table 1 below provides a summary of the distribution revenue from 2008 to 2013 on an actual and weather-normalized basis. Further detail supporting Table 1 can be found at Attachments 1 to 11 of this exhibit.

Attachments 1 through 11 provide throughput revenue showing monthly detail of customer count by rate class, volumes (provides as both energy in kWh and demand in kW), rates, and revenues for the 2008 Approved COS, 2008 through 2011 actuals and weather-normalized 2012 Bridge Year forecast and 2013 Test Year forecast.

Throughput revenue for 2012 is calculated using the load forecast detailed in Exhibit 3 Tab 1 Schedules 1 and 2, and rates established in Exhibit 8 Tab 1 Schedule 1 before any cost allocation adjustments.

Table 1: Summary of Throughput Revenue, 2008 to 2013

	2008 Approved	2008 Actual	2008 Weather Normal	2009 Actual	2009 Weather Normal	2010 Actual	2010 Weather Normal	2011 Actual	2011 Weather Normal	2012 Bridge Year	2013 Test Year
Year-End Customers*	242,770	238,169	N/A	241,255	N/A	244,886	N/A	247,404	N/A	250,553	253,280
Billing Determinants - kWh	2,263,708,576	2,214,889,308	2,162,551,769	2,164,593,260	2,155,000,000	2,262,805,576	2,142,664,093	2,230,952,535	2,137,683,398	2,047,812,388	2,046,428,602
Billing Determinants - kW	13,564,599	13,585,043	$ 13,579,840	13,345,239	13,504,355	13,331,786	13,190,379	13,212,798	13,137,040	13,011,635	13,083,516
Distribution Revenue ($)	**114,688,998**	**112,512,285**	**111,906,879**	**114,381,051**	**,824,766**	**116,474,563**	**114,537,609**	**116,580,877**	**115,195,748**	**114,044,034**	**114,692,077**

* Includes Connections and Luminaires

Summary of Average Consumption Per Customer

Table 2 below shows weather-normalized average historical consumption per customer by rate class from the 2008 Approved COS, 2008 through 2011 actuals, the 2012 Bridge Year and the 2013 Test Year. From the 2008 Approved COS to 2011 actuals there is a decrease in average consumption/demand for each rate class. These decreases range from 1% in the "Small Commercial/Unmetered Scattered Loads" class, to 13% in the "Large User" customer class. This is primarily a direct result of unanticipated economic conditions that had been forecasted to remain strong in 2008 onward.

Table 2

Weather Normalized / Forecast Average Use By Customer Class, 2008 to 2013 (kWh per month)

Year	Residential	Small Commercial	GS<50	GS 50-499	GS 499-5000	Large User	USL	SL
2008 COS	831	494	3,550	134	942	15,935	304	0.20
2008	783	452	3,556	134	937	16,084	319	0.19
2009	772	421	3,408	137	885	15,218	299	0.19
2010	750	445	3,392	129	873	15,148	309	0.19
2011	742	473	3,272	130	881	14,604	319	0.19
2012	704	451	3,058	129	919	14,267	303	0.16
2013	695	455	3,010	130	926	16,086	305	0.08

Due to the economic downturn experienced in 2008 and 2009, load and demand grow has not reached these 2008 approved levels. Other factors contributing to the decline in load include conservation and demand management ("CDM") for residential and small general service ("GS < 50 kW") customers, and an increase in the number of large users at the 5 MW or greater level. From the 2011 actuals to the 2012 Bridge Year and 2013 Test Year, the most significant decrease in average consumption has been in the residential and GS < 50 kW customer classes where the average monthly consumption is forecasted to decrease by 6% and 8%, respectively. This is primarily a result of the aggressive CDM targets set for Enersource as a condition of its license.

Please note that the sales figures by rate class in Attachments 1 to 11 are the billing determinants and do not include losses.

ATTACHMENT 1
2008 BOARD APPROVED DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE /TOTAL
Customer/Connection Numbers													
RESIDENTIAL	163,271	163,917	164,563	165,209	165,855	166,501	167,147	167,793	168,439	169,086	169,733	170,380	166,825
GENERAL SERVICE <50	16,009	16,022	16,035	16,048	16,061	16,074	16,087	16,100	16,113	16,126	16,139	16,152	16,081
SMALL COMMERCIAL	180	180	180	180	180	180	180	180	180	180	180	180	180
UNMETERED SCATTERED LOAD	3,102	3,103	3,104	3,105	3,106	3,107	3,108	3,109	3,110	3,111	3,112	3,113	3,108
GENERAL SERVICE50 -499	3,986	3,986	3,986	3,986	3,986	3,986	3,986	3,986	3,986	3,986	3,986	3,986	3,986
GENERAL SERVICE 500-4999	475	442	465	469	472	472	473	473	474	474	474	475	470
LARGE USE	9	9	9	9	9	9	9	9	9	9	9	9	9
STREETLIGHTING	48,035	48,075	48,115	48,155	48,195	48,235	48,275	48,315	48,355	48,395	48,435	48,475	48,255
kWh or kW Sales													
RESIDENTIAL	149,330,484	139,010,717	128,802,130	116,481,334	108,420,648	109,991,254	158,571,623	185,071,596	151,792,243	119,571,214	98,595,921	129,149,183	1,594,788,347
GENERAL SERVICE<50	60,714,124	59,634,851	55,545,508	55,649,359	50,470,735	52,071,164	58,604,091	54,173,816	48,542,039	49,594,908	50,733,195	61,280,853	657,014,642
SMALLCOMMERCIAL	90,193	80,250	87,766	84,225	78,505	88,616	90,566	81,300	72,413	92,340	84,914	92,501	1,023,590
UNMETERED SCATTERED LOAD	958,864	853,157	933,056	895,416	834,608	942,091	962,825	864,321	769,832	981,687	902,742	983,398	10,881,997
GENERAL SERVICE 50-499	533,246	510,022	574,635	526,909	543,612	510,323	564,928	506,074	511,152	538,193	552,847	546,392	6,418,332
GENERAL SERVICE 500-4999	443,937	406,638	426,529	419,934	456,955	483,541	480,492	418,507	415,905	448,322	451,895	457,467	5,310,121
LARGE USE	151,138	129,751	136,722	134,005	149,665	156,106	139,744	153,044	116,455	148,338	163,426	142,561	1,720,956
STREETLIGHTING	10,075	9,291	9,317	9,949	9,177	9,427	8,633	10,143	8,997	9,186	10,577	10,416	115,190
Rates-Fixed Monthly($)													
RESIDENTIAL	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	
GENERAL SERVICE <50	38.98	38.98	38.98	38.98	38.98	38.98	38.98	38.98	38.98	38.98	38.98	38.98	
SMALL COMMERCIAL	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	
UNMETERED SCATTERED LOAD	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	
GENERAL SERVICE 50-499	68.21	68.21	68.21	68.21	68.21	68.21	68.21	68.21	68.21	68.21	68.21	68.21	
GENERAL SERVICE 500-4999	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	
LARGE USE	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	
STREETLIGHTING	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE /TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	
GENERAL SERVICE <50	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	
SMALL COMMERCIAL	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	
UNMETERED SCATTERED LOAD	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	
GENERAL SERVICE 50-499	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	
GENERAL SERVICE 500-4999	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	
LARGE USE	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	
STREETLIGHTING	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	
Revenue($)													
RESIDENTIAL	3,634,251	3,521,358	3,409,762	3,273,527	3,186,986	3,212,795	3,787,046	4,103,668	3,722,936	3,354,561	3,117,373	3,481,290	41,805,553
GENERAL SERVICE <50	1,316,172	1,304,375	1,258,263	1,259,954	1,201,424	1,220,176	1,295,158	1,245,160	1,181,464	1,193,973	1,207,457	1,328,207	15,011,782
SMALL COMMERCIAL	3,602	3,412	3,556	3,488	3,379	3,572	3,609	3,432	3,262	3,643	3,501	3,646	42,101
UNMETERED SCATTERED LOAD	50,699	48,691	50,227	49,519	48,368	50,431	50,837	48,966	47,172	51,229	49,732	51,283	597,154
GENERAL SERVICE 50-499	2,460,487	2,365,170	2,630,361	2,434,476	2,503,030	2,366,405	2,590,519	2,348,963	2,369,806	2,480,789	2,540,934	2,514,440	29,605,379
GENERAL SERVICE 500-4999	1,622,861	1,496,902	1,572,321	1,564,720	1,644,731	1,699,782	1,694,136	1,567,776	1,563,046	1,630,043	1,637,961	1,649,973	19,344,251
LARGE USE	552,926	491,911	511,799	504,048	548,722	567,098	520,419	558,363	453,979	544,937	587,981	528,457	6,370,640
STREETLIGHTING	163,827	156,024	156,340	162,722	155,043	157,597	149,692	164,868	153,447	155,389	169,376	167,814	1,912,139
TOTAL	9,804,825	9,387,843	9,592,628	9,252,453	9,291,683	9,277,854	10,091,416	10,041,195	9,495,112	9,414,564	9,314,315	9,725,109	114,688,998

ATTACHMENT 2
2008 ACTUAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	163,011	163,173	163,274	163,740	164,639	164,650	164,819	164,906	165,010	165,329	165,595	165,882	164,502
GENERAL SERVICE <50	16,094	16,093	16,072	16,294	16,305	16,279	16,294	16,299	16,299	16,279	16,285	16,318	16,243
SMALL COMMERCIAL	192	188	187	185	185	184	184	183	182	180	178	177	184
UNMETERED SCATTERED LOAD	2,876	2,879	2,881	2,881	2,884	2,887	2,885	2,881	2,873	2,872	2,872	2,882	2,879
GENERAL SERVICE 50-499	4,055	4,059	4,065	3,818	3,830	3,835	3,841	3,844	3,839	3,852	3,848	3,867	3,896
GENERAL SERVICE 500-4999	461	461	464	465	467	468	469	472	474	475	475	477	469
LARGE USE	9	9	9	9	10	10	10	10	10	10	10	10	10
STREETLIGHTING	48,362	48,399	48,397	48,433	48,431	48,434	48,432	48,426	48,432	48,453	48,471	48,556	48,436
kWh or kW Sales													
RESIDENTIAL	148,557,489	135,784,406	131,862,588	116,850,525	102,257,830	113,932,894	134,973,603	158,306,782	153,535,524	114,013,111	105,314,651	115,865,916	1,531,255,320
GENERAL SERVICE <50	59,158,461	56,267,896	58,770,931	59,234,435	48,145,806	56,123,285	58,211,577	56,882,474	53,482,087	49,878,221	54,882,294	61,005,778	672,043,245
SMALL COMMERCIAL	63,619	94,562	87,498	60,655	116,983	93,673	54,380	91,480	85,850	60,073	97,321	90,428	996,521
UNMETERED SCATTERED LOAD	676,342	1,005,311	930,211	644,837	1,243,673	995,854	578,120	972,543	912,694	638,647	1,034,637	961,354	10,594,222
GENERAL SERVICE 50-499	516,365	516,545	561,806	503,618	577,100	523,495	524,949	523,227	560,753	499,971	472,326	575,000	6,355,155
GENERAL SERVICE 500-4999	431,101	410,948	470,496	389,727	478,076	422,042	489,236	423,192	445,824	420,372	452,648	444,201	5,277,864
LARGE USE	149,576	129,096	164,200	139,019	176,873	148,033	173,284	143,898	162,844	149,307	148,028	158,261	1,842,419
STREETLIGHTING	8,878	8,584	10,460	8,278	9,871	9,018	9,146	8,347	9,342	9,004	8,872	9,805	109,605
Rates-Fixed Monthly($)													
RESIDENTIAL	11.05	11.05	11.05	11.05	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	
GENERAL SERVICE <50	28.65	28.65	28.65	28.65	38.98	38.98	38.98	38.98	38.98	38.98	38.98	38.98	
SMALL COMMERCIAL	14.04	14.04	14.04	14.04	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	
UNMETERED SCATTERED LOAD	14.04	14.04	14.04	14.04	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	
GENERAL SERVICE 50-499	72.96	72.96	72.96	72.96	68.21	68.21	68.21	68.21	68.21	68.21	68.21	68.21	
GENERAL SERVICE5 00-4999	1239.48	1239.48	1239.48	1239.48	1501.66	1501.66	□□01.66	1501.66	1501.66	1501.66	1501.66	1501.66	
LARGE USE	13246.26	13246.26	13246.26	13246.26	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	
STREETLIGHTING	0.36	0.36	0.36	0.36	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0111	0.0111	0.0111	0.0111	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	
GENERAL SERVICE <50	0.0149	0.0149	0.0149	0.0149	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	
SMALL COMMERCIAL	0.0257	0.0257	0.0257	0.0257	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	
UNMETERED SCATTERED LOAD	0.0257	0.0257	0.0257	0.0257	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	
GENERAL SERVICE 50-499	4.3900	4.3900	4.3900	4.3900	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	
GENERAL SERVICE 500-4999	1.6906	1.6906	1.6906	1.6906	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	
LARGE USE	2.7937	2.7937	2.7937	2.7937	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	
STREETLIGHTING	2.7462	2.7462	2.7462	2.7462	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	
Revenue($)													
RESIDENTIAL	3,450,260	3,310,269	3,267,852	3,106,368	3,104,583	3,241,308	3,489,443	3,763,450	3,708,832	3,250,117	3,151,427	3,278,204	40,122,112
GENERAL SERVICE <50	1,342,554	1,299,456	1,336,150	1,349,416	1,184,431	1,274,361	1,298,752	1,283,795	1,245,031	1,203,167	1,260,447	1,331,542	15,409,102
SMALL COMMERCIAL	4,331	5,070	4,874	4,156	4,166	3,710	2,960	3,658	3,540	3,027	3,717	3,575	46,783
UNMETERED SCATTERED LOAD	57,761	66,258	64,356	57,022	53,862	49,161	41,162	48,653	47,427	42,182	49,745	48,450	626,037
GENERAL SERVICE 50-499	2,562,697	2,563,775	2,762,910	2,489,442	2,629,836	2,410,166	2,416,544	2,409,681	2,563,359	2,314,777	2,201,038	2,623,739	29,947,964
GENERAL SERVICE 500-4999	1,300,219	1,266,150	1,370,539	1,235,231	1,680,470	1,567,204	1,706,332	1,575,566	1,624,924	1,574,295	1,640,402	1,626,104	18,167,436
LARGE USE	537,088	479,873	577,941	507,593	639,872	557,593	629,632	545,798	599,848	561,228	557,580	586,774	6,780,821
STREETLIGHTING	41,790	40,998	46,148	40,168	162,300	153,761	155,037	147,033	157,003	153,647	152,345	161,799	1,412,029
TOTAL	9,296,700	9,031,848	9,430,770	8,789,397	9,459,520	9,257,264	9,739,862	9,777,634	9,949,964	9,102,439	9,016,702	9,660,186	112,512,285

ATTACHMENT 3

2008 WEATHER NORMAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	163,011	163,173	163,274	163,740	164,639	164,650	164,819	164,906	165,010	165,329	165,595	165,882	164,502
GENERAL SERVICE <50	16,094	16,093	16,072	16,294	16,305	16,279	16,294	16,299	16,299	16,279	16,285	16,318	16,243
SMALL COMMERCIAL	192	188	187	185	185	184	184	183	182	180	178	177	184
UNMETERED SCATTERED LOAD	2,876	2,879	2,881	2,881	2,884	2,887	2,885	2,881	2,873	2,872	2,872	2,882	2,879
GENERAL SERVICE 50-499	4,055	4,059	4,065	3,818	3,830	3,835	3,841	3,844	3,839	3,852	3,848	3,867	3,896
GENERAL SERVICE 500-4999	461	461	464	465	467	468	469	472	474	475	475	477	469
LARGE USE	9	9	9	9	10	10	10	10	10	10	10	10	10
STREETLIGHTING	48,362	48,399	48,397	48,433	48,431	48,434	48,432	48,426	48,432	48,453	48,471	48,556	48,436
kWh or kW Sales													
RESIDENTIAL	142,955,068	131,249,902	125,044,208	112,712,323	102,068,897	112,096,219	134,790,818	152,779,695	149,365,097	110,840,444	102,492,020	109,833,766	1,486,228,457
GENERAL SERVICE <50	58,420,758	54,887,236	57,717,201	58,172,794	49,024,136	55,678,635	57,797,256	56,399,305	52,870,732	49,277,078	54,237,143	60,331,292	664,813,566
SMALL COMMERCIAL	58,348	86,715	80,230	55,624	98,151	87,152	50,441	84,954	79,628	55,842	90,256	83,874	911,215
UNMETERED SCATTERED LOAD	678,658	1,008,595	933,173	646,969	1,141,618	1,013,681	586,693	988,122	926,175	649,507	1,049,780	975,559	10,598,531
GENERAL SERVICE 50-499	517,287	517,466	562,808	504,516	578,130	524,429	525,886	524,161	561,754	500,863	473,168	576,026	6,366,494
GENERAL SERVICE5 00-4999	430,474	410,351	469,812	389,161	477,381	421,429	488,525	422,578	445,177	419,761	451,990	443,555	5,270,197
LARGE USE	148,856	128,474	163,409	138,349	176,021	147,320	172,449	143,205	162,059	148,588	147,315	157,499	1,833,543
STREETLIGHTING	8,878	8,584	10,460	8,278	9,871	9,018	9,146	8,347	9,342	9,004	8,872	9,805	109,605
Rates-Fixed Monthly($)													
RESIDENTIAL	11.05	11.05	11.05	11.05	11.59	11.59	11.59	11.59	11.59	11.59	11.59	11.59	
GENERAL SERVICE <50	28.65	28.65	28.65	28.65	38.98	38.98	38.98	38.98	38.98	38.98	38.98	38.98	
SMALL COMMERCIAL	14.04	14.04	14.04	14.04	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	
UNMETERED SCATTERED LOAD	14.04	14.04	14.04	14.04	10.44	10.44	10.44	10.44	10.44	10.44	10.44	10.44	
GENERAL SERVICE 50-499	72.96	72.96	72.96	72.96	68.21	68.21	68.21	68.21	68.21	68.21	68.21	68.21	
GENERAL SERVICE 500-4999	1239.48	1239.48	1239.48	1239.48	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	1501.66	
LARGE USE	13246.26	13246.26	13246.26	13246.26	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	13527.08	
STREETLIGHTING	0.36	0.36	0.36	0.36	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0111	0.0111	0.0111	0.0111	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	
GENERAL SERVICE <50	0.0149	0.0149	0.0149	0.0149	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	0.0114	
SMALL COMMERCIAL	0.0257	0.0257	0.0257	0.0257	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	
UNMETERED SCATTERED LOAD	0.0257	0.0257	0.0257	0.0257	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	0.0191	
GENERAL SERVICE 50-499	4.39	4.39	4.39	4.39	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	4.1043	
GENERAL SERVICE 500-4999	1.6906	1.6906	1.6906	1.6906	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	2.0482	
LARGE USE	2.7937	2.7937	2.7937	2.7937	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	2.8529	
STREETLIGHTING	2.7462	2.7462	2.7462	2.7462	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	10.0145	
Revenue($)													
RESIDENTIAL	3,388,073	3,259,936	3,192,168	3,060,434	3,102,372	3,219,819	3,487,305	3,698,783	3,660,038	3,212,996	3,118,403	3,207,627	39,607,954
GENERAL SERVICE <50	1,331,562	1,278,884	1,320,449	1,333,598	1,194,444	1,269,292	1,294,029	1,278,287	1,238,061	1,196,314	1,253,093	1,323,852	15,311,866
SMALL COMMERCIAL	4,195	4,868	4,687	4,027	3,806	3,586	2,884	3,533	3,421	2,946	3,582	3,450	44,986
UNMETERED SCATTERED LOAD	57,821	66,342	64,432	57,076	51,913	49,502	41,325	48,951	47,684	42,389	50,034	48,721	626,190
GENERAL SERVICE 50-499	2,566,742	2,567,821	2,767,310	2,493,387	2,634,062	2,414,000	2,420,388	2,413,513	2,567,465	2,318,438	2,204,497	2,627,950	29,995,573
GENERAL SERVICE 500-4999	1,299,160	1,265,140	1,369,384	1,234,274	1,679,048	1,565,948	1,704,876	1,574,307	1,623,598	1,573,044	1,639,055	1,624,782	18,152,616
LARGE USE	535,075	478,135	575,731	505,722	637,441	555,559	627,251	543,820	597,610	559,176	555,545	584,599	6,755,666
STREETLIGHTING	41,790	40,998	46,148	40,168	162,300	153,761	155,037	147,033	157,003	153,647	152,345	161,799	1,412,029
TOTAL	9,224,418	8,962,125	9,340,309	8,728,686	9,465,386	9,231,465	9,733,095	9,708,227	9,894,881	9,058,951	8,976,555	9,582,781	111,906,879

ATTACHMENT 4
2009 ACTUAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	166,517	166,703	166,801	167,125	167,232	167,143	167,291	167,710	167,911	167,698	167,536	168,288	167,330
GENERAL SERVICE <50	16,318	16,315	16,320	16,297	16,256	16,236	16,173	16,163	16,176	16,182	16,498	16,624	16,297
SMALL COMMERCIAL	177	178	178	178	179	178	176	175	178	178	177	176	177
UNMETERED SCATTERED LOAD	2,889	2,893	2,892	2,889	2,888	2,887	2,887	2,886	2,889	2,892	2,893	2,896	2,890
GENERAL SERVICE 50-499	3,867	3,870	3,876	3,884	3,884	3,893	3,898	3,898	3,905	3,915	3,948	3,956	3,900
GENERAL SERVICE 500-4999	477	484	488	488	489	488	488	484	485	479	484	486	485
LARGE USE	10	10	10	10	10	10	10	10	10	10	10	10	10
STREETLIGHTING	48,550	48,568	48,568	48,573	48,631	48,677	48,733	48,776	48,806	48,821	48,815	48,819	48,695
kWh or kW Sales													
RESIDENTIAL	148,666,927	133,389,105	138,264,882	108,612,455	107,262,578	108,598,964	109,482,895	151,099,278	131,002,256	132,288,651	112,938,361	119,910,058	1,501,516,409
GENERAL SERVICE <50	59,636,249	58,229,249	60,231,608	50,125,947	52,539,386	51,484,545	52,635,371	58,981,871	49,060,078	51,743,257	51,337,351	56,296,877	652,301,791
SMALL COMMERCIAL	61,592	90,093	95,721	60,524	97,300	95,258	69,832	79,952	59,376	66,252	69,475	81,018	926,392
UNMETERED SCATTERED LOAD	654,798	957,793	1,017,634	643,440	1,034,416	1,012,703	742,394	849,990	631,239	704,334	738,605	861,322	9,848,668
GENERAL SERVICE 50-499	491,913	505,676	575,242	489,221	479,905	586,772	441,294	591,053	460,042	578,459	586,447	566,325	6,352,348
GENERAL SERVICE 500-4999	375,184	437,880	408,320	383,427	459,482	441,394	408,240	485,913	385,263	438,219	427,649	430,486	5,081,457
LARGE USE	147,935	142,117	163,846	138,706	145,335	155,960	145,306	170,311	139,482	149,153	154,609	148,168	1,800,927
STREETLIGHTING	8,984	8,604	10,793	7,874	10,131	9,535	8,133	10,235	7,699	9,192	9,870	9,457	110,507
Rates-Fixed Monthly($)													
RESIDENTIAL	11.59	11.59	11.59	11.59	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	
GENERAL SERVICE <50	38.98	38.98	38.98	38.98	39.44	39.44	39.44	39.44	39.44	39.44	39.44	39.44	
SMALL COMMERCIAL	10.44	10.44	10.44	10.44	10.56	10.56	10.56	10.56	10.56	10.56	10.56	10.56	
UNMETERED SCATTERED LOAD	10.44	10.44	10.44	10.44	10.56	10.56	10.56	10.56	10.56	10.56	10.56	10.56	
GENERAL SERVICE 50-499	68.21	68.21	68.21	68.21	69.01	69.01	69.01	69.01	69.01	69.01	69.01	69.01	
GENERAL SERVICE 500-4999	1501.66	1501.66	1501.66	1501.66	1,519.38	1,519.38	1,519.38	1,519.38	1,519.38	1,519.38	1,519.38	1,519.38	
LARGE USE	13527.08	13527.08	13527.08	13527.08	13,686.7	13,686.70	13,686.70	13,686.70	13,686.70	13,686.70	13,686.70	13,686.70	
STREETLIGHTING	1.31	1.31	1.31	1.31	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0117	0.0117	0.0117	0.0117	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	
GENERAL SERVICE <50	0.0114	0.0114	0.0114	0.0114	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
SMALL COMMERCIAL	0.0191	0.0191	0.0191	0.0191	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
UNMETERED SCATTERED LOAD	0.0191	0.0191	0.0191	0.0191	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
GENERAL SERVICE 50-499	4.1043	4.1043	4.1043	4.1043	4.1527	4.1527	4.1527	4.1527	4.1527	4.1527	4.1527	4.1527	
GENERAL SERVICE 500-4999	2.0482	2.0482	2.0482	2.0482	2.0724	2.0724	2.0724	2.0724	2.0724	2.0724	2.0724	2.0724	
LARGE USE	2.8529	2.8529	2.8529	2.8529	2.8866	2.8866	2.8866	2.8866	2.8866	2.8866	2.8866	2.8866	
STREETLIGHTING	10.0145	10.0145	10.0145	10.0145	10.1327	10.1327	10.1327	10.1327	10.1327	10.1327	10.1327	10.1327	
Revenue($)													
RESIDENTIAL	3,669,335	3,492,740	3,550,923	3,207,744	3,227,330	3,242,055	3,254,222	3,750,210	3,515,423	3,528,104	3,297,870	3,388,957	41,124,912
GENERAL SERVICE<50	1,315,929	1,299,772	1,322,794	1,206,693	1,245,340	1,232,420	1,243,170	1,315,760	1,202,172	1,233,266	1,241,061	1,303,065	15,161,441
SMALL COMMERCIAL	3,024	3,579	3,687	3,014	3,768	3,718	3,206	3,391	3,026	3,158	3,210	3,422	40,204
UNMETERED SCATTERED LOAD	42,668	48,497	49,629	42,451	50,462	50,032	44,815	46,881	42,691	44,133	44,805	47,205	554,269
GENERAL SERVICE 50-499	2,282,725	2,339,418	2,625,346	2,272,839	2,260,936	2,705,345	2,101,562	2,723,467	2,179,899	2,672,340	2,707,790	2,624,783	29,496,450
GENERAL SERVICE5 00-4999	1,484,744	1,623,669	1,569,132	1,518,146	1,695,208	1,656,203	1,587,495	1,742,385	1,535,317	1,635,947	1,621,639	1,630,559	19,300,443
LARGE USE	557,314	540,716	602,708	530,984	556,391	587,060	556,307	628,486	539,496	567,413	583,161	564,568	6,814,605
STREETLIGHTING	153,570	149,790	171,711	142,488	167,333	161,353	147,224	168,582	142,920	158,074	164,929	160,752	1,888,727
TOTAL	9,509,309	9,498,181	9,895,929	8,924,360	9,206,767	9,638,186	8,938,001	10,379,162	9,160,944	9,842,436	9,664,465	9,723,311	114,381,051

ATTACHMENT 5
2009 WEATHER NORMAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	166,517	166,703	166,801	167,125	167,232	167,143	167,291	167,710	167,911	167,698	167,536	168,288	167,330
GENERAL SERVICE <50	16,318	16,315	16,320	16,297	16,256	16,236	16,173	16,163	16,176	16,182	16,498	16,624	16,297
SMALL COMMERCIAL	177	178	178	178	179	178	176	175	178	178	177	176	177
UNMETERED SCATTERED LOAD	2,889	2,893	2,892	2,889	2,888	2,887	2,887	2,886	2,889	2,892	2,893	2,896	2,890
GENERAL SERVICE 50-499	3,867	3,870	3,876	3,884	3,884	3,893	3,898	3,898	3,905	3,915	3,948	3,956	3,900
GENERAL SERVICE 500-4999	477	484	488	488	489	488	488	484	485	479	484	486	485
LARGE USE	10	10	10	10	10	10	10	10	10	10	10	10	10
STREETLIGHTING	48,550	48,568	48,568	48,573	48,631	48,677	48,733	48,776	48,806	48,821	48,815	48,819	48,695
kWh or kW Sales													
RESIDENTIAL	147,733,098	132,777,646	137,633,030	108,111,424	106,581,903	107,918,813	108,980,920	150,411,822	130,409,469	131,634,772	112,450,175	119,401,329	1,494,044,402
GENERAL SERVICE <50	59,946,991	57,957,189	59,997,984	50,019,838	52,424,208	51,312,454	52,404,397	58,761,794	48,855,065	51,320,437	51,043,534	56,052,634	650,096,525
SMALL COMMERCIAL	57,047	83,463	88,684	56,068	91,771	88,187	64,670	74,063	54,864	61,382	64,434	75,068	859,702
UNMETERED SCATTERED LOAD	663,531	970,775	1,031,502	652,136	1,067,410	1,025,721	752,196	861,441	638,135	713,946	749,444	873,136	9,999,371
GENERAL SERVICE 50-499	499,623	513,602	584,258	496,890	487,427	595,970	448,211	600,317	467,253	587,526	595,639	575,202	6,451,919
GENERAL SERVICE 500-4999	377,717	440,836	411,077	386,016	462,584	444,374	410,996	489,193	387,864	441,177	430,536	433,393	5,115,763
LARGE USE	150,008	144,109	166,143	140,649	147,372	158,145	147,342	172,698	141,437	151,244	156,776	150,244	1,826,166
STREETLIGHTING	8,984	8,604	10,793	7,874	10,131	9,535	8,133	10,235	7,699	9,192	9,870	9,457	110,507
Rates-Fixed Monthly($)													
RESIDENTIAL	11.59	11.59	11.59	11.59	11.73	11.73	11.73	11.73	11.73	11.73	11.73	11.73	
GENERAL SERVICE <50	38.98	38.98	38.98	38.98	39.44	39.44	39.44	39.44	39.44	39.44	39.44	39.44	
SMALL COMMERCIAL	10.44	10.44	10.44	10.44	10.56	10.56	10.56	10.56	10.56	10.56	10.56	10.56	
UNMETERED SCATTERED LOAD	10.44	10.44	10.44	10.44	10.56	10.56	10.56	10.56	10.56	10.56	10.56	10.56	
GENERAL SERVICE 50-499	68.21	68.21	68.21	68.21	69.01	69.01	69.01	69.01	69.01	69.01	69.01	69.01	
GENERAL SERVICE 500-4999	1501.66	1501.66	1501.66	1501.66	1519.38	1519.38	1519.38	1519.38	1519.38	1519.38	1519.38	1519.38	
LARGE USE	13527.08	13527.08	13527.08	13527.08	13686.7	13686.7	13686.7	13686.7	13686.7	13686.7	13686.7	13686.7	
STREETLIGHTING	1.31	1.31	1.31	1.31	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0117	0.0117	0.0117	0.0117	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	
GENERAL SERVICE <50	0.0114	0.0114	0.0114	0.0114	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
SMALL COMMERCIAL	0.0191	0.0191	0.0191	0.0191	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
UNMETERED SCATTERED LOAD	0.0191	0.0191	0.0191	0.0191	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
GENERAL SERVICE 50-499	4.1043	4.1043	4.1043	4.1043	4.1527	4.1527	4.1527	4.1527	4.1527	4.1527	4.1527	4.1527	
GENERAL SERVICE 500-4999	2.0482	2.0482	2.0482	2.0482	2.0724	2.0724	2.0724	2.0724	2.0724	2.0724	2.0724	2.0724	
LARGEUSE	2.8529	2.8529	2.8529	2.8529	2.8866	2.8866	2.8866	2.8866	2.8866	2.8866	2.8866	2.8866	
STREETLIGHTING	10.0145	10.0145	10.0145	10.0145	10.1327	10.1327	10.1327	10.1327	10.1327	10.1327	10.1327	10.1327	
Revenue($)													
RESIDENTIAL	3,658,409	3,485,586	3,543,530	3,201,882	3,219,298	3,234,029	3,248,298	3,742,098	3,508,428	3,520,388	3,292,109	3,382,954	41,037,010
GENERAL SERVICE <50	1,319,471	1,296,671	1,320,131	1,205,483	1,244,015	1,230,441	1,240,514	1,313,229	1,199,815	1,228,403	1,237,682	1,300,256	15,136,110
SMALL COMMERCIAL	2,937	3,452	3,552	2,929	3,661	3,582	3,107	3,277	2,939	3,064	3,113	3,307	38,922
UNMETERED SCATTERED LOAD	42,835	48,745	49,894	42,617	51,099	50,283	45,004	47,102	42,824	44,319	45,014	47,433	557,168
GENERAL SERVICE 50-499	2,314,372	2,371,949	2,662,353	2,304,312	2,292,174	2,743,539	2,130,287	2,761,939	2,209,844	2,709,993	2,745,963	2,661,647	29,908,372
GENERAL SERVICE 500-4999	1,489,932	1,629,724	1,574,778	1,523,448	1,701,636	1,662,379	1,593,206	1,749,184	1,540,708	1,642,078	1,627,622	1,636,582	19,371,277
LARGE USE	563,229	546,398	609,259	536,530	562,270	593,369	562,185	635,376	545,138	573,447	589,416	570,562	6,887,179
STREETLIGHTING	153,570	149,790	171,711	142,488	167,333	161,353	147,224	168,582	142,920	158,074	164,929	160,752	1,888,727
TOTAL	9,544,755	9,532,316	9,935,208	8,959,690	9,241,486	9,678,975	8,969,826	10,420,788	9,192,615	9,879,767	9,705,848	9,763,493	114,824,766

ATTACHMENT 6
2010 ACTUAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	168,268	168,383	168,534	168,543	168,545	168,438	168,638	168,998	169,546	169,893	170,591	171,247	169,135
GENERAL SERVICE <50	16,575	16,578	16,610	16,597	16,593	16,645	16,674	16,682	16,699	16,765	16,821	16,836	16,673
SMALL COMMERCIAL	176	174	174	174	173	173	172	172	172	173	173	172	173
UNMETERED SCATTERED LOAD	2,906	2,907	2,907	2,909	2,911	2,913	2,913	2,915	2,919	2,921	2,927	2,934	2,915
GENERAL SERVICE5 0-499	3,941	3,954	3,961	3,956	3,965	3,972	3,976	3,985	3,983	4,004	4,025	4,026	3,979
GENERAL SERVICE 500-4999	485	484	485	488	488	486	486	483	485	485	481	480	485
LARGE USE	10	10	10	10	10	10	10	10	10	10	10	10	10
STREETLIGHTING	48,861	48,870	49,007	49,033	49,058	49,059	49,072	49,155	49,154	49,152	49,159	49,181	49,063
kWh or kW Sales													
RESIDENTIAL	135,667,861	138,149,436	126,681,416	104,706,103	120,858,728	111,220,698	176,620,569	185,963,414	150,948,452	126,366,301	92,447,513	119,950,485	1,589,580,977
GENERAL SERVICE <50	60,335,938	53,659,634	54,598,681	48,202,769	57,508,283	54,576,218	60,548,034	59,185,311	48,393,203	51,724,433	53,750,902	59,248,746	661,732,154
SMALL COMMERCIAL	95,311	78,866	83,533	83,008	103,080	81,052	75,777	70,249	49,304	110,198	79,044	78,649	988,070
UNMETERED SCATTERED LOAD	1,013,267	838,446	888,053	882,475	1,095,870	861,676	805,600	746,836	524,158	1,171,536	840,328	836,130	10,504,375
GENERALSERVICE50-499	522,532	465,280	434,519	572,887	598,751	470,137	583,308	499,199	588,221	477,166	570,718	521,169	6,303,886
GENERALSERVICE500-4999	407,588	417,729	352,158	443,956	478,527	392,516	472,105	442,404	446,877	380,159	450,471	400,401	5,084,891
LARGE USE	151,063	149,365	139,987	152,711	170,517	145,638	158,622	166,142	146,843	140,783	154,085	155,791	1,831,545
STREETLIGHTING	9,443	8,754	9,271	9,853	10,248	7,928	9,538	9,405	8,600	8,497	10,532	9,396	111,465
Rates-Fixed Monthly($)													
RESIDENTIAL	11.73	11.73	11.73	11.73	11.75	11.75	11.75	11.75	11.75	11.75	11.75	11.75	
GENERAL SERVICE <50	39.44	39.44	39.44	39.44	39.51	39.51	39.51	39.51	39.51	39.51	39.51	39.51	
SMALL COMMERCIAL	10.56	10.56	10.56	10.56	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	
UNMETERED SCATTERED LOAD	10.56	10.56	10.56	10.56	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	
GENERAL SERVICE 50-499	69.01	69.01	69.01	69.01	69.13	69.13	69.13	69.13	69.13	69.13	69.13	69.13	
GENERAL SERVICE 500-4999	1519.38	1519.38	1519.38	1519.38	1,522.11	1,522.11	1,522.11	1,522.11	1,522.11	1,522.11	1,522.11	1,522.11	
LARGE USE	13686.7	13686.7	13686.7	13686.7	13,711.34	13,711.34	13,711.34	13,711.34	13,711.34	13,711.34	13,711.34	13,711.34	
STREETLIGHTING	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	
GENERAL SERVICE <50	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
SMALL COMMERCIAL	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
UNMETERED SCATTERED LOAD	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
GENERAL SERVICE 50-499	4.1527	4.1527	4.1527	4.1527	4.1602	4.1602	4.1602	4.1602	4.1602	4.1602	4.1602	4.1602	
GENERAL SERVICE 500-4999	2.0724	2.0724	2.0724	2.0724	2.0761	2.0761	2.0761	2.0761	2.0761	2.0761	2.0761	2.0761	
LARGE USE	2.8866	2.8866	2.8866	2.8866	2.8918	2.8918	2.8918	2.8918	2.8918	2.8918	2.8918	2.8918	
STREETLIGHTING	10.1327	10.1327	10.1327	10.1327	10.1509	10.1509	10.1509	10.1509	10.1509	10.1509	10.1509	10.1509	
Revenue($)													
RESIDENTIAL	3,574,664	3,605,296	3,471,745	3,212,541	3,406,537	3,291,551	4,065,619	4,180,095	3,773,357	3,487,365	3,095,325	3,427,568	42,591,663
GENERAL SERVICE <50	1,347,581	1,270,922	1,282,983	1,208,918	1,316,935	1,285,270	1,355,092	1,339,737	1,216,299	1,257,216	1,282,733	1,346,551	15,510,238
SMALL COMMERCIAL	3,698	3,360	3,450	3,439	3,820	3,395	3,282	3,176	2,771	3,957	3,356	3,338	41,041
UNMETERED SCATTERED LOAD	50,243	46,880	47,837	47,751	51,949	47,450	46,368	45,255	40,999	53,515	47,186	47,179	572,611
GENERAL SERVICE 50-499	2,441,888	2,205,032	2,077,774	2,652,033	2,765,022	2,230,448	2,701,539	2,352,250	2,722,460	2,261,902	2,652,551	2,446,483	29,509,383
GENERAL SERVICE 500-4999	1,581,586	1,601,082	1,466,711	1,661,512	1,736,260	1,554,647	1,719,883	1,653,653	1,665,985	1,527,471	1,667,358	1,561,885	19,398,032
LARGE USE	572,924	568,025	540,953	577,681	630,214	558,269	595,815	617,562	561,753	544,229	582,697	587,631	6,937,754
STREETLIGHTING	160,666	153,700	159,116	165,054	169,276	145,724	162,089	160,844	152,671	151,625	172,292	160,784	1,913,841
TOTAL	9,733,252	9,454,297	9,050,568	9,528,930	10,080,012	9,116,754	10,649,688	10,352,572	10,136,296	9,287,281	9,503,497	9,581,418	116,474,563

ATTACHMENT 7
2010 WEATHER NORMAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	168,268	168,383	168,534	168,543	168,545	168,438	168,638	168,998	169,546	169,893	170,591	171,247	169,135
GENERALSERVICE<50	16,575	16,578	16,610	16,597	16,593	16,645	16,674	16,682	16,699	16,765	16,821	16,836	16,673
SMALL COMMERCIAL	176	174	174	174	173	173	172	172	172	173	173	172	173
UNMETERED SCATTERED LOAD	2,906	2,907	2,907	2,909	2,911	2,913	2,913	2,915	2,919	2,921	2,927	2,934	2,915
GENERAL SERVICE 50-499	3,941	3,954	3,961	3,956	3,965	3,972	3,976	3,985	3,983	4,004	4,025	4,026	3,979
GENERAL SERVICE 500-4999	485	484	485	488	488	486	486	483	485	485	481	480	485
LARGE USE	10	10	10	10	10	10	10	10	10	10	10	10	10
STREETLIGHTING	48,861	48,870	49,007	49,033	49,058	49,059	49,072	49,155	49,154	49,152	49,159	49,181	49,063
kWh or kW Sales													
RESIDENTIAL	129,079,287	122,391,817	117,567,842	97,218,006	112,497,286	103,153,593	164,146,111	172,799,186	140,473,998	117,380,878	85,832,225	111,465,561	1,474,005,792
GENERAL SERVICE <50	58,665,729	54,840,977	53,998,185	47,664,253	56,518,588	54,391,971	60,121,125	59,038,990	48,460,535	51,371,973	53,309,080	58,954,502	657,335,907
SMALL COMMERCIAL	84,817	72,958	75,651	75,189	91,036	72,866	70,774	63,653	47,171	99,610	71,475	71,183	896,383
UNMETERED SCATTERED LOAD	986,527	848,591	879,915	874,538	1,058,856	847,515	823,181	740,366	548,653	1,158,590	831,338	827,941	10,426,011
GENERAL SERVICE 50-499	513,989	457,672	427,414	563,521	588,961	462,450	573,771	491,037	578,603	469,364	561,387	512,647	6,200,816
GENERAL SERVICE 500-4999	405,620	415,712	350,457	441,812	476,216	390,620	469,825	440,267	444,719	378,323	448,296	398,467	5,060,333
LARGE USE	149,926	148,242	138,933	151,562	169,234	144,542	157,428	164,892	145,738	139,724	152,926	154,619	1,817,765
STREETLIGHTING	9,443	8,754	9,271	9,853	10,248	7,928	9,538	9,405	8,600	8,497	10,532	9,396	111,465
Rates-Fixed Monthly($)													
RESIDENTIAL	11.73	11.73	11.73	11.73	11.75	11.75	11.75	11.75	11.75	11.75	11.75	11.75	
GENERAL SERVICE <50	39.44	39.44	39.44	39.44	39.51	39.51	39.51	39.51	39.51	39.51	39.51	39.51	
SMALLCOMMERCIAL	10.56	10.56	10.56	10.56	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	
UNMETERED SCATTERED LOAD	10.56	10.56	10.56	10.56	10.58	10.58	10.58	10.58	10.58	10.58	10.58	10.58	
GENERAL SERVICE 50-499	69.01	69.01	69.01	69.01	69.13	69.13	69.13	69.13	69.13	69.13	69.13	69.13	
GENERAL SERVICE 5 00-4999	1519.38	1519.38	1519.38	1519.38	1522.11	1522.11	1522.11	1522.11	1522.11	1522.11	1522.11	1522.11	
LARGE USE	13686.7	13686.7	13686.7	13686.7	13711.34	13711.34	13711.34	13711.34	13711.34	13711.34	13711.34	13711.34	
STREETLIGHTING	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	
GENERAL SERVICE <50	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
SMALL COMMERCIAL	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
UNMETERED SCATTERED LOAD	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
GENERAL SERVICE 50-499	4.1527	4.1527	4.1527	4.1527	4.1602	4.1602	4.1602	4.1602	4.1602	4.1602	4.1602	4.1602	
GENERAL SERVICE 500-4999	2.0724	2.0724	2.0724	2.0724	2.0761	2.0761	2.0761	2.0761	2.0761	2.0761	2.0761	2.0761	
LARGE USE	2.8866	2.8866	2.8866	2.8866	2.8918	2.8918	2.8918	2.8918	2.8918	2.8918	2.8918	2.8918	
STREETLIGHTING	10.1327	10.1327	10.1327	10.1327	10.1509	10.1509	10.1509	10.1509	10.1509	10.1509	10.1509	10.1509	
Revenue($)													
RESIDENTIAL	3,496,919	3,419,356	3,364,204	3,124,182	3,307,872	3,196,359	3,918,421	4,024,757	3,649,759	3,381,337	3,017,265	3,327,446	41,227,876
GENERAL SERVICE <50	1,328,374	1,284,508	1,276,078	1,202,725	1,305,553	1,283,152	1,350,183	1,338,054	1,217,074	1,253,163	1,277,652	1,343,167	15,459,681
SMALL COMMERCIAL	3,496	3,246	3,298	3,289	3,587	3,237	3,186	3,048	2,730	3,753	3,210	3,194	39,271
UNMETERED SCATTERED LOAD	49,727	47,076	47,680	47,598	51,234	47,177	46,707	45,130	41,472	53,265	47,012	47,021	571,099
GENERAL SERVICE 50-499	2,406,410	2,173,441	2,048,271	2,613,136	2,724,295	2,198,470	2,661,862	2,318,295	2,682,449	2,229,445	2,613,730	2,411,033	29,080,837
GENERAL SERVICE 500-4999	1,577,506	1,596,901	1,463,186	1,657,068	1,731,462	1,550,712	1,715,149	1,649,217	1,661,505	1,523,659	1,662,841	1,557,870	19,347,077
LARGE USE	569,644	564,781	537,912	574,365	626,504	555,100	592,364	613,947	558,558	541,166	579,344	584,241	6,897,927
STREETLIGHTING	160,666	153,700	159,116	165,054	169,276	145,724	162,089	160,844	152,671	151,625	172,292	160,784	1,913,841
TOTAL	9,592,742	9,243,008	8,899,746	9,387,415	9,919,783	8,979,929	10,449,961	10,153,293	9,966,217	9,137,413	9,373,346	9,434,756	114,537,609

ATTACHMENT 8
2011 ACTUAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	171,567	171,749	171,970	172,133	172,326	172,421	172,433	172,615	172,788	172,975	173,227	173,444	172,471
GENERALSERVICE<50	16,856	16,838	16,889	16,888	16,855	16,846	16,827	16,846	16,955	17,074	17,104	17,163	16,928
SMALLCOMMERCIAL	173	172	173	173	173	173	173	172	171	171	169	168	172
UNMETEREDSCATTEREDLOAD	2,930	2,929	2,933	2,934	2,935	2,934	2,932	2,936	2,933	2,935	2,929	2,931	2,933
GENERALSERVICE50-499	4,028	4,030	4,037	4,054	4,069	4,072	4,111	4,103	4,031	3,962	3,937	3,945	4,032
GENERALSERVICE500-4999	480	479	482	478	479	483	480	478	476	465	463	463	476
LARGEUSE	11	11	11	11	11	11	11	11	11	11	11	11	11
STREETLIGHTING	49,215	49,218	49,219	49,218	49,218	49,232	49,234	49,241	49,233	49,262	49,288	49,279	49,238
kWh or kW Sales													
RESIDENTIAL	148,844,886	152,670,300	119,518,386	110,590,445	94,849,952	118,174,966	160,200,366	192,302,741	157,578,765	116,265,726	87,993,048	108,958,171	1,567,947,751
GENERALSERVICE<50	60,177,371	56,865,031	59,627,071	51,993,149	49,588,367	52,200,115	59,330,386	59,214,740	47,421,333	47,980,330	50,628,150	56,278,225	651,304,268
SMALLCOMMERCIAL	90,121	76,482	88,020	89,209	89,181	85,862	92,255	78,571	75,311	76,891	83,242	80,813	1,005,959
UNMETEREDSCATTEREDLOAD	958,094	813,098	935,756	948,402	948,103	912,813	980,786	835,309	800,643	817,445	884,968	859,140	10,694,557
GENERALSERVICE50-499	522,535	473,079	552,955	493,689	542,340	512,824	619,353	522,833	554,812	487,454	487,134	496,454	6,265,460
GENERALSERVICE500-4999	405,404	354,439	465,012	374,056	454,322	428,199	483,527	435,693	422,297	405,569	393,409	375,578	4,997,505
LARGEUSE	149,830	133,826	186,829	108,810	184,173	149,225	169,913	150,530	148,275	157,685	153,895	144,746	1,837,737
STREETLIGHTING	9,737	7,812	11,281	8,253	10,817	8,649	9,933	7,715	9,576	9,230	9,643	9,450	112,096
Rates-Fixed Monthly($)													
RESIDENTIAL	11.75	11.75	11.75	11.75	11.77	11.77	11.77	11.77	11.77	11.77	11.77	11.77	
GENERALSERVICE<50	39.51	39.51	39.51	39.51	39.58	39.58	39.58	39.58	39.58	39.58	39.58	39.58	
SMALLCOMMERCIAL	10.58	10.58	10.58	10.58	10.60	10.6	10.6	10.6	10.6	10.6	10.6	10.6	
UNMETEREDSCATTEREDLOAD	10.58	10.58	10.58	10.58	10.60	10.6	10.6	10.6	10.6	10.6	10.6	10.6	
GENERALSERVICE50-499	69.13	69.13	69.13	69.13	69.25	69.25	69.25	69.25	69.25	69.25	69.25	69.25	
GENERALSERVICE500-4999	1522.11	1522.11	1522.11	1522.11	1524.85	1524.85	1524.85	1524.85	1524.85	1524.85	1524.85	1524.85	
LARGEUSE	13711.34	13711.34	13711.34	13711.34	13,736.02	13736.02	13736.02	13736.02	13736.02	13736.02	13736.02	13736.02	
STREETLIGHTING	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	
GENERALSERVICE<50	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
SMALLCOMMERCIAL	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
UNMETEREDSCATTEREDLOAD	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
GENERALSERVICE50-499	4.1602	4.1602	4.1602	4.1602	4.1677	4.1677	4.1677	4.1677	4.1677	4.1677	4.1677	4.1677	
GENERALSERVICE500-4999	2.0761	2.0761	2.0761	2.0761	2.0798	2.0798	2.0798	2.0798	2.0798	2.0798	2.0798	2.0798	
LARGEUSE	2.8918	2.8918	2.8918	2.8918	2.8970	2.897	2.897	2.897	2.897	2.897	2.897	2.897	
STREETLIGHTING	10.1509	10.1509	10.1509	10.1509	10.1692	10.1692	10.1692	10.1692	10.1692	10.1692	10.1692	10.1692	
Revenue($)													
RESIDENTIAL	3,772,282	3,819,560	3,430,964	3,327,530	3,147,506	3,423,860	3,919,901	4,300,851	3,893,144	3,407,851	3,077,200	3,327,142	42,847,792
GENERALSERVICE<50	1,358,020	1,319,217	1,352,996	1,265,166	1,237,387	1,267,066	1,348,312	1,347,734	1,216,424	1,227,563	1,259,200	1,326,511	15,525,597
SMALLCOMMERCIAL	3,570	3,296	3,529	3,552	3,555	3,491	3,614	3,340	3,266	3,297	3,398	3,340	41,248
UNMETEREDSCATTEREDLOAD	49,491	46,682	49,091	49,346	49,409	48,718	50,008	47,243	46,542	46,888	48,127	47,650	579,195
GENERALSERVICE50-499	2,452,305	2,246,697	2,579,481	2,334,100	2,542,087	2,419,281	2,865,964	2,463,142	2,591,436	2,305,929	2,302,866	2,342,261	29,445,548
GENERALSERVICE500-4999	1,572,272	1,464,940	1,699,068	1,504,146	1,675,302	1,627,070	1,737,568	1,635,033	1,604,122	1,552,559	1,524,218	1,487,133	19,083,431
LARGEUSE	584,102	537,824	691,097	465,481	684,647	583,400	643,335	587,183	580,649	607,908	596,931	570,424	7,132,982
STREETLIGHTING	164,295	144,755	179,973	149,232	175,460	153,430	166,492	143,950	162,861	159,382	163,612	161,643	1,925,085
TOTAL	9,956,336	9,582,972	9,986,200	9,098,553	9,515,353	9,526,314	10,735,194	10,528,476	10,098,445	9,311,377	8,975,551	9,266,105	116,580,877

ATTACHMENT 9

2011 WEATHER NORMAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	171,567	171,749	171,970	172,133	172,326	172,421	172,433	172,615	172,788	172,975	173,227	173,444	172,471
GENERALSERVICE<50	16,856	16,838	16,889	16,888	16,855	16,846	16,827	16,846	16,955	17,074	17,104	17,163	16,928
SMALLCOMMERCIAL	173	172	173	173	173	173	173	172	171	171	169	168	172
UNMETEREDSCATTEREDLOAD	2,930	2,929	2,933	2,934	2,935	2,934	2,932	2,936	2,933	2,935	2,929	2,931	2,933
GENERALSERVICE50-499	4,028	4,030	4,037	4,054	4,069	4,072	4,111	4,103	4,031	3,962	3,937	3,945	4,032
GENERALSERVICE500-4999	480	479	482	478	479	483	480	478	476	465	463	463	476
LARGEUSE	11	11	11	11	11	11	11	11	11	11	11	11	11
STREETLIGHTING	49,215	49,218	49,219	49,218	49,218	49,232	49,234	49,241	49,233	49,262	49,288	49,279	49,238
kWh or kW Sales													
RESIDENTIAL	139,244,229	126,997,238	121,957,620	102,624,939	97,537,676	106,525,951	152,891,459	176,806,483	147,398,399	108,743,857	82,305,475	118,607,599	1,481,640,927
GENERALSERVICE<50	59,596,885	56,252,709	58,806,035	51,499,785	49,115,457	51,698,430	59,863,696	57,575,382	46,969,955	47,457,241	50,211,901	55,238,240	644,285,714
SMALLCOMMERCIAL	83,361	70,852	81,448	82,534	82,192	79,758	85,358	72,718	69,689	71,185	77,030	74,787	930,912
UNMETEREDSCATTEREDLOAD	969,593	824,092	947,335	959,975	955,990	927,687	992,812	845,800	810,569	827,965	895,949	868,077	10,825,844
GENERALSERVICE50-499	517,281	468,322	547,395	488,725	536,886	507,667	613,125	517,575	549,233	482,552	482,236	491,462	6,202,459
GENERALSERVICE500-4999	404,180	353,368	463,608	372,927	452,950	426,906	482,067	434,378	421,022	404,345	392,221	374,444	4,982,417
LARGEUSE	150,020	133,997	187,067	108,948	184,408	149,414	170,129	150,722	148,464	157,885	154,091	144,930	1,840,076
STREETLIGHTING	9,736	7,811	11,280	8,252	10,816	8,648	9,932	7,715	9,575	9,230	9,642	9,450	112,089
Rates-Fixed Monthly($)													
RESIDENTIAL	11.75	11.75	11.75	11.75	11.77	11.77	11.77	11.77	11.77	11.77	11.77	11.77	
GENERALSERVICE<50	39.51	39.51	39.51	39.51	39.58	39.58	39.58	39.58	39.58	39.58	39.58	39.58	
SMALLCOMMERCIAL	10.58	10.58	10.58	10.58	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	
UNMETEREDSCATTEREDLOAD	10.58	10.58	10.58	10.58	10.60	10.60	10.60	10.60	10.60	10.60	10.60	10.60	
GENERALSERVICE50-499	69.13	69.13	69.13	69.13	69.25	69.25	69.25	69.25	69.25	69.25	69.25	69.25	
GENERALSERVICE500-4999	1522.11	1522.11	1522.11	1522.11	1524.85	1524.85	1524.85	1524.85	1524.85	1524.85	1524.85	1524.85	
LARGEUSE	13711.34	13711.34	13711.34	13711.34	13736.02	13736.02	13736.02	13736.02	13736.02	13736.02	13736.02	13736.02	
STREETLIGHTING	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	

	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	
GENERALSERVICE<50	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	0.0115	
SMALLCOMMERCIAL	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
UNMETEREDSCATTEREDLOAD	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	0.0193	
GENERALSERVICE50-499	4.1602	4.1602	4.1602	4.1602	4.1677	4.1677	4.1677	4.1677	4.1677	4.1677	4.1677	4.1677	
GENERALSERVICE500-4999	2.0761	2.0761	2.0761	2.0761	2.0798	2.0798	2.0798	2.0798	2.0798	2.0798	2.0798	2.0798	
LARGEUSE	2.8918	2.8918	2.8918	2.8918	2.8970	2.8970	2.8970	2.8970	2.8970	2.8970	2.8970	2.8970	
STREETLIGHTING	10.1509	10.1509	10.1509	10.1509	10.1692	10.1692	10.1692	10.1692	10.1692	10.1692	10.1692	10.1692	
Revenue($)													
RESIDENTIAL	3,658,994	3,516,618	3,459,747	3,233,537	3,179,222	3,286,401	3,833,656	4,117,995	3,773,016	3,319,093	3,010,086	3,441,006	41,829,372
GENERALSERVICE<50	1,351,345	1,312,176	1,343,554	1,259,492	1,231,949	1,261,297	1,354,445	1,328,882	1,211,233	1,221,547	1,254,413	1,314,551	15,444,884
SMALLCOMMERCIAL	3,439	3,187	3,402	3,423	3,420	3,373	3,481	3,227	3,158	3,186	3,278	3,224	39,799
UNMETEREDSCATTEREDLOAD	49,713	46,894	49,315	49,569	49,562	49,005	50,240	47,446	46,734	47,091	48,339	47,822	581,729
GENERALSERVICE50-499	2,430,447	2,226,907	2,556,350	2,313,447	2,519,359	2,397,789	2,840,008	2,441,231	2,568,185	2,285,501	2,282,451	2,321,455	29,183,132
GENERALSERVICE500-4999	1,569,731	1,462,719	1,696,153	1,501,802	1,672,449	1,624,381	1,734,532	1,632,298	1,601,471	1,550,012	1,521,748	1,484,775	19,052,068
LARGEUSE	584,653	538,316	691,785	465,881	685,326	583,950	643,961	587,738	581,196	608,490	597,499	570,958	7,139,753
STREETLIGHTING	164,288	144,750	179,965	149,227	175,453	153,424	166,485	143,945	162,855	159,376	163,605	161,637	1,925,013
TOTAL	9,812,610	9,251,567	9,980,272	8,976,379	9,516,738	9,359,620	10,626,809	10,302,761	9,947,847	9,194,297	8,881,419	9,345,429	115,195,748

ATTACHMENT 10
2012 WEATHER NORMAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Customer/Connection Numbers													
RESIDENTIAL	173,795	173,996	174,197	174,398	174,599	174,801	175,002	175,204	175,407	175,609	175,812	175,874	174,891
GENERALSERVICE<50	17,085	17,101	17,118	17,134	17,151	17,168	17,184	17,201	17,218	17,234	17,251	17,412	17,188
SMALLCOMMERCIAL	168	168	168	168	168	168	168	168	168	168	168	168	168
UNMETEREDSCATTEREDLOAD	2,935	2,933	2,938	2,939	2,940	2,940	2,940	2,940	2,940	2,940	2,940	2,943	2,939
GENERALSERVICE50-499	3,945	3,945	3,945	3,945	3,945	3,945	3,945	3,945	3,945	3,945	3,948	3,948	3,946
GENERALSERVICE500-4999	464	464	464	464	464	464	464	464	464	464	464	464	464
LARGEUSE	10	10	10	10	10	10	9	9	9	9	9	9	10
STREETLIGHTING	49,282	49,323	49,364	49,405	49,447	49,488	49,529	49,570	49,612	49,653	49,694	49,736	49,509
kWh or kW Sales													
RESIDENTIAL	136,837,199	124,216,334	122,724,639	103,730,037	95,794,435	101,225,770	138,972,092	154,606,715	130,108,571	109,279,043	94,604,311	112,156,714	1,424,255,860
GENERALSERVICE<50	55,923,889	53,637,132	54,514,417	49,179,360	46,352,240	48,848,993	55,722,229	52,886,729	44,228,056	44,561,182	50,366,921	56,165,057	612,386,204
SMALLCOMMERCIAL	74,662	74,095	84,073	69,048	79,013	80,738	74,721	65,744	62,493	63,896	69,961	78,635	877,080
UNMETEREDSCATTEREDLOAD	868,414	867,751	955,539	802,713	927,969	936,185	815,923	782,615	811,360	731,495	855,396	937,883	10,293,244
GENERALSERVICE50-499	505,976	480,898	530,029	491,611	499,892	490,893	556,852	500,170	496,136	477,118	522,051	540,636	6,092,264
GENERALSERVICE500-4999	411,177	408,111	431,523	388,648	437,912	411,781	495,306	439,592	413,335	407,584	435,043	433,661	5,113,673
LARGEUSE	147,154	136,639	157,072	126,170	156,928	137,051	154,195	138,042	132,661	131,674	147,519	146,953	1,712,059
STREETLIGHTING	8,343	7,463	9,036	7,019	8,129	6,849	7,773	6,876	7,022	7,489	8,719	8,921	93,639
Rates-Fixed Monthly($)													
RESIDENTIAL	11.77	11.77	11.77	11.77	11.87	11.870	11.870	11.870	11.870	11.870	11.870	11.870	
GENERALSERVICE<50	39.58	39.58	39.58	39.58	39.93	39.930	39.930	39.930	39.930	39.930	39.930	39.930	
SMALLCOMMERCIAL	10.60	10.60	10.60	10.60	10.69	10.690	10.690	10.690	10.690	10.690	10.690	10.690	
UNMETEREDSCATTEREDLOAD	10.60	10.60	10.60	10.60	10.69	10.690	10.690	10.690	10.690	10.690	10.690	10.690	
GENERALSERVICE50-499	69.25	69.25	69.25	69.25	69.86	69.860	69.860	69.860	69.860	69.860	69.860	69.860	
GENERALSERVICE500-4999	1524.85	1524.85	1524.85	1524.85	1538.27	1538.270	1538.270	1538.270	1538.270	1538.270	1538.270	1538.270	
LARGEUSE	13736.02	13736.02	13736.02	13736.02	13856.90	13856.900	13856.900	13856.900	13856.900	13856.900	13856.900	13856.900	
STREETLIGHTING	1.33	1.33	1.33	1.33	1.34	1.340	1.340	1.340	1.340	1.340	1.340	1.340	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE/ TOTAL
Rates-Volumetric Charge($)													
RESIDENTIAL	0.0118	0.0118	0.0118	0.0118	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	
GENERALSERVICE<50	0.0115	0.0115	0.0115	0.0115	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	
SMALLCOMMERCIAL	0.0193	0.0193	0.0193	0.0193	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	
UNMETEREDSCATTEREDLOAD	0.0193	0.0193	0.0193	0.0193	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	
GENERALSERVICE50-499	4.1677	4.1677	4.1677	4.1677	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	
GENERALSERVICE500-4999	2.0798	2.0798	2.0798	2.0798	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	
LARGEUSE	2.8970	2.8970	2.8970	2.8970	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	
STREETLIGHTING	10.1692	10.1692	10.1692	10.1692	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	
Revenue($)													
RESIDENTIAL	3,660,250	3,513,685	3,498,447	3,276,677	3,212,445	3,279,470	3,731,046	3,919,496	3,630,368	3,384,900	3,212,676	3,422,285	41,741,744
GENERALSERVICE<50	1,319,332	1,293,691	1,304,437	1,243,742	1,222,527	1,252,154	1,332,550	1,300,324	1,200,551	1,205,083	1,273,098	1,346,775	15,294,264
SMALLCOMMERCIAL	3,222	3,211	3,403	3,113	3,337	3,370	3,253	3,078	3,015	3,042	3,160	3,329	38,533
UNMETEREDSCATTEREDLOAD	47,871	47,837	49,585	46,646	49,524	49,684	47,339	46,690	47,250	45,693	48,109	49,749	575,977
GENERALSERVICE50-499	2,381,945	2,277,432	2,482,192	2,322,077	2,377,345	2,339,510	2,616,827	2,378,514	2,361,553	2,281,594	2,470,720	2,548,858	28,838,569
GENERALSERVICE500-4999	1,562,697	1,556,319	1,605,011	1,515,841	1,632,541	1,577,715	1,752,959	1,636,066	1,580,975	1,568,908	1,626,520	1,623,621	19,239,175
LARGEUSE	563,665	533,205	592,397	502,876	597,192	539,099	575,347	528,139	512,415	509,529	555,837	554,182	6,563,885
STREETLIGHTING	150,386	141,494	157,539	137,092	149,656	136,571	146,107	136,968	138,513	143,360	156,032	158,168	1,751,886
TOTAL	9,689,370	9,366,874	9,693,012	9,048,064	9,244,568	9,177,575	10,205,428	9,949,274	9,474,640	9,142,108	9,346,153	9,706,968	114,044,034

ATTACHMENT 11
2013 WEATHER NORMAL DISTRIBUTION REVENUE

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE / TOTAL
Customer/Connection Numbers													
RESIDENTIAL	176,274	176,328	176,493	176,658	176,823	176,988	177,153	177,319	177,484	177,650	177,816	177,856	177,070
GENERALSERVICE<50	17,329	17,350	17,371	17,392	17,413	17,434	17,455	17,476	17,497	17,518	17,539	17,657	17,453
GENERALSERVICE<SMALLCOMMERCIAL	168	168	168	168	168	168	168	168	168	168	168	168	168
UNMETEREDSCATTEREDLOAD	2,935	2,933	2,938	2,939	2,940	2,940	2,940	2,940	2,940	2,940	2,940	2,940	2,939
GENERALSERVICE50-499	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,948	3,951	3,948
GENERALSERVICE500-4999	464	464	464	464	464	464	464	464	464	464	464	464	464
LARGEUSE	9	9	9	9	9	9	9	9	9	9	9	9	9
STREETLIGHTING	49,777	49,819	49,860	49,902	49,943	49,985	50,027	50,068	50,110	50,152	50,193	50,235	50,006
kWh or kW Sales													
RESIDENTIAL	135,638,115	121,304,452	121,066,519	103,110,115	94,987,560	100,585,223	139,438,470	154,397,727	132,477,028	109,874,204	95,898,761	115,079,302	1,423,857,475
GENERALSERVICE<50	55,308,756	52,254,026	53,683,491	48,838,684	45,922,543	48,501,821	55,798,371	52,632,543	44,889,377	44,707,691	51,103,883	57,662,410	611,303,594
GENERALSERVICE<SMALLCOMMERCIAL	74,586	73,005	83,667	69,334	79,215	81,064	75,530	66,100	64,116	64,845	71,667	81,380	884,507
UNMETEREDSCATTEREDLOAD	867,521	854,977	950,923	806,033	930,342	939,964	824,748	786,855	832,422	742,369	876,250	970,624	10,383,027
GENERALSERVICE50-499	504,941	473,158	526,871	493,121	500,617	492,362	562,407	502,377	508,656	483,787	534,444	559,282	6,142,022
GENERALSERVICE500-4999	410,314	401,617	428,961	389,808	438,548	413,015	500,196	441,504	423,596	413,209	445,210	448,358	5,154,338
LARGEUSE	147,848	135,437	157,234	127,511	158,195	138,308	156,680	139,600	137,052	134,406	151,931	153,063	1,737,267
STREETLIGHTING	5,735	4,202	4,810	3,348	3,763	2,492	2,615	2,248	3,323	4,541	6,231	6,582	49,889
Rates-Fixed Monthly($)*													
RESIDENTIAL	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	11.87	
GENERALSERVICE<50	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	
GENERALSERVICE<SMALLCOMMERCIAL	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	39.93	
UNMETEREDSCATTEREDLOAD	10.69	10.69	10.69	10.69	10.69	10.69	10.69	10.69	10.69	10.69	10.69	10.69	
GENERALSERVICE50-499	69.86	69.86	69.86	69.86	69.86	69.86	69.86	69.86	69.86	69.86	69.86	69.86	
GENERALSERVICE500-4999	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	1,538.27	
LARGEUSE	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	13,856.90	
STREETLIGHTING	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	AVERAGE / TOTAL
Rates-Volumetric Charge($)*													
RESIDENTIAL	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	0.0119	
GENERALSERVICE<50	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	
GENERALSERVICE<SMALLCOMMERCIAL	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	0.0116	
UNMETEREDSCATTEREDLOAD	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	0.0195	
GENERALSERVICE50-499	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	4.2044	
GENERALSERVICE500-4999	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	2.0981	
LARGEUSE	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	2.9225	
STREETLIGHTING	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	10.2587	
Revenue($)													
RESIDENTIAL	3,706,465	3,536,542	3,535,665	3,323,940	3,229,239	3,297,811	3,762,126	3,942,105	3,683,214	3,416,208	3,251,869	3,480,593	42,165,776
GENERALSERVICE<50	1,333,524	1,298,926	1,316,344	1,260,983	1,227,995	1,258,754	1,344,236	1,308,354	1,219,377	1,218,113	1,293,154	1,373,913	15,453,673
GENERALSERVICE<SMALLCOMMERCIAL	7,573	7,555	7,679	7,513	7,627	7,649	7,584	7,475	7,452	7,460	7,540	7,652	90,759
UNMETEREDSCATTEREDLOAD	48,292	48,026	49,950	47,136	49,570	49,758	47,511	46,772	47,661	45,905	48,515	50,356	579,452
GENERALSERVICE50-499	2,398,781	2,265,154	2,490,982	2,349,086	2,380,601	2,345,895	2,640,392	2,388,001	2,414,399	2,309,842	2,522,822	2,627,461	29,133,415
GENERALSERVICE500-4999	1,574,636	1,556,391	1,613,761	1,531,613	1,633,875	1,580,304	1,763,219	1,640,077	1,602,504	1,580,712	1,647,853	1,654,457	19,379,404
LARGEUSE	556,797	520,528	584,230	497,363	587,038	528,917	582,610	532,693	525,246	517,513	568,732	572,040	6,573,707
STREETLIGHTING	125,539	109,861	116,161	101,211	105,527	92,545	93,858	90,148	101,237	113,788	131,176	134,841	1,315,892
TOTAL	9,751,608	9,342,982	9,714,772	9,118,843	9,221,472	9,161,633	10,241,537	9,955,625	9,601,090	9,209,541	9,471,661	9,901,313	114,692,077

* 2013 Load at 2012 Rates

Other Revenue

Introduction

Other revenue relates to all utility revenues other than distribution and cost of power revenues.[1] Other revenues are also known as revenue offsets as they are used to offset the distribution revenue requirement. Enersource has classified other revenue into the following categories, which are the same categories used by Enersource in its 2008 cost of service application:

- Specific Service Charges;
- Late Payment Charges;
- Retailer Service Charges;
- Other Regulated Revenue; and
- Interest Revenue.

This exhibit will discuss the revenue associated with each category, or type, of other revenue from 2008 through the 2013 Test Year. A variance analysis by type of other revenue is also provided.

Other Revenue Categories and Revenues

Table 1 below provides a summary of other revenue from 2008 through the 2013 Test Year. The Board's Appendix 2-C, “Other Operating Revenue”, is also provided as Exhibit 3 Tab 3 Schedule 1 Appendix 2-C.

[1] No revenues or costs associated with conservation and demand management are included in the revenue requirement.

Table 1: Other Revenue Summary, 2008 to 2013 ($000s)

Other Revenue Category	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Specific Service Charges	1,282	1,330	1,311	1,283	1,347	1,330	1,335
Late Payment Charges	420	408	413	1,379	2,068	1,800	1,800
Retailer Service Charges	329	311	303	292	244	207	193
Other Regulated Revenues	1,260	1,189	1,124	1,608	1,212	1,464	1,452
Interest Revenue	2,049	1,957	284	187	735	377	50
TOTAL	5,340	5,195	3,434	4,751	5,605	5,178	4,830

Revenue offsets are deducted from the revenue requirement to derive the base revenue requirement. Each of the categories in Table 1 is described below.

Exhibit 3 Tab 3 Schedule 1 Appendices 1 and 2 provide detail supporting other revenues. Appendix 1 provides the number of transactions per year, from 2008 to 2013, for various types of other revenues including specific service charges, retailer charges and the SSS administration charge. Appendix 2 provides a detailed breakdown of the five other revenue categories shown in Table 1 from the 2008 Board-approved amount to the 2013 Test Year.

Specific Service Charges

Enersource charges user fees for certain services. Some of these services are provided at a customer's request, such as an account setup. Others result from Enersource's business operations, such as collection fees resulting from the non-payment of a customer bill. Enersource does not propose any changes to these specific service charges.

A number of Enersource's specific service charges, designed to recover the costs of providing these services, are described in the following sections.

Arrears Certificate

A charge is levied to research and issue a certificate of arrears per service address. This is typically provided to lawyers during a property purchase.

Collection Charge

A charge is levied to cover the additional costs for hand-delivering a disconnection notice to customers who have excessive payment arrears.

Reconnection Charge

A charge is levied to cover the additional costs of reconnecting a customer following a disconnection for arrears reasons. Different amounts are charged based on whether the reconnection is done at the pole or at the meter and if the reconnection is completed during regular hours or after regular hours.

Pole Rental

This is a specific charge for access to Enersource's power poles by other organizations, such as phone and cable companies.

Account Setup Charge

When a customer establishes a new account, a charge is applied to their first bill to cover the cost of setting up the new account.

Temporary Service Install and Remove Overhead – No Transformer

This is a charge for temporarily disconnecting then reconnecting electrical service so that construction or maintenance can be completed.

Credit Reference/Credit Check

Customers opening an account may qualify for a waiver on a security deposit based on a satisfactory credit check. This credit check is done at the customer's expense.

Returned Payment Charge

This charge is applied to a customer's account for each payment that cannot be processed.

Request for Other Billing Information

This charge is applied to a customer's account to provide additional information such as a letter of reference or income tax letter.

Standby Charge

Standby charges are rates paid by customers to receive power from the grid only at times when their distributed generation system is unavailable (during routine maintenance, unplanned outages, or supplemental power requirements).

Meter Test Charge

Customers who believe that their meter is reading incorrectly may request meter verification by Measurement Canada. This charge is applied to a customer's account if the Measurement Canada report indicates that the meter was reading correctly.

Interval Manual Charge

This charge is applied to a customer with an interval meter when the meter read cannot be completed over the phone line, which may not be in working order or is not properly installed. It is the customer's responsibility to maintain these phone lines.

MicroFIT Charge

Enersource currently applies a fixed monthly charge of $5.25 per month to the microFIT generator rate class for the administrative costs associated with supporting microFIT initiatives. The rate is an OEB-approved province-wide charge, which became effective September 21, 2009, and reflected the Board's determination of the province-wide average cost for all distributors. Enersource proposes to continue to charge the same $5.25 per month to the microFIT generator rate class to cover the administrative costs associated with supporting microFIT initiatives.

Late Payment Charges

Enersource proposes to continue to charge 1.5 percent per month (19.56 percent annually) for late payments. This would be applied to all accounts not paid by the due date. Bills are due and payable sixteen days from the mailing date plus grace days to allow for mailing and payment processing delays. A late payment charge ("LPC") is levied on any bill, excluding final bills, with no minimum set. The charge is based on the average daily balance outstanding including all charges, except deposits outstanding between the late payment due date and the LPC processing date.

Retailer Service Charges

Retail Service Charges include a standard charge, a monthly fixed charge, a monthly variable charge, a standard distributor consolidated billing charge, a request fee and a processing fee. Each is described in the following sections. In addition, further detail on Retailer Service Charges is provided at Exhibit 8 Tab 3 Schedule 1.

Standard Charge

This is a one-time charge, per retailer, to establish the service agreement between the distributor and the retailer.

Monthly Fixed Charge

This is a flat monthly charge billed to each active energy retailer account.

Monthly Variable Charge

This is a variable monthly charge to each active energy retailer for each of their customers.

Standard Distributor Consolidated Billing Charge

This is a variable monthly charge to each active energy retailer for each of their customers.

Request Fee

This is a fee for each customer request, and it is applied to the requesting party's account.

Processing Fee

A processing fee per each request is applied to the requesting party's account.

Other Regulated Revenue

Other Regulated Revenue includes Standard Supply Service ("SSS") administration charges, discounts earned on payments terms, leasing substation land, customer contributions, proceeds from sale of scrap, stale-dated cheque write-off, and other miscellaneous services revenue. Each of these is discussed in more detail below.

SSS Administration Charge

Enersource proposes to continue the charge of $0.25 per customer per month for all customers that receive their electricity commodity from the default, or standard supply service. Exhibit 3 Tab 3 Schedule 1 Appendix 3 provides detail on the revenues recovered through the application of the SSS Administration Charge from 2008 through 2013.

Discounts Earned on Payment Terms

Enersource earns a discount from select suppliers by paying invoices before a specified term date (for example 2%, 10 days, net 30). This amount of income reflects the discount earned from these suppliers.

Leasing Substation Land

Enersource leases two portions of substation land to Enbridge Gas Distribution Inc. for $2 per year.

Customer Contributions

Enersource receives customer contributions for various cost recovery or customer-specific projects. The amount proposed, and identified as "Miscellaneous Customer Contribution" on Exhibit 3 Tab 3 Schedule 1 Appendix 2, represents the difference between the fixed fee portion of customer contributions and the actual cost of providing the service related to the capital project.

Proceeds from Sale of Scrap

Enersource sells scrap metal left over after the completion of projects.

Stale-Dated Cheque Write-off

Cheques which have not been cashed by a customer after a two-year period are placed in income by Enersource. This is primarily related to final billing of customer accounts with a credit balance that cannot be located.

Capital Usage Charge

These are charges to affiliate companies for the use of assets owned by Enersource.

Proceeds from Sale of Fixed Assets

This includes revenues from the sale of retired assets such as vehicles and other equipment.

Interest Revenue

Interest revenue includes interest on cash and other short-term investments. Interest revenue associated with consumer deposits, and deferral and variance accounts are not included in interest revenue.

Other Revenue Variance Analysis

As mentioned earlier, Exhibit 3 Tab 3 Schedule 1 Appendix 2 provides details of other revenue from the OEB-approved amount for 2008 through to the 2013 Test Year. An explanation of the changes for each component of other revenue over this timeframe which exceeds the materiality threshold is described in detail below.

Specific Service Charges

There are no material variances in specific service charges over the period 2008 to 2013. The specific service charges forecast for the 2012 Bridge Year and 2013 Test Year were based on the trends from 2008 to 2011, changes in the number of customers, the number of new premises, and expectations in short term business conditions.

Late Payment Charges

Enersource has been experiencing large increases in LPCs since 2008.

Actual 2008 LPCs were $12 lower than the Board-approved 2008 amount of $420. LPCs then remained relatively flat from 2008 to 2009. However, there was a large increase of $966 in 2010, and a further increase of $688 in 2011. These material increases in 2010 and 2011 are a result of increased aging of Enersource's accounts receivable, and deterioration in collections due to economic conditions and the increase in energy costs. Bad debt expenses have,

correspondingly, increased significantly during this same period reflecting the same deterioration of the accounts receivable. Table 2 below highlights the bad debt expense and late payment revenue received or forecasted from 2008 to 2013.

Table 2: Late Payment Charges and Bad Debt Expense, 2008-2013 ($000s)

Description	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Late Payment Revenue	(420)	(408)	(413)	(1,379)	(2,068)	(1,800)	(1,800)
Bad Debt Expense	1,575	1,270	1,253	2,802	3,706	3,600	3,550
Net Impact	**1,155**	**862**	**840**	**1,423**	**1,638**	**1,800**	**1,750**

Enersource has taken a renewed focus on the collection of overdue accounts with the hiring of an Accounts Receivable Manager and selecting two new third-party collection agencies. Enersource anticipates that this will maintain LPCs to approximately $1,800 in both 2012 and 2013.

Retailer Service Charges

Retailer service charges in 2008 were $18 below the OEB-approved amount of $329. These charges have continued to decline between 2008 and 2011, at an approximate average of 9% annually. Enersource is forecasting that the declining trend from 2008 to 2011 will continue through 2012 and 2013. This is a direct result of the reduced number of customers contracted with retailers and the resultant reduction in the number of retail transactions. The reduction of retail customers in Enersource's territory has been approximately 4,500 customers between 2008 and 2011.

The OEB has established variance accounts (1518 Retail Cost Variance Retail - RCVA $_{Retail}$ and 1548 Retail Cost Variance STR – RCVA $_{STR}$) to record the difference between the amount billed and the incremental costs of providing retail services. For this Application, Enersource has assumed that the total retailer service revenue as described above is completely offset by operating costs related to servicing retailer operations and third-party costs from the operator of the retailer transaction hub. This is described in further detail at Exhibit 4 Tab 1 Schedule 13.

Other Regulated Revenue

There are no material variances in total other regulated revenue over the period 2008 to 2013. The charges forecast for the 2012 Bridge Year and 2013 Test Year continue this trend and are generally based on the average revenue experienced during the 2008 to 2011 period. Month-to-month variations are due to transaction timing and values of scrap sales, gain or loss on disposal of fixed assets, and the write-off of stale-dated cheques. Annual increases in the SSS administration charges are in line with the changes in the total number of customer accounts eligible for the charge because of total customer numbers increasing, combined with declines forecasted for customers contracted with retailers.

Interest Revenue

Interest revenue in 2008 was $92 below the OEB-approved amount of $2,049 due to differences in average cash balances and effective interest rates. Average cash balances have varied from an average of $62,244 in 2008, to $36,492, $23,259, and $65,683 in 2009, 2010 and 2011, respectively. Interest rates have also varied from 3% in 2008 to a low of under 1% in 2009 and 2010. Interest rates increased to approximately 1% in 2011.

The interest revenue forecast is based on an average cash balance and effective interest rates shown in Table 3 below. The interest rates are based on a consensus forecast of the largest five Canadian banks, where available.

Table 3: Interest Revenue, 2008 to 2013

Year	2008	2009	2010	2011	2012	2013
Average Cash Balance ($000s)	62,244	36,492	23,259	65,683	31,963	2,588
Interest Rate (%)	3.14	0.78	0.81	1.12	1.18	1.94
Interest Income ($000s)	1,957	284	187	735	377	50

Other Revenue / Revenue Offsets Volumes - Number of Transactions/Year

Other Revenue Types	US of A	Standard Amount ($ Rate)	Approved 2008	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Test Year 2013
Specific Service Charges									
Arrears Certificates	4235	15.00	400	331	221	251	384	267	267
Collection Charges	5330	9.00	16,500	19,287	15,864	9,607	16,427	18,667	18,667
Disconnect/reconnect at meter during regular hours	4235	20.00	1,284	1,014	720	282	989	755	755
Disconnect/reconnect at meter after regular hours	4235	32.00	180	142	101	137	424	203	203
Disconnect/reconnect at pole during regular hours	4235	185.00	3	2	2	2	2	2	2
Pole Rental	4210	22.35	20,716	23,250	23,439	24,019	24,204	23,714	23,803
Set up Charges - Residential	4235	20.00	17,500	17,100	17,985	20,718	20,520	18,852	18,852
Set up Charges - Commericial and Industrial	4235	30.00	3,700	3,615	3,802	3,440	3,338	3,099	3,099
Temporary service install & remove overhead - no trans	4235	400.00	150	122	109	105	95	100	100
Credit Check	4235	15.00	3,402	3,333	2,197	1,578	1,325	2,533	2,533
Return Payment Charge	4235	12.50	2,285	1,866	2,019	1,993	1,938	2,000	2,000
Request for other billing information(letter of reference)	4235	15.00	1,575	1,477	1,390	1,539	1,131	1,000	1,000
Standby charges	4235	200/500	24	24	24	24	24	24	24
Meter Test Charges	4235	10.00	15	8	5	-	-	-	-
Interval-Manual Charge	4235	40.00	1	95	455	160	(32)	100	100
MicroFit CustChg	4235	5.25	-	-	-	-	343	1,048	1,667
Sub-Total - Specific Service Charges			**67,735**	**71,666**	**68,333**	**63,855**	**71,112**	**72,364**	**73,072**
Retailer (RCVA) Charges									
Standard Charge(One time charge per retailer)	4082	100.00	1	1	3	-	2	-	-
Monthly Fixed Chrg (fixed charge per retailer)	4082	20.00	215	205	343	237	253	235	220
Monthly Variable Chrg (per customer per retailer)	4082	0.50	396,200	374,413	357,544	346,636	289,984	246,964	229,786
Std Distr Cons Bill Chrg (per customer per retailer)	4082	0.30	375,000	354,274	357,273	336,824	288,117	241,240	224,460
Request Fee (per request)	4084	0.25	26,400	24,763	21,829	24,731	11,737	10,800	10,000
Processing Fee (per request)	4084	0.50	14,800	14,055	8,647	13,877	8,372	7,800	7,200
Sub-Total - Retailer Charges			**812,616**	**767,711**	**745,639**	**722,305**	**598,465**	**507,039**	**471,666**
Other Regulated Revenue									
SSS Administration Charge	4080	0.25	1,908,000	1,854,694	1,906,045	2,007,318	2,092,233	2,130,520	2,143,856

Other Revenue / Revenue Offsets Details, 2008 to 2013 ($)

Other Revenue Types	US of A	Standard Amount (Rate)	Approved 2008	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Test Year 2013
Specific Service Charges									
Arrears Certificates	4235	15.00	6,000	4,963	3,313	3,758	5,764	4,000	4,000
Collection Charges	5330	9.00	148,500	173,587	142,779	86,461	147,847	168,000	168,000
Disconnect/reconnect at meter during regular hours	4235	20.00	25,680	20,281	14,397	5,640	19,780	15,100	15,100
Disconnect/reconnect at meter after regular hours	4235	32.00	5,760	4,549	3,229	4,384	13,568	6,500	6,500
Disconnect/reconnect at pole during regular hours	4235	185.00	555	438	311	370	370	400	400
Pole Rental	4210	22.35	463,003	519,647	523,868	536,835	540,953	530,000	532,000
Set up Charges - Residential	4235	20.00	350,000	341,994	359,694	414,368	410,406	377,044	377,000
Set up Charges - Commericial and Industrial	4235	30.00	111,000	108,461	114,074	103,189	100,147	92,956	93,000
Temporary service install & remove overhead - no tran	4235	400.00	60,000	48,770	43,600	42,000	37,982	40,000	40,000
Credit Check	4235	15.00	51,025	49,995	32,950	23,665	19,875	38,000	38,000
Return Payment Charge	4235	12.50	28,560	23,325	25,233	24,908	24,225	25,000	25,000
Request for other billing information(letter of reference)	4235	15.00	23,625	22,154	20,849	23,085	16,963	15,000	15,000
Standby charges	4235	200/500	8,400	8,400	8,400	8,400	8,400	8,400	8,400
Meter Test Charges	4235	10.00	150	80	50	-	-	-	-
Interval-Manual Charge	4235	40.00	40	3,800	18,200	6,407	(1,287)	4,000	4,000
MicroFit CustChg	4235	5.25	-				1,801	5,500	8,750
Sub-Total of Specific Service Charges			**1,282,298**	**1,330,444**	**1,310,947**	**1,283,470**	**1,346,794**	**1,329,900**	**1,335,150**
LPC- Res Non Elec Heat	4225		**420,000**	**407,623**	**412,941**	**1,379,315**	**2,067,728**	**1,800,000**	**1,800,000**
Retailer Service Charges									
Standard Charge(One time charge per retailer)	4082	100.00	100	100	300	-	200	-	-
Monthly Fixed Chrg (fixed charge per retailer)	4082	20.00	4,300	4,108	6,857	4,740	5,060	4,700	4,400
Monthly Variable Chrg (per customer per retailer)	4082	0.50	198,100	187,207	178,772	173,318	144,992	123,482	114,893
Std Distr Cons Bill Chrg (per customer per retailer)	4082	0.30	112,500	106,282	107,182	101,047	86,435	72,372	67,338
Request Fee (per request)	4084	0.25	6,600	6,191	5,457	6,183	2,934	2,700	2,500
Processing Fee (per request)	4084	0.50	7,400	7,027	4,324	6,939	4,186	3,900	3,600
Total			**329,000**	**310,915**	**302,891**	**292,226**	**243,807**	**207,154**	**192,731**
Other Regulated Revenue									
SSS Administration Charge	4080	0.25	477,000	463,673	476,511	501,830	523,058	532,630	535,964
Disc Earned on Payments	4390			20,532	20,570	-	5,619	11,000	11,000
Leasing - Substation Land	4390			3,200	4,400	6,000	4,000	4,000	4,000
Miscellaneous Revenue	4390			147,848	78,329	232,729	71,131	132,000	132,000
Misc. Customer Contribution	4390					33,580	25,321	29,000	29,000
Proceeds fr Sale of Scrap	4390			162,472	91,078	174,863	153,655	145,000	145,000
Staledated Cheq Write-Off	4235			27,081	-	82,231	47,295	36,500	33,250
Capital Usage Charge	4235		358,000	219,549	274,207	409,822	224,751	412,661	400,383
Disposals of Fixed Assets	4355			144,509	178,952	167,312	156,927	161,000	161,000
Other Regulated Revenue	4355		425,000						
Total			**1,260,000**	**1,188,865**	**1,124,047**	**1,608,365**	**1,211,757**	**1,463,791**	**1,451,597**
Interest Revenue	4405		**2,049,000**	**1,957,086**	**283,629**	**187,273**	**735,310**	**377,164**	**50,207**
Total Other Revenue			**5,340,298**	**5,194,933**	**3,434,456**	**4,750,650**	**5,605,397**	**5,178,009**	**4,829,685**

SSS Administration Charge Revenues, 2008 to 2013

Year	Average Number of SSS Customers			
	RES	GS<50	GS >50	TOTAL
2008 COS	139,902	16,028	3,229	159,159
2008	140,096	16,696	3,211	160,002
2009	140,848	16,879	3,178	160,905
2010	144,875	17,263	3,291	165,428
2011	151,973	17,961	3,391	173,324
2012	157,703	18,486	3,431	179,620
2013	161,170	18,827	3,487	183,485

Year	SSS Administration Charge Revenue * ($)			
	RES	GS<50	GS >50	TOTAL
2008 COS	420,000	47,500	9,500	477,000
2008	406,458	47,899	9,316	454,357
2009	417,597	49,491	9,423	467,088
2010	439,970	51,866	9,994	491,836
2011	459,101	53,714	10,243	512,815
2012	468,110	54,340	10,180	522,450
2013	478,117	47,505	10,342	525,622

* At the SSS charge of $0.25 per month

Appendix 2-C
Other Operating Revenue

USoA #	USoA Description	Approved 2008	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Test Year 2013
4080	SSS Administration Charge	$ 477,000	$ 463,673	$ 476,511	$ 501,830	$ 523,058	$ 532,630	$ 535,964
4082	Retail Services Revenues	$ 315,000	$ 297,697	$ 293,110	$ 279,105	$ 236,687	$ 200,554	$ 186,631
4084	Service Transaction Requests	$ 14,000	$ 13,218	$ 9,781	$ 13,121	$ 7,120	$ 6,600	$ 6,100
4210	Pole Rental	$ 463,003	$ 519,647	$ 523,868	$ 536,835	$ 540,953	$ 530,000	$ 532,000
4225	Late Payment Charges	$ 420,000	$ 407,623	$ 412,941	$ 1,379,315	$ 2,067,728	$ 1,800,000	$ 1,800,000
4235	Specific Service Charges	$ 670,795	$ 637,210	$ 644,300	$ 660,174	$ 657,994	$ 631,900	$ 635,150
4235	Miscellaneous Service Revenues	$ 358,000	$ 246,630	$ 274,207	$ 492,053	$ 272,046	$ 449,161	$ 433,633
4355	Gain on Disposition of Utility	$ 425,000	$ 144,509	$ 178,952	$ 167,312	$ 156,927	$ 161,000	$ 161,000
4390	Misc Non-Operating Income	$ -	$ 334,052	$ 194,378	$ 447,171	$ 259,727	$ 321,000	$ 321,000
4405	Investment Interest Income	$ 2,049,000	$ 1,957,086	$ 283,629	$ 187,273	$ 735,310	$ 377,164	$ 50,207
5330	Collection Charges	$ 148,500	$ 173,587	$ 142,779	$ 86,461	$ 147,847	$ 168,000	$ 168,000
Specific Service Charges		$ 1,177,295	$ 1,057,427	$ 1,061,286	$ 1,238,688	$ 1,077,887	$ 1,249,061	$ 1,236,783
Late Payment Charges		$ 420,000	$ 407,623	$ 412,941	$ 1,379,315	$ 2,067,728	$ 1,800,000	$ 1,800,000
Other Distribution Revenue		$ 1,269,003	$ 1,294,235	$ 1,303,270	$ 1,330,891	$ 1,307,819	$ 1,269,784	$ 1,260,695
Other Income and Expenses		$ 2,474,000	$ 2,435,647	$ 656,959	$ 801,756	$ 1,151,963	$ 859,164	$ 532,207
Total		$ 5,340,298	$ 5,194,933	$ 3,434,456	$ 4,750,650	$ 5,605,397	$ 5,178,009	$ 4,829,685

Description	Account(s)
Specific Service Charges:	4235,5330
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4405 - Interest and Dividend Income

		Actual 2008	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Test Year 2013
Short-term Investment Interest		$ 1,625,922	$ 45,757	$ 504	$ 11		
Bank Deposit Interest		$ 331,164	$ 237,872	$ 186,769	$ 735,299	$ 377,164	$ 50,207
Miscellaneous Interest Revenue							
Total	$ -	$ 1,957,086	$ 283,629	$ 187,273	$ 735,310	$ 377,164	$ 50,207

[1] List and specify any other interest revenue

Operating Costs Manager's Summary

Enersource's operating, maintenance, and administration ("operating" or "OM&A") costs from 2008 to 2013 are provided in Table 1 below. Table 1 presents the operating costs for summarized business units and other key drivers.

The summarized business units have experienced cost pressures since 2008 due to rising salaries and benefits, and maintaining the expected level of service to Enersource's customers. In other words, it represents a sub-total of operating costs for Enersource's "business as usual" scenario.

The other key drivers are items that were largely unforeseen during the 2008 cost of service rate application, EB-2007-0706. These are initiatives due to new or changing regulatory and business needs. The increased OM&A costs for these business units and other key drivers are described below.

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.

Table 2: Variance of Total Operating Costs, 2008 vs. 2013

Source of Increase	Amount ($000s)	Percentage Increase
Increase Due to Normal Business Unit Activities	11,625	60%
Increase Due to Other Key Drivers	7,821	40%
Total Operating Cost Increase 2008 to 2013	19,446	100%

The increase in costs for normal business unit activities represents 60% of the operating cost increase since 2008. Other key drivers explain 40% of the operating cost increase.

Excluding the operating expenses due to other key drivers (IFRS overhead burdens, bad debts, asset management plan ("AMP") initiative, one-time costs and the new administration office), total operating expenses in 2013 will be $51,704, representing a 4.4% average annual compound growth rate.

Various business units or Company initiatives are listed on Table 1. Each of these is discussed in detail in Schedules 2 to 13 of Exhibit 4 Tab 1 as listed in Table 3 below:

Table 3: Discussions on Operating Costs at Exhibit 4 Tab 1

Business Unit or Company Initiative	Schedule
Health, Safety and Security ("HS&S")	Schedule 2
Customer Care ("CC") (incl. Bad Debt Expense)	Schedule 3
Engineering and Operations ("E&O")	Schedule 4
Asset Management Plan ("AMP") Initiative	Schedule 5
Metering	Schedule 6
Enersource Executive and Administration ("E&A")	Schedule 7
Shared Services/Corporate Allocation	Schedule 8
Information Solutions and Technology Services ("ISTS")	Schedule 9
Regulatory Affairs ("RA")	Schedule 10
Facilities Management Services ("FMS")	Schedule 11
New Administration Office	Schedule 12
IFRS Overhead Burdens	Schedules 1, 4, 11
One Time Costs	Schedules 1, 6, 10
Other Expenses	Schedule 13

The remainder of this exhibit summarizes some of the key drivers of the operating costs in the 2013 Test Year.

Pension and Other Benefits Costs

Overall benefits costs increase from $5,320 in 2008 Rates to $9,248 in 2013. The benefits costs increase is largely due to higher pension-related (OMERS) contributions. Table 4 shows the pension contribution rates since 2008, which have risen by approximately one-third since 2008. Further discussion on benefits and compensation costs is provided at Exhibit 4 Tab 3 Schedule 1.

Table 4: Enersource Pension Contribution Rates for Members with a Normal Retirement age of 65

Limit	2008	2009	2010	2011	2012
Up to CPP earnings limit	6.5%	6.3%	6.4%	7.4%	8.3%
Above CPP earnings limit	9.7%	9.5%	9.7%	10.7%	12.8%

Aging System Infrastructure

Operating costs have risen in the E&O division due to the growing challenge to maintain and replace the aging infrastructure of the Enersource distribution system. For example, overtime and contract costs in E&O have increased $2,087 since 2008. This increase is associated with 24/7 trouble trucks and other labour costs that must respond to outages of the system, and perform the necessary repairs to maintain reliability.

Reliability statistics provided in Tables 6.1 and 6.2 of the AMP found at Exhibit 2 Tab 2 Schedule 2 Appendix 1 highlight the growing problems associated with an aging system. The number of outages per year has risen from 384 to 1028, or 167%, from 2008 to 2011. The number of customer minutes of interruptions has risen from 3.6 million to 10.3 million from 2008 to 2011. This represents an increase of 6.7 million minutes, or 186%. Defective equipment has caused approximately half of the incremental interruptions.

In addition, the fact of aging infrastructure has required the investment of significant resources to monitor and manage the performance and replacement of distribution system assets. This is reflected in the additional ISTS staff and OM&A related to the AMP initiative, and internally-driven capital investments described in Exhibit 2 Tab 3 Schedule 2 Appendix 1.

IFRS Overhead Burdens on OM&A Costs

As shown in Table 1, the transition to IFRS has resulted in incremental operating costs, due to overhead burdens. IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP, are not allowed under IFRS. This change resulted in a decrease of capital expenditures of $2,525 compared to CGAAP and an offsetting increase in OM&A for the same amount for 2011. This is forecast to rise to $3,022 in $2012, and $2,774 in the 2013 Test Year. These are discussed in further detail at Exhibit 4 Tab 1, in Schedules 4 and 11, respectively.

Table 5 below provides a breakout of the overhead burdens identified in Table 1.

Table 5: Total Overhead Burden Allocated to OM&A ($000s)

Allocation Specifics	2011 Actual	2012 Bridge	2013 Test
Labour and Material Burden - E&O	2,042	2,520	2,261
Fleet Burden - Facilities Management	483	502	513
Total Overhead Burden	2,525	3,022	2,774

Bad Debt Expenses

Since 2008, Enersource has experienced a significant increase in the amount and number of accounts deemed to be uncollectable. The net impact on the 2008 revenue requirement was expected to be $1,155. In the 2013 Test Year, the net impact of bad debts on Enersource's revenue requirement is expected to increase to $1,750. This is discussed in detail at Exhibit 4 Tab 1 Schedule 3.

One-Time Costs

Enersource has included certain costs for inclusion in operating costs and rates for the next four years to recover expenses related to one-time activities (referred to as "one-time costs"). These one-time costs are the regulatory costs for this Application, and costs associated with meeting Measurement Canada SE-04 specifications.

Enersource anticipates that it will incur a significant amount of expense relating to this Application. These additional regulatory costs total $650, as explained in Table 4 of Exhibit 4 Tab 1 Schedule 10. Enersource believes these costs should be recovered and amortized over four years to coincide with the expected cost of service period plus IRM term.

Measurement Canada requires that all newly-installed suite meters be inspected and certified to Measurement Canada's SE-04 specification within one year after installation. To comply with this requirement, Enersource expects to incur one-time costs totalling $352 as shown at Table 2 of Exhibit 4 Tab 1 Schedule 6. Further explanation of these costs is also provided in Schedule 6. Enersource believes these costs should also be recovered and amortized over four years to coincide with the expected cost of service period plus IRM term.

Employee Headcount and Type of Employee

The number of Enersource utility employees will rise from 318, the Board-approved level in 2008, to 339 in 2013. This is summarized in Table 6 below. Further detail on Enersource staffing and compensation is discussed at Exhibit 4 Tab 3 Schedule 1.

Table 6: Enersource Employee Count by Year

Business Unit/Initiative	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
HS&S	0	0	0	3	3	3
Customer Care	62	60	59	57	59	59
E&O	171	170	169	167	168	169
Asset Management Plan Initiative	0	0	0	0	1	5
Metering	22	23	24	26	24	24
Enersource E&A	10	11	9	9	8	8
ISTS	39	38	41	43	46	49
Regulatory Affairs	0	0	2	3	3	3
Facilities Management	14	17	17	16	16	16
New Administration Office	0	0	0	0	3	3
Total Enersource Headcount	318	319	321	324	331	339

Table 7 below provides the breakdown by type of employee for 2008 through 2013.

Table 7: Enersource Employee Type by Year

Business Unit	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside	84	81	81	82	83	84
Outside	143	144	143	141	142	143
Non- Union	91	94	97	101	106	112
Total	**318**	**319**	**321**	**324**	**331**	**339**

Operating Cost OEB Appendices

The following OEB Appendices to Exhibit 4 are provided where indicated:

- Accounts for OM&A Analysis (Tab 1 Schedule 1 Appendix 2-D)
- Summary of OM&A Expenses (Tab 1 Schedule 1 Appendix 2-E);
- Detailed, Account by Account, OM&A Expense Table (Tab 1 Schedule 1 Appendix 2-F);
- OM&A Cost Driver Table (Tab 1 Schedule 1 Appendix 2-G);
- Regulatory Cost Schedule (Tab 1 Schedule 1 Appendix 2-H);
- OM&A Cost per Customer and per Full Time Equivalent (Tab 1 Schedule 1 Appendix 2-I);
- OM&A Variance Analysis (Tab 2 Schedule 1 Appendix 2-J);
- Employee Costs (Tab 3 Schedule 1 Appendix 2-K)
- Shared Services/Corporate Cost Allocation (Tab 4 Schedule 1 Appendix 2-L).

OM&A Cost per Customer and per Full Time Equivalent (Appendix 2-I)

The OM&A Cost per Customer in 2013 is $306.74. This compares to $221.84, as approved by the Board for 2008.

The OM&A cost per Full Time Equivalent in 2013 is $156,264. This compares to $113,188, as approved by the Board for 2008. (These costs are provided in dollars and not thousands of dollars.)

OM&A Shared Services/Corporate Cost Allocation (Appendix 2-L)

A summary of the total Enersource Corporation ("EC") operating costs allocated to Enersource (the regulated utility) is shown in Table 8 below, and is discussed at Exhibit 4 Tab 1 Schedule 8.

Table 8: EC Costs allocated to Enersource as per Appendix 2-L ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Total EC Operating Costs	10,154	9,977	9,689	10,233	10,006	10,849	11,644
Allocated to Enersource (in Table 1)	8,546	8,358	8,842	9,721	9,506	10,131	10,874

Health Safety and Security Operating Costs

Enersource has one operating business unit that is responsible for health, safety and security ("HS&S") and the associated expenses.

The HS&S division was transferred from Enersource Corporation ("EC") in 2011 to better align safety, security, training and operational processes. The main focus of the HS&S division is to take a leadership role in the design, implementation and maintenance of all safety systems and programs for all Enersource employees.

The majority of costs, excluding salaries and benefits, in the HS&S division relate to training, benchmarking and security expenses. For example, HS&S provides a minimum of 40 hours of safety training annually per journeyman[1] tradesperson. Apprentices seeking their journeyman certificate receive 80 hours annually of trade-specific training over a four-year period. Apprenticeship training costs have been increasing due to the number of new apprentices required to replace the increasing number of retirees, as well as apprentices who are leaving the company after successful completion of their journeyman certificate.

HS&S also conducts benchmarking audits to ensure Enersource's health and safety programs are in compliance with the governing provincial and federal legislation, including the Electrical Utility Safety Rules and Guidelines for the province of Ontario.

[1] The masculine use of the tradename is born of convention. Enersource is proud to be an equal opportunity employer.

Over the next two years, the HS&S department will be implementing a managed health and safety system that aligns with *Occupational Health and Safety Assessment Series 18001* ("OHSAS 18001").

To assist in the move towards certification of a managed health and safety system, HS&S has installed a new health, safety and environment software system in 2011 that will collect, track and report on safety data from all business units. The successful implementation of the software will help identify, analyze and mitigate safety hazards for customers, employees and the general public, thereby increasing Enersource's safety performance, a key component of the organization's strategic goals and objectives.

The HS&S department is also responsible for ensuring that public safety programs and information are available for customers and the public. A major component of this ongoing effort is an interactive safety portal on the Enersource web page that focuses on electrical safety for children.

Finally, the cost of providing 24/7 security to the existing 3240 Mavis Road location has increased since 2008.

HS&S Operating Costs

In 2012 and 2013, the HS&S division will focus on implementing a managed health and safety system to meet the safety objectives within the corporate strategic plan.

HS&S operating costs and recoveries are shown below in Table 1.

Table 1: Operating Costs by Type and by Year: HS&S ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$ -	$ -	$ -	$ -	$ 304	$ 313	$ 324
Benefits	-	-	-	-	123	137	150
Safety Equipment & Supplies	-	-	-	-	148	158	161
Benchmarking and Program Costs	-	-	-	-	35	83	86
Security	-	-	-	-	220	316	323
HS&S services provided to affiliates	-	-	-	-	(154)	(186)	(198)
EC – Shared Services Allocation	$ 654	$ 597	$ 606	$ 580	-	-	-
Total Costs	**$ 654**	**$ 597**	**$ 606**	**$ 580**	**$ 676**	**$ 821**	**$ 846**

HS&S costs have increased overall from 2008 rates to 2013 Test Year by $192, or 29%. The increase is primarily due to an increase in salaries and benefits combined with increases in safety equipment & supplies and security costs.

The increase in employee benefits is mainly due to pension related costs (OMERS).

Services provided to Affiliates

The operating costs associated with HS&S were included in the management fee allocation from EC to Enersource prior to 2011. Beginning in 2011, the operating costs were charged to Enersource then allocated to the affiliates based on the number of headcount in each affiliate.

HS&S expenses are incurred by Enersource and are charged to all other active companies within the Enersource family of companies. This treatment is

consistent with the Board's Affiliate Relationships Code ("ARC") and is reflected in the service agreement between Enersource and its affiliates.

Enersource forecasts that it will recover $198,000 in the 2013 Test Year through the HS&S recovery rate. The corresponding amount for the 2012 Bridge Year is $186,000 (as indicated in Table 1 above).

Table 2: Employee Count by Year and Type: Health, Safety and Security

Employee Type	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Non-Union	-	-	-	3	3	3
HS&S Headcount	-	-	-	3	3	3

The HS&S division was part of Enersource Corporation from 2008 through 2010. The HS&S division transferred to Enersource in 2011. From 2008 through 2011, the HS&S division was comprised of two non-union employees.

Overall, Enersource HS&S has had a net increase of one position since 2008, with the addition of a Manager of Health and Safety in late 2010. Enersource converted a Vice President, Safety and Security position to a Director level position and converted a Manager Work Methods and Training position to a non-union Supervisor of Work Methods and Training in late 2009 with a primary focus on the apprenticeship program. Enersource's HS&S business unit does not anticipate the need for any new resources in the 2012 Bridge or 2013 Test Year.

In summary, the increase in HS&S costs is attributable to:

- Increase in overall staff levels (one new manager position);
- Increased average compensation levels;

- Significant increase in employee benefits (mainly due to OMERS pension-related costs);
- Increase in safety equipment and supplies;
- Increase in benchmarking and program delivery expenses; and
- Increased security costs.

Customer Care Operating Costs

Enersource's Customer Care division consists of the Customer Service, Meter Data, Billing, Settlements and Collections departments. These various units are responsible for the "Meter-to-Cash" processes which involve the meter reading, billing, collections, and cash payment processes. Each of their respective responsibilities is briefly described below. This is followed by individual sections with further detail on the operating costs within each unit.

Billing - transforms metering data, either manually or electronically, into customer invoices.

Customer Service - answers and responds to customer requests regarding meter reading and billing issues such as set-up of new service accounts, change of address, final bills, initial bills, meter reading clarification, bill calculation clarification, rate changes, and power outages.

Collections – collects all unpaid bills and invoices based on Enersource's objectives and ability to manage overdue accounts. The Collections business unit manages all third-party collection agencies relationships.

Settlements - is responsible for verifying and processing wholesale metering data, including the verification and payments to Hydro One Networks Inc. ("Hydro One") and the Independent Electricity System Operator ("IESO"). Settlements also completes the billing of Metered Inside Settlement Timeframe ("MIST") customers in addition to providing pricing and Net System Load Shape ("NSLS") (information required to correctly bill and settle other standard system supply ("SSS") customers). This business unit also manages billing and settlement of all embedded generators, as well as wholesale metering compliance.

Meter Data - ensures the accurate and timely processing of all meter data. This business unit manages retailer relationships and ensures the accuracy of retailer-related transactions, while monitoring retailers for mandated service level agreements and prudential obligations. The other functions within this business unit include bill delivery, hub services, and abloy lock installations.

Meter reading, bill printing, and call centre services are provided under contract with third-party providers.

Billing

Billing is responsible for the production of over 1,300,000 customer electricity bills annually. Enersource bills its residential customers bi-monthly and its general service customers monthly. Enersource offers a variety of billing and payment options, including the budget billing program (that permits customers to pay equal amounts each month) and an electronic funds transfer or credit card option. The main areas of responsibility for this business unit include:

- addressing billing system “edits” (“edits” are action items identified as part of the verification and reporting process);
- administering budget billing plans for over 25,000 customer accounts and processing over 700 new applications annually;
- administering automatic payments for over 34,000 customer accounts, and processing approximately 5,000 new applications annually;
- testing semi-annual commodity rate changes, and other regulatory or program changes to the billing system software;
- administering rate reclassifications and the Ontario Clean Energy Benefit (“OCEB”) credits;

- administering the billing verification system to ensure billing accuracy; and,
- administering the billing of over 50 microFIT and FIT customer accounts, with over 250 pending applications.

Billing is also responsible for investigating escalated customer complaints. In this capacity, Billing works closely with Information Solutions and Technology Services ("ISTS") to diagnose, recommend, promote, and test improvements to the customer information system ("CIS") also known as Customer Care and Billing (CC&B").

Customer Service

Enersource provides its customers a number of contact methods, including:

- walk-in lobby;
- telephone – in person or by interactive voice response ("IVR") technology;
- letter;
- fax;
- email; and
- internet.

Telephone access for power outages and emergencies is provided 24 hours a day, seven days a week. Non-emergency contacts are managed during core business hours, 8:30 a.m. to 4:30 p.m. Monday to Friday. In addition to back office functions, the contact call centre responds to more than 145,000 calls a year. During the 2013 Test Year, Enersource forecasts that it will handle 171,000 calls, an increase of about 32% over the 130,000 call volumes experienced in 2008 and 18% over 2011.

Enersource's contact call centre manages three key types of customer calls:

- outages and emergencies;
- bill and account inquiries; and
- service requests.

In 2011, these categories made up 1%, 96%, and 3% of the annual calls, respectively. The balance of the calls received is classified as "other" and include topics such as electricity pricing and market changes, energy efficiency, electrical safety, and damage claims.

An outage call can relate to either a planned or unplanned power outage. Enersource receives emergency calls from emergency service agencies and personnel (e.g., fire, police) and the general public. These calls typically concern damage caused to field-based equipment or notification of unsafe conditions.

Bill and account inquiry calls concern:

- collections activity including negotiating payment arrangements, payment confirmation, and responding to customer calls during the disconnection and reconnection process;
- questions regarding high bills, account balances, bill format, rates and bill charges (including commodity pricing, HST, and debt retirement charges);
- security deposits, rate changes, rate classifications;
- exemptions and refunds;
- usage and meter readings;
- damaged or malfunctioning meters;

- payment options, payment confirmation, and late payment charges;
- changes to customer account details;
- move-in and move-out calls triggered by a change of property ownership or tenancy (move-in calls require that an account be opened; move-out calls require a final bill that must be supported by a final meter reading);
- requests for information;
- requests for a letter of reference;
- budget billing and electronic funds transfer; and
- eBilling.

Service request calls include:

- customer requests for new electricity service or an upgrade to existing service; and
- third party (such as contractors) requests to provide engineering investigations to enable the connection of a new service or service upgrade.

Call volumes can change quickly and dramatically due to a variety of reasons, many of which are beyond Enersource's control. For example, storms and media coverage about electricity rates or electricity-related discussions in the Legislature can result in higher than normal high call volumes at unexpected times.

In addition to responding to customer calls, the contact call centre also responds to inquiries received via the other contact methods previously identified. Enersource has implemented a number of initiatives to improve contact handling

services for customers and to reduce customer contact handling costs. Enersource offers a number of self-serve features on the IVR. The Enersource website provides self-service options such as registration for a pre-authorized payment option, or registration for "My Account" service, all of which are accessible at the customer's convenience. "My Account" now includes options to view and pay bills, and view historical data and time-of-use ("TOU") consumption. In addition, the contact centre distributes brochures and other information (such as smart meter and TOU brochures, bill copies, and summaries for tax purposes, welcome packages, and Enersource's Conditions of Service.

Enersource prides itself with its high standards of customer service. Enersource closely tracks and monitors customer service quality indicators, that correspond to the Board's electricity service quality requirements ("ESQRs"). The results of these indicators for 2009 to 2011 are provided at Exhibit 2 Tab 3 Schedule 1 Appendix 1. Table 1 of this schedule shows that Enersource has consistently exceeded the Board's target by answering over 80% of all telephone calls within 30 seconds. Enersource continuously tries to improve on this performance to ensure customers receive the best possible service.

Collections

Enersource collects funds associated with electricity revenues for both active and final-billed accounts. This work includes:

- issuing collection letters and notices;
- negotiating payment arrangements;
- issuing payment confirmation letters;
- providing information for power of sales, foreclosures, bankruptcies, debt reviews, and consumer proposals and receiverships;

- issuing disconnection orders and scheduling disconnections; and
- managing third party collection agencies.

The aging and amounts of accounts in arrears have grown significantly since 2008. This has led to increased collections activities and costs. This is discussed more fully below.

Settlements

Enersource ensures the integrity of financial transactions between Enersource and the IESO, and between Enersource and its customers, by providing the appropriate level of due diligence to ensure that billing and payment transactions are reconciled appropriately for parties involved, and to ensure that affected customers receive timely and accurate bills.

Enersource's Settlements business unit responsibilities include:

- Reconciling purchases of energy from the IESO;
- Applying retail transmission service tariffs;
- Settlement and billing of embedded generators;
- Updating data and the overall management of all wholesale metering points;
- Implementing commodity and other charges, including appropriate distribution rates;
- Settlements for short- and long-term load transfers;
- Reconciling purchases of energy and invoices from Hydro One;
- Monthly billing of MIST customers;
- Providing daily pricing and NSLS into the CIS system for billing of non-MIST customers;
- Provide monthly load forecasting and accruals; and

- Implementation and operation of regulatory changes (including "Class A" global adjustment).

Meter Data

The Meter Data business unit is responsible for the accurate and timely processing of all meter read data for both conventional meters and smart meters. Business procedures and processes for this business unit have significantly changed since the introduction of smart meters. These changes include:

- Exceptions (errors) handling of reported MDM/R exceptions; and
- Exceptions handling of meter data for customers on two-tier billing as Enersource converts its eligible customers onto TOU billing.

In addition this business unit is responsible for:

- Processing and exceptions handling of meter data for customers that remain on mechanical meters (and therefore require conversion of their meter reads using the NSLS); and
- Locations setup and maintenance (for new services, services removal, and ESA records);

The deployment of smart meters and advanced metering infrastructure ("AMI") has allowed Enersource to reduce significantly its reliance on third-party, contract resources to collect meter reads. Smart meter data is now used to bill customers on regulated price plan ("RPP") rates. Contract meter readers are only used for a few remaining residential and small commercial customers with mechanical meters, or for meters with communication issues.

Enersource continues to transition its residential and small commercial customers to TOU billing and expects substantial completion by the end of May, 2012. Exhibit 9 Tab 2 Schedule 1 discusses this in detail.

Although there are savings related to smart meter reading, smart meters have also increased the complexity of existing business processes and introduced many new business processes. Some of these include:

- Daily operating and monitoring of TOU customer enrolment process with the MDM/R;
- Daily synchronizations, population, and updates of the MDM/R;
- Investigation and resolution of reported MDM/R exceptions (errors) associated with TOU, and MDM/R business processes; and
- Execution of testing cycles related to MDM/R application software upgrades.

In addition to meter reading responsibilities, the Meter Data business unit is responsible for:

- Managing all retailer settlement billing, agreements and activities;
- Monitoring and addressing meter reading “edit” reports that are essential for the maintenance of strong internal controls and timely billing;
- Communication with both residential and commercial customers to obtain access to meters;
- Preparing and reconciling printed bills for bill delivery;
- Setting up all new residential and commercial service connections in the CIS;

- Investigating unmetered power reports; and
- Administration related to installation of abloy locks for meter cabinets.

Customer Care Operating Cost Summary

Since 2008, the business units within the Customer Care division have seen a dramatic change related to their processes and procedures. These process changes have been driven by the introduction of Enersource's new CC&B system, the introduction of smart metering, TOU billing, individual metered suites ("IMS"), and a significant increase in the number of accounts deemed to be uncollectable.

To effectively manage the implementation and continued compliance with regulatory requirements (such as implementing TOU rates, achieving integration with the MDM/R, and new credit and collections regulations particularly with respect to low income customers), the Customer Care division has experienced several staffing changes since 2008. Overall, this division has had a decrease (which includes staff transferred to other divisions in the organization) in staffing levels over the 2008 Base Year. The total staff complement of Customer Care is shown in Table 1 below. The breakdown by employee type is also shown in Table 1.

The Customer Service business unit has had an increase of three permanent part-time union staff to handle the increase call volumes.

Overall, two non-union staff were transferred to a new Regulatory Affairs business unit in 2009. In 2011, the Settlements and Collections business units increased by two staff: an Accounts Receivable Manager, to comply with new regulations and reduce the allowance for doubtful accounts, and one inside union cashier position to help process electronic payments.

The Meter Data business unit also saw an increase of three inside union staff to ensure the ongoing compliance with regulations and accuracy of metering data. These three inside union staff members were transferred from the smart metering project in early 2012.

In 2012, the Collections business unit transferred two outside union staff to Metering Operations to address safety concerns, and transferred two non-union staff members to ISTS in 2012, in order to centralize CC&B computer operations and data analyst functions.

Table 1: Customer Care Number of Employees by Year and Type

Employee Type	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside	39	37	36	36	42	42
Outside	2	2	2	2	0	0
Non-Union	21	21	21	19	17	17
Ending Headcount	62	60	59	57	59	59

Below in Table 2 are found the Customer Care operating costs from 2008 to 2013. Note that Table 2 does not include bad debt expenses or late payment revenues, which are shown separately in Table 3 below.

Table 2: Customer Care Operating Costs by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$3,588	$3,042	$3,558	$3,686	$3,432	$3,672	$3,879
Benefits	1,070	1,010	1,048	1,050	1,497	1,730	1,855
Outsourced Call Centre and Collections	1,601	1,524	1,605	2,440	1,740	2,000	1,930
Staff Training	104	46	59	72	83	77	76
Communication and Other Costs	124	76	79	59	67	53	53
Bill Print, Delivery and Meter Reads	1,112	924	976	961	1,055	1,224	1,374
Winter Warmth	40	31	40	50	140	145	150
Total	**$7,639**	**$6,653**	**$7,365**	**$8,318**	**$8,014**	**$8,901**	**$9,317**

Customer Care costs have increased overall from 2008 rates to 2013 Test Year by $1,678, or 22%. The increase is primarily due to an increase in salaries and benefits, combined with significant increases in call centre, collections and billing costs.

Salary costs have increased by $291, or 8%, between 2008 and 2013 and account for 17% of the total increase in Customer Care costs from 2008 rates. .

Benefits expenses have increased $785, or 73%, and account for 47% of the increase in Customer Care 2013 Test Year costs from 2008 rates. This increase in employee benefits is mainly due to pension-related costs (OMERS).

The increases due to call centre and collections costs account for $329, or 20%, of the increase in Customer Care costs from 2008 rates.

The costs relating to the outsourced call centre has steadily increased since 2008 due to overall increases in the cost of power and Enersource's increased focus on customer accounts that are overdue. The number of calls received by Enersource has increased over 2008 by 11.5%, and is projected to increase by an additional 18% during 2012 and 2013.

Bad Debt and Late Payments Revenues

Since 2008, Enersource has experienced a significant increase in the amount and number of accounts deemed to be uncollectable. In the 2008 cost of service application, Enersource forecasted $1,575 of uncollectable accounts receivable and $420 of late payment revenue. The net impact on the 2008 revenue requirement was expected to be $1,155. In 2011, accounts receivables of $3,706 were deemed uncollectable and $2,068 of late payment revenue was recorded, for a net impact of $1,638. Enersource has attempted to mitigate this trend by hiring an Accounts Receivable Manager and selecting two new third-party collection agencies.

In the 2013 Test Year, the net impact of bad debts on Enersource's revenue requirement is expected to increase to $1,750. This is $595, or 52%, higher than 2008 rates.

Below is a table showing Enersource's bad debt expense and late payment revenue received or forecasted from 2008 to 2013.

Table 3: Bad Debt Expense and Late Payment Revenue, 2008 to 2013 ($000s)

Description	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Late-Payment Revenue	(420)	(408)	(413)	(1,379)	(2,068)	(1,800)	(1,800)
Bad Debt Expense	1,575	1,270	1,253	2,802	3,706	3,600	3,550
Net Impact	$1,155	$ 862	$ 840	$1,423	$1,638	$1,800	$ 1,750

In summary, the increase in Customer Care costs is attributable to:

- increased average compensation levels;
- increased employee benefits costs (mainly due to pension-related costs);
- increased call volume and bill delivery activities;
- increased activities levels due to added metering complexity and a significant increase in doubtful accounts;
- staff transferred from the smart meter project;
- increase in printing, postage, and courier service costs to deliver bills;
- increased telecommunications expenses, including the costs related to toll free telephone numbers; and
- increase in third-party contract costs for centralized payment processing.

Engineering and Operations Operating Costs

Engineering and Operations ("E&O") Overview

Enersource owns and operates the electricity distribution system in the City of Mississauga ("Mississauga" or "the City") that serves approximately 195,000 residential customers and commercial businesses. The Engineering and Operations ("E&O") division is responsible for the continued safe and reliable operation of the distribution system, while meeting all legislative, regulatory, and environmental requirements. This division incurs expenses related to the operations and maintenance of Enersource's underground and overhead distribution system as well as its substations. "Operations" is defined as work that encompasses actions of a detective, preventative, and/or monitoring nature. "Maintenance" is defined as the routine activity to ensure the equipment or device operates correctly (generally work performed in a reactionary manner based on the results of an Operations activity).

Substation maintenance includes automated switch corrective and preventative maintenance. Overhead maintenance includes insulator washing, overhead system inspections, transformer inspections and pole inspections and testing. Underground maintenance includes building vault inspections and dry ice cleaning of padmounted switchgear. The costs of these maintenance activities are incurred to ensure that Enersource continues to provide quality, reliable and cost-effective service to customers.

The E&O division consists of five departments:

1. Overhead Construction and Standards;
2. Asset Management Planning and Reliability;

3. Customer Engineering and Underground Construction;
4. Substations and Facilities; and
5. Maintenance and Operations.

The following evidence will provide an overview of each of these departments, their functions, and operating and maintenance costs.

1. Overhead Construction and Standards

The Overhead Construction and Standards department ("Overhead Construction") is responsible for overhead expansion and cable relocation, planned and emergency replacement of overhead pole lines, material standards review and approval, and overseeing Enersource's apprentices.

System expansion represents capital expenditures required to connect new customers or additional loads to the distribution system, and is typically an addition to the distribution system made either via a system enhancement and/or a new expansion.

The department is also responsible for reviewing and approving all materials and manufacturers used in Enersource's distribution system, with the exception of substations, street lighting, metering, and health and safety items.

Two issues of note that will affect the operating costs of the Overhead Construction department, an agreement with CN Railway ("CN"), and the apprenticeship program are described in the following sections.

CN Agreement

Enersource has an encroachment agreement with CN to lease their lands for Enersource poles. In January 2011, CN increased this leasing rate significantly.

Enersource began to relocate a number of lines from CN lands to roadways to reduce the costs and provide better access to key overhead plant. Most relocation projects will be completed in 2012. The encroachment agreement costs will be reduced to $250 in the 2012 Bridge Year and to $150 in the 2013 Test Year once the relocation projects are completed.

Apprentices

Overhead Construction oversees Enersource's Power Lineman and Cableman[1] apprenticeship program. Enersource's apprenticeship program was enhanced to prepare the next generation of skilled trades resources to mitigate the risk of shortage of skilled workers. Enersource can effectively utilize apprentices to operate, maintain, and expand the system. This succession program is proving its worth by producing very high quality candidates through a stringent screening and evaluation process. These apprentices need to complete a four-year apprenticeship before they are finally assigned to a department. By the end of 2011, Enersource had 20 apprentices within the E&O division and this successful program is anticipated to continue for the foreseeable future. Beginning in 2009, all apprentices were tracked in one business unit to improve efficiencies.

2. Asset Management Planning and Reliability

Enersource's Asset Management Planning and Reliability department provides system planning, reliability studies and reliability tracking. Cable locates are also managed in this department.

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[1] The masculine form of these names is born of convention. Enersource is pleased to be an equal opportunity employer.

System planning is a fundamental requirement for the effective development and management of a distribution system. The department provides short and long range planning direction for distribution system development, reliability improvements, asset inspection, maintenance and replacement programs, and increases to overall system capacity. A key output of this effort is the Asset Management Plan ("AMP"), which is produced by the department, and which is discussed at Exhibit 2 Tab 2 Schedule 2.

In addition, the department reviews new project connections for feasibility, performs switch optimization, load transfer and system loss studies, and advises the overhead and underground construction departments of future expansion requirements.

The department performs various system studies to review the existing status of the grid and identify areas of future development that will require expansion to the system. Enersource's feeders are also reviewed to ensure that they are within loading criteria and are properly backed up for emergencies. On a daily basis the department contacts the Control Room (described below) and reviews the system with the operators to identify issues. Daily monitoring and review of the Control Room's supervisory control and data acquisition ("SCADA") system and data identifies problematic areas in the system. Further information is gathered directly from the Region of Peel and the City of Mississauga to better understand system reinforcement requirements. The department produces overall electrical master plans for various planning locations in the City to indicate how certain areas of new development will be supplied.

The various system studies performed by the department allow Enersource to strategically plan its annual capital projects and perform preventative maintenance on the distribution system, all with the goal of ensuring that

Enersource maintains its reliability standards. Further discussion on system reliability is provided in below.

The Asset Management Planning and Reliability department also researches new devices and technologies, including animal protection methods, cable injection, and solid dielectric switchgear, to improve the system reliability. The studies are also incorporated into the AMP in which future resource and funding needs are established.

System Reliability

System reliability is a key performance measure for Enersource. Enersource uses industry standards to measure and benchmark system reliability performance. Enersource is an active participant of the Canadian Electricity Association's ("CEA") Service Continuity Committee ("SCC"). Among the various responsibilities of this committee is maintaining the CEA's system reliability performance definitions and a comprehensive database of reliability data. Enersource follows the guidelines set out by the CEA's Electric Power System Reliability Assessment program ("EPSRA") which governs system continuity statistics for the entire electrical system. Enersource implemented an Outage Management System ("OMS") in 2009 which enhanced its ability to track reliability statistics.

A key strategic goal of Enersource is to achieve high reliability levels and high standards of customer service. Enersource closely tracks and monitors customer service quality and reliability indicators, that correspond to Board's electricity service quality requirements ("ESQRs"). The results of these indicators for 2009 to 2011 are provided at Exhibit 2 Tab 3 Schedule 1. Tables 2 and 3 of this schedule provide the reliability results (SAIDI, SAIFI and CAIDI), in total, and excluding loss of supply, respectively.

Enersource acknowledges that certain reliability results in 2011 (specifically, SAIDI and SAIFI) have fallen outside of the most recent three year band, as required by the Board. Enersource continuously strives to improve on this performance to ensure customers receive the best possible service. Comparison to historical data is difficult due to implementation of Enersource's new Integrated Operating Model ("IOM") system in the latter part of 2009. With the new IOM system Enersource is capable of recording outage durations down to the second. This allows outages to be more accurately categorized. As a result, a significant number of outages that were previously categorized as momentary outages, with the new system are now being categorized as sustained outages. Thus, in relation to Enersource's historical indices, SAIFI has increased significantly, SAIDI has increased slightly, CAIDI has decreased significantly, and SAIFI(mi), also known as MAIFI, has also decreased.

As a result, many initiatives to improve reliability are addressed within the AMP at Exhibit 2 Tab 2 Schedule 2 Appendix 1. In addition, Enersource has placed greater focus on asset management planning as a key company initiative. The costs associated with this are discussed at Exhibit 4 Tab 1 Schedule 5.

Cable Locates

The cable locates function remains within the Asset Management Planning and Reliability department. Cable Locates provides electrical facilities locating and marking services for Enersource customers and contractors in accordance with the Electrical Safety Authority's ("ESA") "Guideline for Excavation in the Vicinity of Utility Lines". In 2010, Enersource initiated a "Call Before You Dig" program. This is now part of, and commonly referred to as, the "Ontario One Call" program.

Under the Occupational Health and Safety Act, all underground utilities must be located before digging. Ontario One Call allows homeowners and contractors to call first before they do any work that involves digging or excavating. This will help to prevent injuries, property damage, and inconvenient outages. In addition, damaging underground service can be expensive to repair, and can lead to legal action. Enersource recovers locating costs through distribution rates rather than end-user charges to encourage property owners and contractors to make use of this service.

Cable locating costs are related to the demand for these services and vary depending on the construction projects and economic development activities of the year. Enersource has experienced a 40% increase in the demand for this service since 2008 (from 20,000 to 28,000 locates annually) due to an increased construction volume within the City of Mississauga as well as ongoing Enersource initiatives to inform contractors of the importance of acquiring locates.

Enersource's guidelines in responding to customer locate requests are as follows:

- Perform emergency locate requests within 2 hours, and
- Respond to 90% of locate requests within 5 days to comply with OEB and ESA requirements.

The fluctuating work volume is a big challenge for the Cable Locates department. The department typically receives 400 monthly locate requests during the winter months (low construction season) and 3000 requests during summer months (high construction season). To mitigate the risk of shortage or excess of workforce, Enersource outsources cable locates work as required.

3. Customer Engineering and Underground Construction

The Customer Engineering and Underground Construction ("Customer Engineering" or "Underground Construction") department plays an important role in the expansion and improvement of the distribution system in order to meet both future growth and customer expectations. The group ensures that yearly plant additions and improvements are economically feasible, reliable, safe, and meet public acceptance.

Electrical distribution planning is based on land use information and plans (including subdivision concept and draft site plans, re-zoning applications, public utility coordinating committee ("PUCC") applications and road closures) provided by the City's Planning and Building Department.

All of the aforementioned plans are reviewed by Customer Engineering to ensure the submitted plans meet Enersource's technical requirements and there are no conflicts with foreign utilities. Any conflict is conveyed to the City and to the applicant.

New subdivision developments (residential and commercial) in the City are partially funded by the developers through a capital contribution. The capital contribution is determined by the requirements defined in Chapter 3 of the Board's *Distribution System Code* ("DSC").

The Customer Engineering department is also involved in:

- Design, construction, inspection/energization of underground rebuilds;
- Service layout design, construction, inspection/energization of industrial/commercial and residential connections;
- Conducting feasibility studies, reviewing designs, and performing inspections to allow connections of microFIT and FIT projects; and

- Disconnecting and reconnecting customers upgrading their electrical service.

A significant challenge faced by Customer Engineering is working with the City of Mississauga to meet the goals and objectives of the "Downtown21" Master Plan (www.downtown21.ca). Downtown21 is the City's vision to create green landscape areas for pedestrian, bicycle-friendly activity, and the Hurontario-Main LRT project. The City wishes to establish the Square One Shopping Centre area as the heart of Mississauga. This will involve significant relocation of existing Enersource assets and the installation of new plant.

4. Substations and Facilities

The Substations and Facilities department is responsible for ensuring the proper function and design of Enersource's substations as well as the Administration Office and the Operations Centre.

Enersource has purchased a new building at 2185 Derry Road West that will serve as the new Administration Office, with staff starting to move in by September, 2012. The Mavis Road facility will be reconfigured back to its original intended use as an Operations Centre. This is discussed in detail at Exhibit 2 Tab 2 Schedule 5.

The operating costs associated with the Administration Office are discussed at Exhibit 4 Tab 1 Schedule 12. The remainder of this section on Substations and Facilities will describe the initiatives to ensure the reliability and performance of Enersource's substations and related equipment.

Enersource owns and operates 66 municipal substations ("MS") across the City. Substations are used for the delivery of power, voltage transformation, and switching purposes. Enersource's substations play a key role in dividing the City

into smaller sections. They help to minimize any disruption to the continuity of service when a section is not functional, during a fault or maintenance period.

Enersource delivers in the order of 8,000 GWh annually to its customers. Approximately 37% of the power is delivered to large industrial and commercial customers, who account for only 0.2% of the total number of Enersource customers. Individual large customers can add significant load to the system and provide unique challenges to connect and supply. Some customers may need to be connected in areas where there is insufficient capacity, necessitating construction of new feeders or substations to meet their specific needs.

A substation consists of:

- Instruments for measuring current and voltage such as transformers;
- Protective equipment such as circuit breakers, for interrupting a line's current, or surge arresters, which protect transformers from a voltage spike caused by lightning;
- Control devices, such as disconnect switches and busbars, which are used to switch energy from one line to another almost instantaneously; and
- Other instruments, such as reactors, capacitors and compensators, used to control the voltage in substations.

The work programs required to maintain substations and automated switch facilities include corrective maintenance and preventative maintenance. Each of these programs is described below. Planned substation maintenance programs are also discussed below.

Substation and Automated Switch Corrective Maintenance

The operating costs for substation and automated switch corrective maintenance

include:

- Emergency responses to equipment failures; and
- Correcting situations where there is a likelihood of failure that could cause a power interruption or present a safety hazard.

When a substation component fails, typically 1,000 to 5,000 customers experience a service interruption. Emergency and corrective maintenance work must be carried out in a timely manner in order to restore service safely and to maintain reliability. In most cases, the component (e.g., instrumentation transformers, battery, insulator, connector, relay, or switch) can be repaired, temporarily bypassed, or replaced. The failure of a larger component (e.g., a power transformer) may require moving the equipment off-site and repairing it at a central location.

Substation and Automated Switch Preventive Maintenance

Enersource is utilizing a preventive maintenance approach to efficiently and effectively sustain its substations. Enersource's preventive maintenance program relies on analysis of failure modes, causal impacts, and asset criticality to determine the maintenance tasks.

Planned Substation Maintenance Programs

- Substation inspections - Enersource's substations are inspected bi-monthly to identify problems and safety hazards prior to initiating the planned maintenance work;

- Power equipment maintenance - By performing inspections and testing on power transformers and batteries, Enersource obtains an advanced indication of possible failures. Dissolved Gas-in-Oil Analysis (DGA) and Doble testing

provides an assessment of the condition of power transformers. This provides predictive measures to plan maintenance and replacements to mitigate potential failures. Testing of batteries and charging systems reduce the probability of premature battery failure going undetected;

- Asset condition assessments - The asset condition assessment ("ACA") prepared by Kinectrics Inc. (and discussed at Exhibit 2 Tab 2 Schedule 2), has allowed Enersource to prioritize and allocate resources to replace or repair substation equipment such as substation power transformers or circuit breakers;

- Substation grounds and site maintenance (e.g., weed control, snow removal, fence repair, access road maintenance, site drainage, foundation repairs) - The maintenance of substation buildings and properties allows Enersource to secure energized equipment from acts of vandalism or hazards to the public; and

- Maintenance of automated switches – Enersource's underground system has a number of automated load centers and the overhead system has a number of automated overhead switches that can be remotely operated via the SCADA system. They facilitate the restoration of power after an interruption and improve overall distribution system reliability. Enersource maintains automated switches on a two-year cycle. They are taken out of service, cleaned, aligned, lubricated, and then re-installed, operated in the field, and communications to the Control Room via the SCADA system is confirmed.

The entire substation itself is maintained on a five-year cycle. A planned maintenance program reduces the risk of equipment failure, which can negatively impact reliability to a large number of customers. Planned maintenance also

limits the risk of unplanned maintenance in the future and ensures that equipment serves to the end of its design life.

The benefits of the planned maintenance of substations include:

- preserving operational integrity;
- correcting equipment defects before they cause outages; and
- improving overall reliability of service to customers.

Appendix C of the DSC requires that LDCs inspect substations on a regular basis to identify obvious structural problems, hazards, and signs of vandalism. Enersource's substations are inspected monthly to identify problems and safety hazards prior to initiating the planned maintenance work.

5. Maintenance and Operations

The Maintenance and Operations ("M&O") department has several primary functions: maintenance and operations design, overhead maintenance, underground maintenance, control room, trouble trucks, and forestry. Each of these functions is described below.

Maintenance and Operations Design

The M&O design group provides administration for maintenance projects. The design group creates drawings for maintenance and small customer-related projects. This group works closely with the Asset Management Planning and Reliability group to address system concerns, identify upcoming expansion as well as system reliability projects. The M&O department also works with the project scheduler to plan and complete maintenance related projects and

provides maintenance support activities such as new service connections and disconnections.

Overhead Maintenance

The overhead distribution system includes approximately 1,800 km of distribution and subtransmission circuits strung on approximately 20,000 poles. The overhead system includes over 16,000 switches, 5,000 overhead transformers, as well as surge arrestors, insulators, guying wires, and anchors. These assets are located primarily on public roads with a small percentage of poles situated within easements on privately owned lands.

The Overhead Maintenance department is responsible for following up on overhead deficiencies that cannot be immediately repaired by a trouble truck. They also react immediately to emergencies, such as broken poles or system outages from storms, to ensure public and crew safety.

It may be necessary to follow up a trouble call to make permanent repairs or to conduct further maintenance to ensure system integrity. When a feeder circuit breaker operates at a substation due to an unknown or transient fault, Enersource patrols the feeder to determine the cause of the fault and takes appropriate remedial action upon determining the source of the problem.

Enersource's overhead preventative maintenance programs include:

- Insulator washing;
- Infrared Inspection;
- Transformer inspection; and
- Pole inspection and testing.

Each of these programs is described below.

Insulator Washing

A failure of an insulator is typically caused by contamination, commonly from road salt. Contamination of insulators, if left unattended, can lead to many problems, including pole fires, which will jeopardize the system's reliability.

Approximately 50% of the overhead system is comprised of traditional porcelain insulators which, under certain weather conditions, can be affected by contamination. On a proactive basis throughout the winter months, the porcelain insulators are power washed to remove contamination and reduce the potential for outages. To reduce the impact of contamination, all new polymer insulators are made from a contamination-resistant material.

Infrared Inspection

Enersource conducts an annual infrared scanning of the overhead system to detect equipment failures. These scans can be performed while the equipment is in service. These inspections detect 'hot spots' which may cause potential failures before the components completely fail. Failures can cause considerable damage to adjacent equipment, potentially long outages and costly repair work. Infrared inspection information provides advance warning of impending failures. Any equipment that exhibits an unusual 'hot spot' is repaired or replaced, as required. Enersource typically detects and repairs about 40 hot spots each year.

Transformer Inspection

Enersource uses SCADA to monitor substation transformers. Inspections are done immediately if issues are noticed by the system control operators. A catastrophic failure of a critical transformer would result in power outages in the downstream network and could cause significant economic and environmental

challenges. SCADA technologies help maximize asset performance and reduce unexpected transformer failure and subsequent power outages through alerts, detection, diagnosis, and prognosis. By monitoring different conditions within the transformer, such as gas levels, smart sensors will detect and report potential problems in real-time. The information is analyzed by advanced software, helping predict and prevent a potential transformer failure before it happens.

Each customer on the system is associated with a smaller transformer. Transformers are key components of an electric grid. Thus, they are inspected whenever a crew performs any work on a transformer to ensure they are in good condition.

Pole Inspection and Testing

Enersource has commenced a pilot pole inspection and testing program to enhance the system reliability. This process will expand going forward. The wood pole inspection program looks for decay and applies treatment, if necessary, to reduce the risk of pole failure and extend the life of poles, to enhance the reliability of the system and public safety. Higher risk poles will be replaced or repaired sooner as they are found on the system.

Underground Maintenance

Enersource's underground distribution system includes approximately 3,500 km of distribution and subtransmission circuits. The underground system also includes approximately 20,000 underground distribution transformers. There are approximately 800 padmounted switchgear units in the distribution system of which 8% are motorized and monitored via SCADA. The average installed age of these units is 19 years and 22% of the units are older than 25 years. Like the

overhead system, these assets are primarily located on easement on privately-owned lands with a small percentage existing on public road allowance.

In response to trouble calls, follow-up repairs are made to ensure system integrity. These include repairs to secondary cables and primary cables, terminations, and connectors.

Underground maintenance projects are subject to variable weather conditions. Most digging for underground maintenance is scheduled during the warmer months. Due to its seasonality and to avoid excess labour and equipment costs during the winter season, Enersource outsources most of its underground civil work to reduce the overall costs and increase work force flexibility. The outsourced maintenance projects include dry-ice cleaning, graffiti removal, secondary cable repairs, and hydro-vac services.

Enersource's primary underground preventative maintenance programs are building vault inspections, submersible transformer vaults inspections, and dry-ice cleaning of pad-mounted switchgear. Each program is described in the following sections.

Building Vault Inspections

Building vaults are rooms found in, or associated with, apartments or industrial/commercial buildings that contain transformers and associated equipment owned by Enersource. They provide dedicated electrical supply to the building in which they are located. Vaults require periodic inspection to ensure their integrity and confirm and update system records. Enersource inspects vaults in coordination with the property owner's fire alarm equipment testing requirements. Fire alarm equipment, such as smoke and heat detectors,

is typically located in the building vaults. As a result of these inspections, follow-up repair, maintenance or equipment replacement is scheduled as appropriate.

Dry-Ice Cleaning of Padmounted Switchgear

Padmounted switchgear is enclosed in metal cubicles, typically located on easements that are frequently exposed to contaminants (e.g., road salt). If contamination is left unaddressed, major equipment damage could result that would interrupt service to customers. To reduce the impact of such contamination, these units are cleaned using a dry ice process. The process allows for the cleaning of energized switchgear. The use of dry ice decreases maintenance costs, eliminates customer interruptions, and avoids switching, thereby removing the associated safety concerns and freeing up manpower.

Control Room

Control Room ("CR") costs are related to the 24-hour monitoring and operation of the distribution system through Enersource's control centre. CR costs primarily consist of manpower costs for highly-trained system control operators ("SCO") and costs for supervisory control circuits, two-way radio systems, and SCADA maintenance. Enersource uses SCADA to control the electric grid, which includes 66 municipal substations and over 25,000 distribution transformers.

The control room is linked to the distribution system by a data communication network and information is processed by a SCADA system comprised of hardware, software, and supporting communications equipment which provide the tools for SCOs to efficiently and effectively monitor and operate the electric distribution system. The SCADA system provides real time operating information to SCOs, who use the information to optimize and react to system issues. Improved customer service is achieved through better system reliability, and

reduced response times in the event of system disturbances. The SCADA system also manages the operation of a number of remotely operable distribution switches, and through the operation of these remote switches, an SCO can reduce outage times experienced by customers.

The CR team functions allow for both planned and preventative maintenance on the distribution system, thereby improving reliability. Continued investments in control room equipment will ensure the same high quality and standard of service.

Trouble Truck

Mississauga is one of the largest cities in Canada and Enersource has many industrial and commercial customers that depend on a reliable supply of power to run their operations. It is critical to respond quickly, safely, and efficiently to power interruptions or to requests for assistance from emergency services (e.g., police and fire).

Enersource's trouble response crew, referred to as a 'trouble truck', is available 24 hours a day, 7 days a week. Trouble trucks are responsible for emergencies such as cable faults, pole transmission hits, pole fires and to make temporary and permanent repairs. When customers call with a power issue, a trouble truck is dispatched for emergency repair. Trouble trucks also perform basic maintenance on underground and overhead equipment.

Forestry

To ensure public safety and the reliable operation of the distribution system, Enersource maintains clearance around its distribution lines on a cyclical or as-

needed basis. The tree-trimming cycle may vary depending on the extent of storm damage, health of trees, and vegetation type.

The forestry, or tree trimming, program manages the adequate clearance between energized equipment and trees branches in order to:

- Maintain an acceptable and sustainable level of reliability;
- Manage safety hazards presented by trees in close proximity to energized lines;
- Minimize environmental and social impacts; and
- Reduce the frequency outages related to tree contacts.

Historically, tree contacts account for approximately 7% of Enersource's overall outage time. Enersource's priority is to trim trees that are in close proximity to critical overhead lines. Typically, trees are trimmed on a four-year cycle and in coordination with the City's forestry department (to ensure compliance with City by-laws on the removal or trimming of City-owned trees). Enersource notifies, and at times consults with, property owners who may be impacted by tree trimming or tree removal.

E&O Operating Cost Summary

Overall, the E&O division has had a net decrease of two positions since 2008. During 2011, this division was restructured to provide a stronger focus on customer service, staff development, and asset management. This restructuring created the five E&O departments that have been described above.

Table 1: E&O Number of Employees by Year and Type

Business Unit	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside	29	27	27	27	27	27
Outside	118	116	115	114	114	115
Non- Union	24	27	27	26	27	27
Total	**171**	**170**	**169**	**167**	**168**	**169**

Below in Table 2 are found E&O operating costs and recoveries from 2008 to the 2013 Test Year. Note that Table 2 does not include operating costs related to the asset management planning initiative, which are discussed and shown separately in Exhibit 4 Tab 1 Schedule 4.

Table 2: E&O Operating Costs by Type and by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$ 6,631	$ 6,299	$ 7,506	$ 7,255	$ 7,575	$ 7,889	$ 8,411
Benefits	2,439	2,080	2,422	2,856	3,368	3,495	3,733
Distribution System Maintenance	2,732	2,908	3,624	3,611	3,826	3,770	4,082
SCADA Circuit Conversion & Maintenance	310	345	413	432	513	535	555
Substation Property Taxes	597	595	593	600	597	630	650
Locate Services	259	380	467	540	610	580	611
Tree Trimming	205	225	219	220	245	225	288
Other Costs	693	561	514	468	654	643	555
Recoveries	(4,431)	(4,876)	(4,359)	(4,161)	(5,158)	(4,705)	(4,962)
Accounting IFRS Change – Overhead Burdens					2,042	2,520	2,261
Total Costs	**$ 9,435**	**$ 8,517**	**$11,399**	**$11,821**	**$ 14,272**	**$ 15,582**	**$ 16,184**

E&O operating costs have increased overall from 2008 rates to 2013 Test Year by $6,749, or 72%. The increase is primarily due to an increase in salaries and

benefits combined with rising maintenance costs associated with an aging distribution system, and significant increases due to the conversion to IFRS.

Salary costs have increased by $1,780, or 27%, and account for 26% of the total increase in E&O costs from 2008 rates.

Benefits expenses have increased by $1,294, or 53%, and account for 19% of the increase in E&O 2013 Test Year costs from 2008 rates. This increase in employee benefits is mainly due to pension related costs (OMERS).

Increased costs related to the accounting changes due to the conversion to IFRS are discussed below. Offsetting the increased operating costs are higher recoveries from Enersource affiliates. This is also discussed below.

Change in Capitalization Policy

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP are not allowed under IFRS. These costs, referred to as overhead burdens, have resulted in an increase in Enersource's operating costs. E&O costs have increased by $2,261 in the 2013 Test Year compared to 2008 rates due to these overhead burdens. Please refer to Exhibit 2 Tab 1 Schedule 1 for further details on the change in capitalization policy.

In summary, the increase in E&O operating costs is attributable to:

- Increased average compensation levels;
- Increase in employee benefits (pension-related OMERS costs);

- Increased costs to convert the SCADA telephone circuits from an analogue to a digital IP network;
- A change in Enersource's capitalization policy;
- Increase in underground maintenance and repair work due to a large number of cable faults; and
- Increased cable locates costs due to focused marketing efforts of Enersource and the "Call Before you Dig" program.

Asset Management Plan Initiative Costs

A formal comprehensive Asset Management Plan ("AMP") is critical for asset-intensive businesses such as electrical distribution utilities. Fundamental requirements of effective development and management of a distribution system are prudent planning, strategy, mission, and values. The AMP provides planning direction for distribution system development, sustainment, reliability, asset inspections, maintenance, and replacement programs, as well as increases to the overall system capacity.

Enersource has developed a detailed and integrated AMP that identifies key distribution system maintenance and replacement programs over a five-year planning horizon. The discussion is found at Exhibit 2 Tab 2 Schedule 2 and the AMP itself at Appendix 1 of that exhibit. The AMP programs have been developed utilizing key asset metrics, including age and asset performance, in order to prioritize system components which require maintenance or replacement, collect information on distribution system components that may fail in the near term, and implement maintenance programs to reduce outages. The scope of the plan encompasses programs and major projects that are required to sustain Enersource's electrical system.

The objectives of the AMP are to:

- Report on the performance of the distribution system;
- Identify risks and challenges that would adversely affect the ability to deliver economically reliable power to the City of Mississauga; and

- Present a multi-dimensional over-arching strategy and tactical plan for investing and maintaining assets in order to effectively achieve the lowest long-term owning costs.

The AMP details how Enersource manages, maintains, and reinforces the electrical distribution system in a cost effective manner. In addition, it reviews the capital, operating and reliability trends over the past five years. The new initiatives in asset management reflect the change from corrective maintenance to preventive maintenance of the distribution system. Enersource will conduct more inspections on transformers, switchgears, and vaults, combined with pole tests to identify and rectify problems more effectively.

To address the impending increase in the number of assets that are expected to reach their useful life over the next two decades, the AMP also identifies several initiatives under development and consideration to closely monitor, analyze, and evaluate asset management activities in order to refine the approach required to meet the expected increase in replacement rates.

The AMP emphasizes a continued focus on managing the aging infrastructure, particularly in the management of poles, underground cables, distribution transformers, substation transformers, and substation switchgear. Given the large expansion of the system in the 1970's, 1980's, and 1990's, a considerable amount of asset replacement is expected to commence within the next four to five years, continuing over the next decade and beyond. This must be prudently managed, with due consideration to meet the needs and expectations of Enersource customers.

Asset Management Plan Initiative Operating Costs

In 2012 and 2013, Enersource will focus on implementing the recommendations of the 2012 AMP and continue to update the plan annually. The implementation of the AMP necessitates additional staff and related costs to collect and analyze operational and asset information that had not been collected and analyzed previously. It will also require additional software and analytical methods, to make more-informed decision, optimize its asset decision in order to enhance system reliability and to enhance its predictive capabilities.

Enersource will add five dedicated staff towards the AMP initiative in 2012 and 2013. Table 1 identifies the employee types for these positions.

Table 1: AMP Initiative Employee Type by Year

Asset Management Plan Initiative	2012 Bridge	2013 Test
Inside	-	1
Non-Union	1	4
Total	**1**	**5**

Table 2 lists AMP initiative operating costs from 2011 Actuals to 2013 Test Year.

Table 2: AMP Initiative Operating Costs by Type and Year ($000s)

	2011 Actual	2012 Bridge	2013 Test
Salaries	-	27	408
Benefits	-	10	167
Distribution System Inspections	-	200	400
Asset Condition Assessment	120	50	75
Software Maintenance	-	-	100
Other Costs	-	-	3
Total Costs	**$ 120**	**$ 287**	**$ 1,153**

AMP initiative operating costs include salary and benefits expense, distribution system inspections, professional services for an asset condition assessment

("ACA"), and asset management plan and software maintenance costs related to the capital asset management software.

Enersource has included five new positions for the AMP initiative in the 2013 Test Year. The AMP identifies the need for aggressive inspection and maintenance of the distribution system assets. Included in the 2013 Test Year is $400 to conduct padmount transformer inspections, pole tests, switchgear inspections, and vault inspections.

Enersource engaged the services of Kinectrics Inc. ("Kinectrics") to perform an ACA on Enersource's distribution system assets and to assist with the development of the AMP. The ACA involves the development of health indices for distribution system assets, performing stress-based risk assessments for power transformers and circuit breakers, developing an optimal asset replacement plan based on the health index and economic life of assets, identifying data gaps, and providing a prioritized plan for closing the data gaps. Enersource used several sources of data to assess the status of the assets in its distribution system and to assist with determining the capital and operating investments to be made. The AMP also includes a risk assessment that identifies and prioritizes risks associated with managing and expanding the distribution system assets. The 2013 Test Year also includes software maintenance costs related to the capital purchase of asset management software.

In summary, the increase in the AMP initiative costs is attributable to:

- Increased costs to inspect, gather, and analyze all information on distribution assets;

- Develop initiatives to closely monitor and evaluate asset management activities in order to refine the approach needed to meet the expected increase in replacement rates;
- Increased staff levels dedicated to the customer-focused asset management initiative;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs); and
- Increased software maintenance fees.

Metering Operating Costs

Enersource's Metering department is responsible for all aspects of metering in the distribution system in the City of Mississauga. This includes the installation and monitoring of residential, commercial, industrial, and wholesale metering facilities. Compliance with regulatory and legislative requirements with respect to metering, such as implementing smart meters and time-of-use ("TOU") rates, is a necessary component of metering asset investment programs. The Metering department is also responsible for implementing procedures to comply with regulatory requirements related to accuracy and metering certification and re-verification. Enersource purchases all meters calibrated and sealed, in compliance with Measurement Canada standards.

The Metering department is responsible for installing, maintaining, and ensuring accurate metering assets in the following categories:

- Smart metering; and
- Conventional meters, including electro-mechanical meters and interval meters.

The Metering department is currently working on the following major projects:

- Smart meter deployment completion (access issues, customer refusals, hazardous meter base inspections, and 600 V installations);
- Individual metered suites ("IMS") for new condominiums;
- Suite metering retrofit project to replace the old single bulk meters with IMS for existing buildings/condominiums;
- Large general service ("GS") and IMS meter re-verification to ensure Measurement Canada compliance; and

- Analysis of large and small GS meters to ensure correct installation and accurate recording of electricity usage.

Smart Metering

The province's mandated Smart Metering Initiative is a capital investment project regulated by the OEB. The main objective is to allow residential and small GS customers to manage their electricity costs by shifting some electricity use to off-peak hours.

As of December 31, 2010, Enersource completed installations for 99% of its residential customers, and 85% of its GS less than 50 kW ("GS<50 kW") customers. This combined total represents 98% of Enersource's customers mandated to receive smart meters. By the end of May, 2012, Enersource is forecasted to complete installations for almost all eligible customers.

A summary of smart meter installations by Enersource as at the end of 2011 is shown in Table 1 below.

Table 1: Smart Meter Installations by December 31, 2011

Smart Meter Installations	Completed	Remaining
Residential	166,601	924
GS<50 kW	15,947	1,680
GS>50 kW[1]	1,410	0

Enersource has installed smart meters for virtually all Residential and GS<50 kW customers, with the exception of a small number of customers that have either refused allowing Enersource access to complete the installation ("customer refusals"), have certain installation-related technical issues or hazardous meter bases, or are 600 volt ("600 V") small GS accounts. It is Enersource's intention to complete most of these installations by the end of the second quarter of 2012, but it may take considerable additional time and effort to achieve 100% compliance.

As this program is in its final stages, technical crews are resuming regular ongoing maintenance of the installed residential and small GS smart meters, as well as large GS metering equipment. These changes are reflected in the increased operating costs for 2012 and 2013.

[1] Due to the communal meter room design of a few buildings, Enersource replaced the mechanical meters with smart meters for this small group of GS>50 kW demand customers who would benefit from wireless smart meter network meter reading.

In previous applications[2] to the Board, smart meter expenses have been shown separately and recovered by means of a smart meter funding adder and a variance account[3]. Enersource's Smart Meter Implementation Program ("SMIP") is substantially complete, and meter expenses have been treated as part of the regular distribution revenue requirements and included in base distribution revenue for the 2013 Test Year.

Further discussion on the costs, rate riders, and disposition of the smart meter deferral accounts is discussed at Exhibit 9 Tab 2 Schedule 1.

Individual Metered Suites

IMS refers to owner/tenant-specific individual smart meters (also called "smart suite meters") installed in order to measure energy usage in the individual suites of condominium and apartment buildings.

In order to support the government of Ontario objective to develop a culture of conservation, Enersource is installing IMS, when requested, in new multi-residential buildings, to record when and how much electricity is used by each customer.

By the end of 2011, Enersource installed 7,342 IMS in newly constructed condominium buildings.

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[2] EB-2011-0100, EB-2010-0078, EB-2009-0193, EB-2007-0706, EB-2007-0063, EB-2007-0523, and EB-2005-0529.

[3] Uniform System of Account 1555.

Retrofit Program

Enersource's suite metering retrofit program permits owners and/or landlords to replace a single bulk meter with IMS in existing buildings and condominiums.

Replacing single bulk meters with IMS promotes a culture of conservation and provides consumers the tools to monitor and control their own electricity consumption. By the end of 2011, Enersource installed 1,115 retrofit IMS in existing multi-residential buildings.

Meter Re-Verification

As specified by Measurement Canada standards, each year a grouping of randomly sampled meters are tested for accuracy. When any of the sample groups fail to meet the specified requirements, all the meters in that sample group are replaced.

As a result of Enersource's SMIP, Measurement Canada in 2007, approved meter re-verification exemptions for residential and small GS meters. These exemptions, combined with mass replacement of conventional meters with smart meters, are reflected in the reduced meter re-verification costs from 2008 through 2011.

Beginning in 2012, Enersource will be required to re-verify IMS, residential, and small commercial smart meters. The costs associated with these meter re-verifications have been included in Enersource's 2012 Bridge and 2013 Test Years.

Meter Inspection and Certification

According to Measurement Canada, all newly installed suite meters need to be inspected and certified to Measurement Canada's SE-04 specification within one year after installation. Enersource currently completes the SE-04 inspections as the final step in commissioning an IMS building. Enersource has forecasted one-time costs of $141 and $211, for 2012 and 2013, respectively, for a total of $352, to certify existing IMS installations that were not previously inspected. Enersource has 26 buildings that require the SE-04 certification. This work will be completed during 2012 and 2013. Since these costs are not recurring, Enersource believes that these costs should be recovered and amortized over four years to coincide with the 2013 Test Year plus IRM term. In the calculation of its 2013 revenue requirement, Enersource has excluded $211 from 2013 Test Year operating, maintenance, and administration ("OM&A") costs, but has included $88, representing one-quarter of $352, the total one-time certification costs. Table 2 below provides the estimated costs to comply with SE-04 certification.

Table 2: One-Time Measurement Canada SE-04 Certification Costs by Year ($000s)

	2012 Bridge	2013 Test	Total
SE-04 Certification Costs (to be recovered over four years)	$ 141	$ 211	$ 352

Metering Employee Count

The Metering department has made several organizational changes since 2008, that were necessary as part of Enersource's evolution from a traditional utility model to more of a progressive business model. Overall, the Metering

department has seen a net increase of two positions since 2008 due to the transfer of two outside union staff from Customer Service during 2012. This is illustrated in Table 3 below.

Table 3: Metering Numbers of Employees by Year and Type

Employee Type	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside	3	5	6	7	2	2
Outside	10	10	10	10	12	12
Non-Union	9	8	8	9	10	10
Total	**22**	**23**	**24**	**26**	**24**	**24**

Metering Operating Cost Summary

Below in Table 4 are found the Metering operating costs from 2008 to 2013.

Table 4: Metering Operating Costs by Type and Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$ 613	$ 681	$ 982	$ 1,056	$ 1,116	$ 1,066	$ 1,307
Benefits	289	411	436	509	668	572	697
Recoverable Salaries/Benefits	(118)	(555)	(812)	(939)	(465)	(198)	(474)
Material and Meter Reads	50	43	54	67	151	71	92
Physical Meter Inspections	66	44	27	13	64	85	100
Meter Re-Verification	80	38	20	8	10	125	135
Wireless Meter Communication	-	-	-	-	-	-	160
Total Metering	**$980**	**$662**	**$707**	**$714**	**$1,544**	**$1,721**	**$2,017**

Overall Metering costs have increased from 2008 rates to 2013 Test Year by $1,037, or 106%. The increase in salary costs of $694 comprises 67% of the total increase in Metering costs.

The salary costs increase is predominantly due to staffing reallocations. The reallocation of staff from SMIP-related capital work in 2008-2011 to ongoing operating work in 2012 as well as the transfer of two outside union staff from Customer Service comprises the majority of the increase.

Meter re-verification costs increased largely due to the increased scope of Measurement Canada requirements which now include IMS installed in

condominiums that must be re-verified prior to their seal expiry date. In addition, the Measurement Canada exemption from re-verification of meters due to the SMIP has expired and now requires Enersource to restart the meter re-verification program. These operating costs are new in 2012 and will form part of Enersource's ongoing operating costs.

An increased number of renewable generation projects due to the Green Energy Act has contributed to expanded efforts from the Metering group. Enersource has been able to absorb such effort with the existing complement of staff.

In addition, an increase to the 2013 Test Year by $160 is attributed to costs related to wireless communications networks required as part of the Advanced Metering Infrastructure ("AMI").

Benefits expenses have increased $408, or 141%, and account for 39% of the increase in Metering 2013 Test Year costs from 2008 rates. This increase in employee benefits is mainly due to pension-related costs (OMERS).

In summary, the increase in Metering operating costs is attributable to:

- Increase in overall staff levels due to the transfer of employees from other divisions;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs); and
- Increase in meter re-verification and wireless network costs.

Enersource Executive and Administration Operating Costs

The operating, and administrative costs of Enersource Hydro Mississauga Inc. ("Enersource") include expenses from two main administrative business units that oversee the management of Enersource. Within Enersource is the Executive and Administration group (E&A") which oversees the capital, operating, and maintenance activities within Enersource. The second main administrative group is within Enersource Corporation ("EC") which provides shared services to the utility for financial management, legal, and other functions. Greater detail on the corporate and utility organizational structure is found at Exhibit 1 Tab 1 Schedule 9. Further detail on the organizational shared services arrangement and the allocation of these costs is found at Exhibit 4 Tab 4 Schedule 1.

The E&A business unit provides Enersource with strategic oversight and operational direction and captures the costs associated with the Executive Vice President and Chief Operating Officer and senior management staff from the following five main organizational areas:

- Engineering and Operations ("E&O");
- Health, Safety and Security ("HS&S");
- Customer Care;
- Information Solutions and Technology Services ("ISTS"); and
- Regulatory Affairs ("RA").

The E&O division is responsible for the effective and efficient construction, operation, and maintenance of Enersource's distribution system. In early 2011, Enersource realigned the E&O division to provide a stronger focus on three key requirements: customer service, people development, and asset management.

In late 2011, Enersource renewed and incorporated its focus on asset management by creating a Director of Asset Management and Strategic Projects position. This new role provides leadership for Enersource's FIT and microFIT coordination activities, and provides synergies by focusing on the government's *Green Energy and Green Economy Act* ("GEA"), as well as smart metering, individual metered suites ("IMS"), and time-of-use ("TOU") implementation. These areas are discussed in detail at Exhibit 4 Tab 1 Schedule 4, Exhibit 4 Tab 1 Schedule 5, and Exhibit 4 Tab 1 Schedule 6.

The HS&S division was transferred from EC in 2011 to better align safety training and operational processes. The focus of the HS&S division is to place safety first, to promote and provide safety in and outside the workplace, and provide safety-based systems/programs to all Enersource employees. Exhibit 4 Tab1 Schedule 2 includes details.

The Customer Care division is responsible for the full meter-to-cash processes as well as responding to all customers inquiries. See Exhibit 4 Tab 1 Schedule 3 for details.

Enersource's ISTS division focuses on enhanced internal client service, higher computerized system performance, and business-driven strategic capital investments. Details are found at Exhibit 4 Tab 1 Schedule 9.

The RA division manages the OEB regulatory process, relationships, and enables policy influence, and further details are found at Exhibit 4 Tab 1 Schedule 10.

Additional strategic issues that are being addressed by the E&A business unit include:

Transitioning from Growth to Maintenance and from Greenfield to Intensification

The City of Mississauga ("City") has declining greenfield development and is shifting to redevelopment, infill, and intensification. The City has reported that over 94% of its land is now developed. In 2012, expansion and new construction initiatives continue with the completion of the Bus Rapid Transit System and Downtown 21 projects, and numerous condominium developments. The distribution system enhancements will follow this shift in emphasis from growth-driven to maintenance-driven investments, and from traditional underground services to deep (duct and manhole) services in the downtown core.

Best-in-Class Performance

As Enersource's distribution system ages, proactive refurbishment is essential to maintain the system's performance standards and customer service objectives.

Many factors, such as weather, customer loading, growth, and technology, impact the distribution system and, in turn, Enersource's reliability performance measures - System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI").

Modest organic growth has continued with new residential, industrial, and commercial customers, creating pockets within the City where additional or more flexible capacity is required.

Enersource's Integrated Operating Model ("IOM") is providing vast amounts of outages data which are being transformed into valuable information that is enhancing the decision-making process within the Asset Management Plan ("AMP") and associated strategies. The AMP is found at Exhibit 2 Tab 2 Schedule 2 Appendix 1. Enersource makes strategic investments including

distribution system enhancements and smart grid technologies which provide the highest long-term value to customers and other stakeholders.

In 2011, Enersource's E&A business unit determined that a condition-based assessment of its key distribution assets was required to plan more effectively. The undertaking has resulted in a quantifiable evaluation of asset conditions and has provided Enersource with another tool to guide the rehabilitation and replacement prioritization.

A formal and comprehensive AMP is important for asset-intensive businesses (primarily physical assets with relatively long lives) such as electricity distribution utilities. The City experienced an extreme growth period several decades ago, development boom of the 1970's, 1980's and 1990's. Developers installed and contributed a significant amount towards electricity distribution assets and dedicated them to Enersource as a condition of their subdivision agreements with the City. These assets have aged considerably and need to be replaced. Even though there are considerable operational and financial constraints, Enersource strategically deploys its workforce and other resources to ensure that overall system performance is maintained at the highest possible level. This is discussed at Exhibit 2 Tab 2 Schedule 2.

E&A Operating Costs

Overall, E&A has had a net decrease of two positions since 2008, as shown in Table 1 below.

Table 1: Enersource Executive and Administration Number of Employees by Year and Type

Business Unit	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Non-Union	10	11	9	9	8	8
Ending Headcount	10	11	9	9	8	8

E&A converted a Vice President, Information Technology position to a Director-level position, and transferred the position to ISTS in 2009. A Fleet Supervisor position was also transferred to the E&O Division in 2009.

In 2011, a Vice President position was transferred from Enersource to EC's Finance department. In addition, to ensure the implementation and on-going management of the AMP, a new Director of Asset Management and Strategic Projects position was created and filled in 2011.

Enersource's E&A business unit does not anticipate the need for any new resources in the 2012 Bridge or 2013 Test Year.

Below in Table 2 are found E&A operating costs from 2008 to 2013.

Table 2: Enersource Executive and Administration Operating Costs by Type and by Year ($000s):

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$ 1,592	$ 1,741	$ 1,851	$ 1,112	$ 976	$ 976	$ 1,048
Benefits	335	338	363	332	374	426	481
Communications, Legal and Travel	161	81	214	238	315	252	171
Total Costs	$ 2,088	$ 2,160	$ 2,428	$ 1,682	$ 1,665	$ 1,654	$ 1,700

E&A costs have decreased overall from 2008 rates to 2013 Test Year by $388, or 19%. The decrease is primarily due to the net decrease in two positions, which equates to a 20% reduction in headcount in E&A. This has been offset somewhat by an increase in salaries and benefits. For example, benefits expenses have increased in the 2013 Test Year costs from 2008 rates by $146, or 43%, despite the reduction in headcount in E&A. This increase in employee benefits is mainly due to pension-related costs (OMERS).

In summary, the decrease in E&A costs year-over-year is attributable to:

- Decrease in overall staff levels (due to transferred employees);
- Increased average compensation levels;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs); and
- New position Director, Asset Management and Strategic Projects filled in 2011.

Shared Services/Corporate Allocation Operating Costs

As discussed in detail at Exhibit 4 Tab 4 Schedule 1, Enersource Corporation ("EC") is the holding company for the EC family of companies. EC provides corporate governance through the Board of Directors ("BoD") and strategic direction through the office of the President and Chief Executive Officer. EC provides administrative and operational services to Enersource Hydro Mississauga Inc. ("Enersource"), through the following departments: Finance, Human Resources, Corporate Relations, Internal Audit and Enterprise Risk, Purchasing, and Legal.

The Finance department supports Enersource with financial and accounting services, rate setting, and financial analysis. The Human Resources department supports Enersource with resource development and workforce sustainment. The strategic focus of Corporate Relations is to develop and enhance Enersource's brand and reputation, consistent with the strategic plan of the organization. Internal Audit and Enterprise Risk manages the ongoing assessment and reporting of all entity risks, including environmental and business continuity risks faced by the corporation, as well as overseeing the Internal Audit function.

EC allocates costs to Enersource and other operating affiliates based on a cost recovery basis only. The current service agreements between EC and all affiliate companies have been provided at Exhibit 4 Tab 4 Schedules 1 to 6.

Beginning in 2009, EC's method of allocating costs was revised to better align with the amount of services being provided to each affiliate based on either budgeted headcount or as a percentage of revenue. The total cost of corporate

services and the percentage allocated to Enersource from 2008 to 2013 are shown at Exhibit 4 Tab 1 Schedule 1 Appendix 2-L.

Enersource uses a fully allocated cost approach for its shared services which is in conformity with the *Affiliate Relationships Code for Electricity Distributors and Transmitters (*"Electricity ARC").

Description of Corporate Services

A description of the following services provided by EC to Enersource is provided in detail at Exhibit 4 Tab 4 Schedule 1:

- EC's Board of Directors;
- CEO Office and Corporate Relations;
- Internal Audit & Enterprise Risk;
- Finance ;
- Human Resources; and
- Purchasing and Legal.

The staffing levels and operating costs for shared services and corporate allocation are identified below.

Table 1: Enersource Corporation Employee Count by Year and Type

Employee Type	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside (Union)	16	16	16	15	15	15
Non-Union	34	37	36	38	37	37
Total	**50**	**53**	**52**	**53**	**52**	**52**

Overall, EC staff has experienced a net increase of two positions since 2008. EC transferred its Health and Safety staff and one Finance application specialist to Enersource.

As discussed at Exhibit 4 Tab 4 Schedule 1, Finance added two non-union staff members to ensure on-going compliance with IFRS. In 2011, a Vice President position was transferred from Enersource to EC, in Finance. In addition, to ensure EC continually meets ISO 14001 environmental standards, a new non-union Risk Advisor staff member was hired in 2010. In 2008, the Internal Auditor non-union position was converted from a contract position to a permanent position.

EC also added two non-union Corporate Relations staff members that were offset by a reduction of two other non-union staff: a staff lawyer in late 2007 and one executive assistant position at the end of 2011.

EC does not anticipate the need for any new resources in the 2012 Bridge Year or 2013 Test Year.

The operating costs for Enersource Corporation are identified in Table 2 below. Table 3 is a summary version of Appendix 2-L, and identifies the corporate costs allocated to the utility up to and including the 2013 Test Year.

Table 2: EC Operating Costs by Type and by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salary	$ 4,058	$3,970	$4,532	$ 4,475	$ 4,065	$ 4,316	$ 4,554
Benefits	1,484	1,450	1,419	1,767	1,977	1,931	2,084
Audit, Banking & Insurance	1,709	1,680	1,785	1,709	1,714	1,578	1,917
Communications & Customer Relations	227	239	328	338	621	423	419
Employee Development	317	396	232	232	213	243	244
Memberships & Subscriptions	164	140	160	131	134	130	133
Safety Related Costs	363	209	240	255	-	-	-
Supplies, Conferences, Travel	164	111	70	109	77	126	130
Directors Honoraria	186	132	132	132	141	138	140
Social Responsibility	55	99	76	89	102	105	105
Corporate overhead	1,297	981	815	1,101	1,099	1,514	1,583
Legal	130	570	391	503	254	345	335
IFRS Deferral	-	-	(491)	(608)	(391)	-	-
Total Operating Costs	**$10,154**	**$9,977**	**$9,689**	**$10,233**	**$10,006**	**$10,849**	**$11,644**

Table 3: EC Operating Costs Allocated to Enersource per Appendix 2-L ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Total EC Operating Costs, per Table 2	10,154	9,977	9,689	10,233	10,006	10,849	11,644
Allocated to Enersource per App 2-L	8,546	8,358	8,842	9,721	9,506	10,131	10,874

EC costs shown in Table 2 have increased overall from 2008 rates to 2013 Test Year by $1,490. The increase is primarily due to an increase in salaries and benefits combined with increases in communications and customer relations.

Salary costs have increased by $496, or 12%, and account for 33% of the total increase in EC costs from 2008 rates. This increase includes costs for new corporate initiatives such as the transition to IFRS and the net increase of two positions, reflecting the Corporation's focus on customer service and collections.

Benefits expenses have increased by $600, or 40%, and account for 40% of the increase in EC 2013 Test Year costs from 2008 rates. This increase in employee benefits is mainly due to pension-related costs (OMERS).

The reduction in safety-related costs is due to the transfer of the Health, Safety and Security business unit from EC to Enersource in 2011.

Legal expenses have increased by $205, or 158%, and account for 14% of the increase in EC costs from 2008 rates.

Communications and customer relations expenses amount to $192 or 13% of the increase in EC 2013 Test Year costs from 2008 rates. This cost increase is due to corporate rebranding in 2011 and ongoing efforts to promote the corporate image, to educate consumers, and to improve customer service via the provision of self-service functionality on the Enersource website.

In summary, the increase in costs is attributable to:

- Increased staff levels (due to ongoing ISO 14001, and IFRS compliance costs);
- Increased average compensation levels;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs);
- Increase in audit (IFRS), banking, and insurance fees (EC received a one-time reciprocal reduction in 2012);
- IFRS transition costs were deferred between 2009-2011;
- Transferred employees from Enersource to EC (application specialist and one VP position);
- Increase in corporate overhead expenses relating to facilities, ISTS, and asset usage charges from Enersource.

Information Solutions and Technology Services Operating Costs

Enersource's ISTS Strategic Plan

Enersource has developed a comprehensive Information Solutions and Technology Services ("ISTS") strategic plan with a focus on adopting innovative information system solutions that will improve operational flexibility and system reliability, and position Enersource for the future. The strategy is aligned with Enersource's corporate strategic plan of business engagement, external engagement, and organizational engagement. The strategy ensures that Enersource's information technology ("IT") infrastructure is aligned to meet corporate and/or legislative requirements for International Financial Reporting Standards ("IFRS"), the Asset Management Plan ("AMP"), the Green Energy Act ("GEA"), and smart grid initiatives.

In particular, the ISTS strategic plan supports the need for increasingly sophisticated assessment and management of Enersource's distribution system assets which, starting within the next four to five years, will be undergoing significant replacements and/or refurbishments. This is discussed further in Exhibit 2 Tab 2 Schedule 2.

ISTS Operations

The ISTS division is comprised of four business units that oversee IT infrastructure, corporate applications, voice and data services, and the Customer Information System ("CIS").

The ISTS division is comprised of the following four business units:

1. Engineering and Asset Systems;

2. Corporate Records and Mapping;
3. Information Resources; and
4. Information Technology.

For the purpose of this evidence, Information Resources and Information Technology will be considered as one business unit: Information Technology ("IT").

Engineering and Asset Systems ("E&AS")

The functions of E&AS department are particularly critical in monitoring the condition of distribution system assets.

E&AS provides information technology tools to assist Enersource personnel in managing field assets throughout the life cycle. These tools include software and hardware for Engineering and Operations ("E&O"). EA&S provides training, support, and development for the three major engineering systems:

- the Automated Mapping/Facilities Management/Geographic Information System ("AM/FM/GIS"), which is utilized by E&O and Finance staff;
- the Control Room Integrated Operating Model ("IOM"); and
- Smart Plant Foundation ("SPF"), which is Enersource's engineering document management solution.

Additionally, several smaller applications, including Computer-Aided Drafting ("CAD") and thematic mapping software are supported by E&AS. In total, the E&AS department interfaces with multiple software vendors to ensure maintenance contracts are in place for all required engineering applications. The

department also supports specialized equipment such as wide-format plotters, engineering workstations, and rugged lap-tops for field crews.

Corporate Records and Mapping ("CR&M")

The CR&M department is responsible for the creation and maintenance of information in the AM/FM/GIS system. This computer system maps the location, and provides characteristics for over 950,000 plant and equipment items. The department also maintains other electronic systems related to equipment and drawings, and provides security and access to 47,000 electronic and 700,000 microfiched documents. CR&M also provides drafting services, management of easement records, and processes utility and street lighting requests from the City of Mississauga in conjunction with the Public Utilities Coordinating Committee. Enersource continues to emphasize the importance of engineering records. The quality, accuracy, and completeness of this information have greatly contributed to Enersource's efficiency, reliability, and safety.

Information Technology ("IT")

The IT department ensures that information technology assets that are required or planned to be acquired are available and well-managed to meet Enersource's business needs. The department is responsible for supporting Enersource's entire computer infrastructure, including networks, all non-E&O personal computers and servers, and telephone technology. The IT department provides computer operations, data storage, security, application support, application development, and business continuity services. The department supports the Customer Information System ("CIS" also known as Customer Care and Billing or "CC&B") and the financial system. This includes:

- All hardware:

- two AS 400 mini computers;
- four AIX IBM systems housing ten CC&B and related systems;
- approximately 280 desk top and lap top computers;
- approximately 130 virtual or physical servers; and
- associated peripherals such as printers, monitors and telecommunications devices.

- All software:

  - Microsoft applications (including e-mail);
  - financial systems: JD Edwards ("JDE"), which includes the modules Work Management, Fixed Assets, Purchasing, Warehousing, Inventory Management, Financial Reporting, Human Resources, Time Entry, and Accounts Payable;
  - CIS: CC&B, including interfaces with the "hub and spoke" for electronic business transactions ("EBT") with retailers, wholesale settlement, retail settlement, and interfaces to smart metering systems and the IESO in support of time-of-use ("TOU") billing;
  - data security (e.g., backup systems and routines) and system security;
  - intranet and external internet web sites;
  - business continuity products and systems;
  - all other applications;
  - telecommunications systems; and
  - physical security.

- Other devices such as:

  - hand held units (e.g., personal digital assistants ("PDA") for service order communications in the field, "Blackberries");
  - phone system in the buildings;

- all home-based personal computer applications; and
- 'patch' management that ensures that data is adequately protected.

The IT department is responsible for ensuring the Enterprise Resource Planning "ERP" system is available to the Operations, Finance, Purchasing, and Stores departments to manage effectively and efficiently costs, project work orders, and financial reporting requirements. The department also manages all modifications and changes to the ERP system to accommodate and meet all regulatory or legislative requirements. Additionally, the department is responsible for managing the integration of Enersource's internal smart metering system, CIS and the interface with the provincial Meter Data Management and Repository ("MDM/R").

Major Projects

The ISTS division plans, organizes, and coordinates all information system activities to ensure the development and implementation of new or revised processes meet Enersource's standards and end-user requirements.

The ISTS division has initiated several major projects and has implemented several innovative information system solutions over the last few years with a goal of improving efficiency, complying with regulatory changes, improving reliability, reducing costs, and enhancing the safety of outside staff, customers, and the public within the City of Mississauga.

The major projects included the implementation of CC&B, the upgrade of JDE, the implementation of a new electrical distribution operations system (i.e., the IOM), the implementation of TOU billing and integration with the MDM/R, as well as all required hardware and software upgrades. The division continues to move

towards complete virtualization of all servers, and will upgrade obsolete or over-utilized hardware as required.

IOM

The ISTS division's largest project, the IOM, was initiated in 2008 and installed in Enersource's System Control Centre "(SCC"). The long-term goal of the IOM installation is to establish a strategic, centralized connection point for operators and engineers to monitor and operate the distribution system. Automatic monitoring from the IOM has been accomplished, and the next phase is to add the automatic control function.

The IOM integrates AM/FM/GIS, Supervisory Control and Data Acquisition ("SCADA"), and other electronic and manual systems in order to streamline processes. This integration has improved the safety of Enersource's crews, the productivity of the E&O teams, and the reliability of the electrical system. The IOM has eliminated duplicate record-keeping processes, reduced manual paperwork and reporting in the field, and provided automatic reporting of reliability indices. Additionally, Enersource has fully automated the tracking of customer interruption information which provides a detailed audit trail for improved network analysis and maintenance. GPS technology and software were also installed to allow the System Control Operators ("SCO") to be able to see Enersource's actual fleet locations via the IOM system. This improved communication between the SCC and the field allows for more streamlined crew assignment as well as further reliability and productivity enhancements.

CIS

A new CIS was implemented in order to obtain a high level of vendor support and to ensure the future flexibility of the system. The new CIS incorporates improved technology, as well as complex billing, wholesale settlement functionality, and integration with the MDM/R.

A “smart meter” is an electrical meter that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing purposes. Enersource’s “Smart Meter System” is now integrated with the CIS. Enhancements to the CIS systems are being undertaken, which include CC&B production improvements for application and interfaces, customer-centric reporting, and the implementation of TOU billing.

JDE Upgrade and Modifications

Another major project undertaken by the ISTS division was the upgrade of JDE applications. The upgrade enhanced the functionality of the system and improved Enersource’s capabilities in job-cost estimating, and the management of distribution system capital assets.

JDE was also modified to accommodate mandatory IFRS accounting standards. This project began in the second half of 2010 and was completed in October, 2011. This modification required the integration of the AM/FM/GIS application with JDE to facilitate accurate asset derecognition.

Other Projects

To ensure that all computer hardware is kept current, Enersource refurbishes or replaces components every three or four years depending on the type of

hardware installed. Workstations, monitors, servers, and field lap-tops have been replaced in order to bring the equipment up to current standards.

On the infrastructure side, the major initiative was the installation of a corporate "middleware" layer that serves as a common data transfer interface between all disparate computer systems. Another project was the enhancement of IT controls for change, development, and security management.

During 2011, the major technology initiatives were workflow automation for operational efficiency, and security and network upgrades.

Reliability

One of the main goals of Enersource is to improve its reliability performance. Improving reliability is challenging due to the aging electricity infrastructure, i.e., cable, poles, sub-stations, transformers, etc. Enersource's historical computer systems had limitations, requiring a significant amount of manual monitoring of the physical electricity system. This manual monitoring typically assessed performance of assets after problems such as outages arose. This was reactive behaviour, and resulted in limitations on predicting and preventing system failures and outages.

The efforts and projects of ISTS in particular improve Enersource's predictive capabilities. Specifically, the improvements to automatic system monitoring via the IOM, allow Enersource to collect data over the medium and long terms, establish trends, and identify root causes of failures. These results inform Enersource in advance of possible patterns and problems, and hence become predictive tools as opposed to reactive tools.

The current IOM still functions somewhat reactively, but improvements to its functionality both in the recent past and planned for the future, will permit

Enersource to utilize the data being collected and analyzed, and enhance its ability to predict asset performance in the future. As a result, Enersource's accuracy in modelling outage potentials and effects on customers will improve, and in turn will help mitigate future outages through preventative measures, and will maintain or improve reliability to the standards expected by customers and which are expected to be codified by the Board.

The enhanced computer systems such as IOM also allow Enersource to respond much more quickly than it has been able to do in the past to outages and to resolving them, as locations, numbers of customers, and causes are more quickly identified by these automatic systems. Again, this improves Enersource's reliability by reducing the length of outages.

ISTS Operating Costs

In 2012 and 2013 the ISTS division will focus on enhanced internal client service, higher computerized system performance, and business-driven strategic capital investments.

Below in Table 1 are found ISTS Operating Costs and Recoveries. Note that this table does not include asset management costs or new facility costs.

Table 1: Operating Costs and Recoveries: ISTS ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$2,895	$2,119	$2,500	$2,877	$2,739	$3,431	$3,831
Benefits	806	756	745	922	1,335	1,423	1,629
Hardware/Software maintenance	632	553	678	767	790	858	873
Mainframe support	600	430	452	635	549	770	830
Software license renewal	370	280	330	520	379	607	655
Consultants (Prof Services)	287	221	210	184	353	385	361
Communications	188	332	356	268	322	316	316
Other	206	209	234	267	280	326	312
ISTS services provided to affiliates	(527)	(423)	(534)	(578)	(468)	(557)	(580)
Total	**$5,457**	**$4,477**	**$4,971**	**$5,862**	**$6,279**	**$7,559**	**$8,227**

ISTS costs have increased overall from 2008 rates to 2013 Test Year by $2,770. The increase is primarily due to an increase in salaries and benefits combined with significant increases in hardware and software maintenance fees, mainframe support costs, and software license renewal fees.

Salary costs account for $936 or 34% of the total increase in ISTS costs from 2008 rates. This increase includes costs for new corporate initiatives and the net transfer of three positions from other divisions within the organization. In the 2013 Test Year, the division is adding three new positions that relate to Enersource's customer self-service initiative (via Enersource's internet site) and low income account management initiative. These three positions are comprised of an internet developer, a network technician, and an Oracle BI developer - Credit & Collections. Excluding the costs related to the net transfer of the three positions and the costs associated with the above two initiatives, salary costs in this division have increased by 16% since 2008 (or 24% including initiative salary costs).

Benefits expenses amount to $823 or 30% of the increase in ISTS 2013 Test Year costs from 2008 rates. This increase in employee benefits is mainly due to pension related costs (OMERS).

The increases due to hardware/software maintenance, mainframe support costs, and software license renewal fees account for $756 or 27% of the increase in ISTS costs from 2008 rates.

Enersource's IOM system was deployed in the third quarter of 2008. Annual licenses and maintenance services for the IOM system are provided by Intergraph Corporation. Increases in these costs result from the addition of modules to the system and changes in the number of licenses required by Enersource. Annual fees have increased by 89% since 2008 due the addition of five new modules and an increase in the quantity of licenses during 2010. Further enhancements to the system are planned for 2012.

Since 2008, the ISTS division has improved the organization's IT security which is also aligned with the organization's Business Continuity Management ("BCM") plan. This division has also conducted a complete security assessment, penetration test, and scanned for vulnerabilities which resulted in a move from "Intrusion Detection" to "Intrusion Prevention" services. Intrusion Prevention is the de facto standard for providing real-time threat awareness and protection.

An Intrusion Prevention System ("IPS") can detect, notify and prevent attacks in real-time. Older, Intrusion Detection Systems ("IDS") technology alerted organizations to attack attempts or intrusions. However, an IDS relies on administrative intervention to analyze and process the threats. Today, IPS utilizes in-line protection within the data path to not only detect and give notice of attacks, but also to prevent them in real-time. These advancements in the IT security infrastructure have resulted in an increase in maintenance costs since 2008. Security services are provided by Net Cyclops Inc. and include hardware, software, maintenance, and licenses fees.

Mainframe support services are provided primarily by Oracle Corporation ("Oracle"). The increase in mainframe costs is attributable to:

- The addition of JDE modules during 2012 and 2013;
- Oracle CC&B support costs: these are ongoing maintenance costs for the CC&B application. This system comprises billing, customer contacts and customer care, collections, meter reading, retail settlement, TOU billing, interfaces to the Independent Electricity System Operator, and EBT transactions with retailers. This system went live in October, 2009 and the ongoing maintenance costs started fully in 2010;
- Oracle LOADSTAR Profile & Settlement System ("LPSS") maintenance: this is the ongoing maintenance cost for Enersource's energy data management system (LPSS). The LPSS system is part of the end-to-end "Meter to Cash" process and manages the data for Enersource's largest customers as well as wholesale settlement and the calculation of the Net System Load Shape. This system also went live in October, 2009;
- Oracle database maintenance which increased as a result of the JDE upgrade in 2011;
- Oracle Business Intelligence ("BI") maintenance: these are ongoing maintenance costs for the Oracle BI application. This system will support management decision-making, starting with the Collections module of CC&B;
- User Productivity Kit ("UPK"): these are the ongoing maintenance costs for the UPK modules. UPK is a system used to produce training materials and was upgraded in association with the JDE upgrade.

Mainframe support costs have also increased due to Enersource's ongoing support agreement with Systemgroup Consulting Inc., the vendor that developed Enersource's middleware software. Middleware is used as part of the interface solutions for CC&B and JDE, and ensures that the interfaces are robust and secure. The agreement was put in place after CC&B went live.

The increase in software license renewal costs is attributable to the following applications which have been added or modified since 2008:

- Dynamic Systems Inc.: handheld scanning for inventory picking; software license maintenance/support;
- Elster Solutions: software license activation/maintenance for smart meters related to the implementation of TOU billing;
- Hewlett Packard Quality Center: license maintenance fees for quality control software;
- InsightSoftware.com: general ledger inquiry reporting software maintenance;
- Nintex USA LLC: automation of workflows via SharePoint (collaboration software) for various requirements throughout Enersource; and
- VMWare, Inc.: maintenance on virtualization software that has been put in place to improve capacity management, security, and redundancy.

Services Provided to Affiliates

Enersource owns, operates, and maintains the information and computer systems used by Enersource and its affiliates (e.g., use of computers, access to mainframe time, telecommunications, and software). The CIS is used exclusively by Enersource, and Enersource's affiliates do not have access to the CIS or the information it houses. The associated ISTS expenses are incurred by Enersource and are charged to all other active companies, within the Enersource family of companies. This treatment is consistent with the *Affiliate Relationships Code for Electricity Distributors and Transmitters (*"Electricity ARC"), and is reflected in the service agreements between Enersource and its affiliates, as found at Exhibit 4 Tab 4 Schedules 1 to 6.

Enersource forecasts that it will recover $580 in the 2013 Test Year through the ISTS recovery rate. The corresponding amount for the 2012 Bridge Year is $557 (indicated in Table 1 above).

Information technology actual costs are allocated to affiliates based on actual relative monthly headcount figures.

Table 2: ISTS Employee Count by Year and Type

Employee Type	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside	12	11	11	11	11	11
Non-Union	27	27	30	32	35	38
Total	**39**	**38**	**41**	**43**	**46**	**49**

Overall, ISTS has seen a net increase of ten positions since 2008. This is comprised of seven new positions which were added to improve quality

processes in the division and to provide development and support services to the user community, including the customer self-service initiative and the low income account management initiative, described above.

Due to corporate re-organizations, there was a net transfer of three positions from other divisions within Enersource to the ISTS division. The Vice President, Information Technology position formerly in Enersource Administration was converted to a Director position, and transferred to ISTS in 2009. The Customer Service division transferred two non-union positions to ISTS on January 1, 2012 in order to centralize CC&B computer operations and data analyst functions. The Finance and E&O divisions also transferred one non-union position each to ISTS to provide expertise to the ISTS division in order to understand better the requirements of these key divisions. During 2008, the ISTS division included the Facilities department. In 2009, the Facilities department was realigned into the E&O division and two non-union positions were transferred from ISTS to E&O.

In summary, the increase in costs is attributable to:

- Increased average compensation levels;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs);
- Increased staff levels due to corporate re-structuring and new customer-focused initiatives; and
- Increased hardware/software maintenance fees, mainframe support costs, and software license renewal fees.

Regulatory Affairs Operating Costs

Enersource's corporate strategy stresses the need for strong stakeholder relations. Key industry stakeholders include customers, intervenors, the Ontario Energy Board ("OEB"), the Independent Electricity System Operator ("IESO"), the Ontario Power Authority ("OPA"), and the Ministry of Energy. Enersource's Regulatory Affairs ("RA") department is a primary liaison with these key external stakeholders, except customers. The RA department oversees the company's regulatory strategy, manages Enersource's application processes, and advocates Enersource's regulatory positions, including providing input on OEB policy.

The RA department is Enersource's main contact with the OEB, the IESO and other agencies on all regulatory matters and is the main repository for regulatory records and documentation. In consultation with various stakeholders, RA develops Enersource's positions on defined issues, prepares regulatory filings (including those related to smart meters, Time-of-Use or "TOU", and Electricity Service Quality Requirements, or "ESQRs"), and rate applications, and makes submissions in regulatory consultations and other proceedings.

The major expenses included in RA's operating costs for the 2013 Test Year are the OEB's cost assessment, intervenor cost awards and annual fees to the Electrical Safety Authority ("ESA").

Table 1 below provides a summary of the number and type of employees within RA from 2008 to 2013.

Table 1: Regulatory Affairs Employee Count by Year and Type

Business Unit	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Non-Union	-	-	2	3	3	3
Regulatory Affairs Headcount	-	-	2	3	3	3

Two non-union staff were transferred from the Customer Care business unit to a new Regulatory Affairs business unit in 2010. An executive assistant position in the Executive and Administration ("E&A") business unit was also transferred and converted to an RA coordinator position in 2011.

Table 2 below provides a summary of the annual operating costs within RA between 2008 and 2013. The costs associated with the 2013 cost of service application are not included in Table 2 but are shown separately in Table 3.

Table 2: Regulatory Affairs Operating Costs by Type and by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$ -	$ -	$ -	$ 232	$ 276	$ 303	$ 315
Benefits	-	-	-	61	100	123	131
Conferences	-	-	-	9	3	12	12
Publications of Notices	-	-	-	2	19	42	33
Intervenor and Legal Costs	146	17	154	59	78	75	75
ESA Costs	88	93	94	93	96	98	98
OEB Assessed Costs	840	788	805	759	768	820	854
Total Costs	$ 1,074	$ 898	$ 1,053	$ 1,215	$ 1,340	$ 1,473	$ 1,518

The operating costs such as salaries, benefits, and communication costs associated with RA were included in Customer Care until 2009. Beginning in 2010, the operating costs were transferred to a new RA business unit to better manage and align how Enersource incurs regulatory costs.

The annual variances in operating costs are attributable to:

- The transfer of two employees in 2010 and one employee in 2011;
- Increased average compensation levels;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs);
- Decrease in annual intervenor and legal costs from 2008 (a year which included a cost of service proceeding and significant associated costs); and
- Increases in ESA and OEB assessments.

The RA department also anticipates that it will incur a significant amount of expenses relating to this Application. These additional regulatory costs are shown in Table 3 below, and include OEB cost assessments and associated expenses such as legal fees, consultant fees, and intervenor cost awards. Enersource believes that these costs should be recovered and amortized over four years to coincide with the expected cost of service period plus IRM term. In the calculation of its 2013 revenue requirement, Enersource has excluded $275 from 2013 Test Year OM&A, but included $163 representing one-quarter of the total one-time regulatory costs.

Table 3: 2013 Cost of Service Application Expenses by Year ($000s)

	2012 Bridge	2013 Test	Total
Intervenor	$ 50	$ 120	$ 170
Legal	125	75	200
OEB Hearing	150	75	225
Consulting Fees	50	5	55
Total 2013 Cost of Service Application Expenses (To Be Recovered Over Four Years)	$ 375	$ 275	**$650**

Facilities Management Services Operating Costs

Facilities Management Services Overview

Enersource's Facilities Management Services ("FMS") division is responsible for the management of Enersource's properties including maintenance services, mechanical services, custodial services, and related projects. This includes regular inspections, maintenance and upgrading of buildings including HVAC (heating, ventilation and air conditioning), mechanical, plumbing and electrical services. This division is also responsible for inventory management and the safety and reliability of Enersource's fleet of vehicles. These costs are incurred to provide a safe, clean, comfortable, and sustainable environment for staff members and visitors. The division is comprised of three departments: Grounds and Building Operations; Fleet Operations; and Warehouse Operations.

Grounds and Building Operations

The Grounds and Building Operations ("G&B") department is responsible for the ongoing day-to-day operations and long-term maintenance of the grounds and building. The department has implemented several energy saving measures in addition to upgrades to the HVAC, plumbing and lighting systems.

The department provides ongoing services for Enersource's facilities, including:

- Routine maintenance;
- Preventive maintenance;
- Office services;
- Housekeeping services;
- Landscaping services;
- Upgrade and renovation of current office spaces; and

- Leasing of any necessary temporary work sites.

Enersource's current head office and operational centre, at 3240 Mavis Road, hosts over 400 employees and contractors. The facility is comprised of three sections aging from 21 to 49 years old. Enersource continues to grow and evolve and the existing facility no longer meets the needs of Enersource. This is explained more fully at Exhibit 2, Tab 2, Schedule 5, "Administration Office and Operations Centre".

Enersource has reviewed options to improve the work environment of its current head office and operational centre by conducting a comprehensive review of internal space allocations to identify potential areas for expansion to accommodate future workforce requirements. Enersource concluded that to maximize customer value, and to meet the needs of employees and other stakeholders, it should pursue the acquisition of a standard office building for an administration office and to return the 3240 Mavis Road property to an operational configuration in keeping with its capabilities and original design intent.. The operating costs associated with the new administration building have been included in the "New Administration Office" discussion at Exhibit 4 Tab 1 Schedule 12.

In addition to the 3240 Mavis Road facility, a property, located at 3456 Mavis Road, has been leased by Enersource since November 2008. The property adjacent to 3240 Mavis Road, and the associated capital cost, was included in Enersource's 2008 rate application. It was planned to be purchased in 2008 but never became available for purchase. This necessitated leasing the 3456 Mavis Road property. The leased property is being used to store and deploy poles and related distribution equipment and inventory. Eventually, office staff will be moved to the new administration building at Derry Road, which will allow

Enersource to move the inventory and equipment to 3240 Mavis Road and end the lease at 3456 Mavis Road.

Fleet Operations

Enersource's Fleet Operations ("Fleet") department is responsible for the management of Enersource's entire fleet of vehicles and associated equipment relied on to carry on distribution system related work and the administration of all fleet-related duties and activities. Enersource's fleet of over 180 items includes light transportation vehicles (cars, trucks, etc.), heavy transport vehicles (cube vans, dump trucks, etc), bucket trucks, trailers, and miscellaneous equipment. Vehicles are maintained to a level that achieves safe performance and complies with all laws and Ontario Ministry of Transportation regulations.

The Fleet department's key objectives include:

- Reducing equipment downtime and improving equipment utilization;
- Procuring cost-efficient fleet support;
- Timely and cost-efficient equipment procurement and disposal;
- Data collection and information management that matches business unit requirements; and
- Maintenance of vehicles in accordance with the Highway Traffic Act.

The primary challenge for the Fleet department is the fluctuation of fuel costs. To mitigate risks associated with fluctuations in fuel costs, Enersource joined a fuel buying co-op with City of Mississauga, Region of Peel, Mississauga Police and Fire Department to obtain volume discounts on fuel pricing.

Future Fleet Developments

Enersource is taking steps to further understand and take advantage of greener technologies within its fleet of service vehicles. This fleet now includes a hybrid bucket truck purchased in 2010, and a new Chevrolet Volt, purchased in 2011. The Chevrolet Volt is a front-wheel-drive, extended-range electric vehicle with a rechargeable energy storage system.

Both vehicles are being evaluated under normal operating conditions to determine if they are suitable to become ongoing additions to fleet replacements. To date, Enersource has had good success with the hybrid bucket truck. The unit is quiet, saves on fuel, has operated very reliably, and eliminates engine emissions when operating on battery power. The Chevrolet Volt is a very recent addition to the fleet and is still currently being evaluated.

With the fostering of a culture of conservation, and the potential increase in the number of electric vehicles in the future, Enersource must understand the impact that electric vehicles can have on the electrical grid. Enersource will conduct studies to determine which steps the company may need to take in the future to prepare for the possible increased use of consumer electric vehicles. These studies will include monitoring the various impacts on electrical demand and consumption as well as any related utility operating implications. The Chevrolet Volt will assist with this endeavour.

Warehouse Operations (Stores)

Enersource's Warehouse Operations ("Stores") department operates the warehouse and provides Enersource crews with materials, tools, and services that are necessary to build and maintain the distribution system. The department distributes materials, tools, and personal protective equipment to support operation and maintenance programs. The department works closely with other

business units within the Engineering and Operations ("E&O") division for material approval and compliance with Electrical Safety Authority ("ESA") regulations.

The department is responsible for repairing, maintaining, and testing tools to ensure they are safe for use. They also manage the inventory and assist the Purchasing department in optimizing inventory size in order to minimize handling costs. In addition, the department stores and disposes waste materials including, but not limited to, general waste, soil, asphalt, concrete, recyclable materials, transformer oil, and PCB-contaminated oil.

The Stores department's key objectives include:

- Receipt of inventory and distribution of materials, tools and supplies;
- Maintenance of inventory in a cost effective and efficient manner;
- Inspection, testing and repairing of tools and materials to ensure they are in good working condition;
- Performing material cycle counts and maintenance of low variances for inventory; and
- Safe disposal of waste materials.

In an effort to reduce waste and chemical disposal costs, Enersource began to segregate waste (soil, asphalt, concrete, etc) before disposal. Waste disposal companies charged an extra cost to segregate the waste collected from Enersource. This initiative has reduced waste and chemical disposal costs by 18% compared to 2008 Rates.

FMS Operating Cost Summary

Overall, the FMS division has had a net increase of two positions since 2008 with the addition of an Equipment Maintainer/Storekeeper in the Stores department and

the transfer of one union staff member from the Substations department during 2009.

The number of employees within FMS, by year and by type, are shown in Table 1 below.

Table 1: Facilities Management Services Number of Employees by Year and Type

Business Unit	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside	1	1	1	1	1	1
Outside	13	16	16	15	15	16
Total	**14**	**17**	**17**	**16**	**16**	**16**

Below in Table 2 are found FMS operating costs and recoveries from 2008 to the 2013 Test Year. Note that Table 2 does not include operating costs related to the new administration building, which are discussed and shown separately in Exhibit 4, Tab 1, Schedule 12.

Table 2: Facilities Management Services Operating Costs by Type and by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salaries	$ 826	$ 888	$ 951	$ 964	$ 995	$ 1,058	$ 1,095
Benefits	381	391	425	473	503	545	572
Property Taxes	300	271	271	268	268	280	300
Utilities	605	528	419	458	498	584	583
Facility Maintenance & Repair	611	784	596	425	486	560	569
Rental (3456 Mavis)	-	20	140	155	164	150	150
Fuel Costs	505	589	370	531	499	508	526
Vehicle Maintenance & Repair	436	352	474	407	383	356	373
Insurance & Licensing	145	144	136	112	126	132	138
Small Tools & Safety Wear	330	250	307	258	233	292	298
Waste & Chemical Disposal	250	164	259	226	149	200	205
Other Costs	195	290	372	217	357	266	274
FMS services provided to affiliates	(335)	(338)	(354)	(310)	(335)	(499)	(625)
Recoveries	(2,761)	(2,955)	(3,209)	(3,373)	(3,335)	(3,012)	(3,081)
Accounting IFRS Change – Overhead Burdens	-	-	-	-	483	502	513
Total Costs	**$ 1,488**	**$ 1,378**	**$1,157**	**$ 811**	**$ 1,474**	**$ 1,922**	**$ 1,890**

FMS operating costs have increased overall from 2008 rates to 2013 Test Year by $402, or 27%. The increase is primarily due to an increase in salaries and benefits combined with increases in rental costs and significant increases due to the conversion to IFRS.

Salary costs have increased by $269, or 33%, and account for 67% of the total increase in FMS costs from 2008 rates.

Benefits expenses have increased by $191, or 50%, and account for 48% of the increase in FMS 2013 Test Year costs from 2008 rates. This increase in employee benefits is mainly due to pension-related costs (OMERS).

Increased costs related to the accounting changes due to the conversion to IFRS are discussed below.

Change in Capitalization Policy

IFRS prescribes which cost can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP are not allowed under IFRS. These costs, referred to as overhead burdens, have resulted in an increase in Enersource's operating costs. FMS costs have increased by $513 in the 2013 Test Year compared to 2008 rates due to these overhead burdens. Please refer to Exhibit 2 Tab 1 Schedule 1 for further details on the change in capitalization policy.

FMS Services provided to Affiliates

Enersource owns, operates, and maintains all offices used by Enersource and its affiliates.. The associated expenses are incurred by Enersource and are charged to all other active companies, within the Enersource family of companies based on headcount. This treatment is consistent with the Board's *Affiliate Relationships Code for Electricity Distributors and Transmitters* ("ARC") and is reflected in the service agreements (Exhibit 4 Tab 4 Schedules 1 to 6) between Enersource and its affiliates.

FMS will recover $625 in the 2013 Test Year from affiliates. This is $290, or 87%, higher that the amount in 2008 rates, as shown in Table 2 above.

In summary, the increase in FMS operating costs is attributable to:

- Increased average compensation levels;
- Increased number of positions in the division;

- A change in Enersource's capitalization policy;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs); and
- Facility rental costs (at 3456 Mavis Road).

New Administration Office Operating Costs

Enersource developed a flexible and executable strategic facilities plan that addressed the specific facilities needs of the organization and which is aligned with the key components of the corporate strategic plan of business engagement, external engagement, and organizational engagement. Details found in Exhibit 2 Tab 2 Schedule 5 explain the analysis used to explore the range of options available to Enersource, the criteria used to analyze the organization's facility needs, and the facility plan that was implemented to meet the long-range needs of the Company.

The plan culminated with the acquisition of a new building at 2185 Derry Road West ("Derry Road") that will serve as the new administration office for Enersource. The 3240 Mavis Road property will be reconfigured to its originally-intended use as an operations centre.

Enersource engaged the real estate advisory services of Avison Young Commercial Real Estate (Ontario) Inc. ("Avison Young") which assisted with project management, development of the strategic facilities plan, request for proposal ("RFP") administration, real estate research, and furniture and fixture relocation management.

Enersource had reviewed options to improve the work environment of its current head office and operational centre at 3240 Mavis Road. Internal space allocations were assessed to identify potential areas for expansion to accommodate future workforce requirements while minimizing any costs associated with reconfiguring floor plans. Several alternative options were also considered including the purchase of a new or existing facility, and the purchase of land to construct a new building. After a detailed review of all options to allow

for a flexible work area and a safe work environment, Enersource decided to purchase an existing building at Derry Road.

The new administration office on Derry Road meets Enersource's requirements of improving efficiencies and staff working conditions, meeting future staffing requirements and growth needs. The need for expansion came from all parts of the business, including fleet, Stores, staffing increases, and support facilities.

The incremental staff required to support the new administration office are shown in Table 1. Table 2 provides the employee type for the three incremental staff.

The acquisition of a second building and the separation of staff will necessitate Information Systems and Technology Services ("ISTS") support in both buildings. A network technician will be located at the new administration office to provide primary help desk support.

A maintenance caretaker will be added to operate and maintain building infrastructure and to provide service for staff. The caretaker will be able to respond efficiently to building emergencies and to staff issues.

A facilities analyst will operate, maintain, and install the building automation system ("BAS"). The BAS will allow the centralization of key building functions such as energy load controls, lighting, electrical panels, HVAC[1], fire alarm panels, building generator, closed-circuit television, and building access controls. This dedicated Enersource resource will provide tools to facilities and security staff to operate the building efficiently, and allow faster response to building emergencies such as fire, generator or electrical disturbances.

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[1] Heating, ventilation, and air conditioning.

Table 1: New Administration Office Number of Employees by Year

New Administration Building	2012 Bridge	2013 Test
Facilities analyst	1	1
Network technician	1	1
Maintenance caretaker	1	1
Ending headcount	**3**	**3**

Table: New Administration Office Type of Employee by Year

New Administration Building	2012 Bridge	2013 Test
Outside	1	1
Non-Union	2	2

The three new positions have been included in the 2012 Bridge Year. No additional positions were added for the 2013 Test Year.

Table 3: New Administration Office Operating Costs by Type and by Year ($000s)

	2012 Bridge	2013 Test
Salaries	$ 93	$ 225
Benefits	40	86
Facility maintenance & repair	339	757
Property taxes	165	250
Utilities	210	350
Total Costs	$ 847	$ 1,668

The 2013 Test Year includes $1,668 of operating expenses for the new administration office. These operating costs include salary and benefit

expenses, facility maintenance and repair costs, property taxes, and utilities. As mentioned, Enersource has included three new positions in the 2012 Bridge Year due to the addition of the facility.

Enersource administrative staff at 3240 Mavis Road are expected to transfer to the new administration office during the third quarter of 2012. Facilities personnel and contractors are expected to begin any maintenance and repair work required in the second quarter of 2012. Operating costs in 2012 have been prorated based on expected occupancy in the building.

Other Operating Costs

Enersource will incur other operating expenses not directly attributable or allocated to a division. More specifically, Enersource has operating costs associated with retailers, bond rating agencies, environmental testing and site remediation, and a corporate incentive plan.

Retail Transaction Services

Enersource incurs costs associated with managing retailer transactions. These costs have no impact on rates. Retail transaction costs are forecast as a pass-through cost since there is an offsetting amount included in other revenue. Retail transaction costs are included in the total other expenses in Table 1 below, but they are offset by the matching revenue shown at Table 1 of Exhibit 3 Tab 3 Schedule 1.

Retail transaction costs have declined between 2008 and 2013. As discussed in Exhibit 3 Tab 3 Schedule 1, this trend is due to a reduction of customers that have chosen to procure electricity from a licensed retailer, and the corresponding reduction in transaction activity.

Environmental Rehabilitation Costs

Environmental assessments, which Enersource began in 2006, are conducted on Enersource-owned assets and properties. The existing administration office and operations centre at 3240 Mavis Road as well as 33 of 66 substations have already been assessed or await a final environmental report. Currently, remediation is required at two substation properties.

A long term environmental management system ("EMS") was developed in 2010. Since then, Enersource has met the ISO 14001 standards in each annual audit.

These standards require a supporting policy manual, including procedures, occurrence data collection forms, and training programs.

Enersource has included the effect and costs of the environmental risk assessments, such as removing underground storage tanks and soil remediation, in Table 1. Enersource has forecast $103 for work to be carried out in the 2013 Test Year. The variances created year over year in these expenses relate to the difference in year-end estimates or provisions and the actual costs incurred the following year.

Enersource's Incentive Plan

Enersource will continue its incentive compensation plan during the 2013 Test Year. The incentive compensation plan is based on the following performance measures:

- Reliability;
- Safety;
- Electricity Service Quality Requirements; and
- Enersource Net Income (Shareholder Funded).

The incentive plan is also discussed at Exhibit 4 Tab 3 Schedule 1.

Below is a chart which summarizes Enersource's other operating expenses from 2008 to 2013.

Table 1: Other Operating Costs by Year ($000s)

Description	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Retailer Services	329	311	303	292	244	207	193
Environmental Testing and Remediation (provision and expense)	200	(148)	672	(88)	20	100	103
Incentive Plan, Bond Rating Agencies ' Charges, and other Corporate Expenses	1,665	1,604	1,706	1,530	1,173	1,569	1,608
Total Other Expenses	**$2,194**	**$1,767**	**$2,681**	**$1,734**	**$1,437**	**$1,876**	**$1,904**

(1) Total includes Retailer Services costs.

Appendix 2-D
Accounts for OM&A Analysis

Distribution Expenses - Operations

Account	***Description***
5005	Operation Supervision and Engineering
5010	Load Dispatching
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment - Operation Labour
5015	Transformer Station Equipment - Operation Supplies and Expenses
5016	Distribution Station Equipment - Operation Labour
5017	Distribution Station Equipment - Operation Supplies and Expenses
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses
5030	Overhead Sub-transmission Feeders - Operation
5035	Overhead Distribution Transformers - Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses
5050	Underground Sub-transmission Feeders - Operation
5055	Underground Distribution Transformers - Operation
5060	Street Lighting and Signal System Expense
5065	Meter Expense
5070	Customer Premises - Operation Labour
5075	Customer Premises - Operation Materials and Expenses
5085	Miscellaneous Distribution Expenses
5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5096	Other Rent

Distribution Expenses - Maintenance

Account	***Description***
5105	Maintenance Supervision and Engineering
5110	Maintenance of Buildings and Fixtures - Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5130	Maintenance of Overhead Services
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5155	Maintenance of Underground Services
5160	Maintenance of Line Transformers
5165	Maintenance of Street Lighting and Signal Systems
5170	Sentinel Lights - Labour
5172	Sentinel Lights - Materials and Expenses
5175	Maintenance of Meters
5178	Customer Installations Expenses - Leased Property
5195	Maintenance of Other Installations on Customer Premises

Appendix 2-D
Accounts for OM&A Analysis

Billing and Collecting

Account	*Description*
5305	Supervision
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting - Cash Over and Short
5330	Collection Charges
5335	Bad Debt Expense
5340	Miscellaneous Customer Accounts Expenses

Community Relations (including sales expenses)

Account	*Description*
5405	Supervision
5410	Community Relations - Sundry
5415	Energy Conservation
5420	Community Safety Program
5425	Miscellaneous Customer Service and Informational Expenses
5505	Supervision
5510	Demonstrating and Selling Expense
5515	Advertising Expenses
5520	Miscellaneous Sales Expense

Administrative and General Expenses

Account	*Description*
5605	Executive Salaries and Expenses
5610	Management Salaries and Expenses
5615	General Administrative Salaries and Expenses
5620	Office Supplies and Expenses
5625	Administrative Expense Transferred - Credit
5630	Outside Services Employed
5635	Property Insurance
5640	Injuries and Damages
5645	Employee Pensions and Benefits
5650	Franchise Requirements
5655	Regulatory Expenses
5660	General Advertising Expenses
5665	Miscellaneous General Expenses
5670	Rent
5675	Maintenance of General Plant
5680	Electrical Safety Authority Fees
5685	Independent Electricity System Operator Fees and Penalties
5695	OM&A Contra Account
6205	Donations (Charitable Contributions)

Appendix 2-E
Summary of OM&A Expenses

Applicants should complete the two tables on this page.

Table 1: OM&A Year-over-Year Comparisons

This table should be completed for each of the comparisons outlined below (Note 1)

1 Last rebasing year (LRY) Actuals versus LRY Board approved (shown)
2 Year 1 Actuals versus LRY Actuals (Not necessary if LRY = Year 1)
3 Year 2 Actuals versus Year 1 Actuals
4 Year 3 Actuals versus Year 2 Actuals
5 Bridge Year versus Year 3 Actuals
6 Test Year versus Bridge Year

	2008	2008	Variance	Percentage Change
	Board-approved	Actuals	$	%
Operations	$ 13,339,679	$ 11,702,739	-$ 1,636,940	-12.27%
Maintenance	$ 3,746,644	$ 3,295,253	-$ 451,391	-12.05%
Billing and Collecting	$ 8,422,185	$ 7,325,900	-$ 1,096,285	-13.02%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 15,247,150	$ 13,044,178	-$ 2,202,972	-14.45%
Taxes Other Than Income Taxes	$ 897,400	$ 866,050	-$ 31,350	-3.49%
Total OM&A Expenses	$ 41,653,058	$ 36,234,120	-$ 5,418,938	-13.01%
Inflation Rate				

	2008	2009	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 11,702,739	$ 13,445,543	$ 1,742,804	14.89%
Maintenance	$ 3,295,253	$ 3,487,547	$ 192,294	5.84%
Billing and Collecting	$ 7,325,900	$ 8,126,830	$ 800,930	10.93%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 13,044,178	$ 15,600,037	$ 2,555,859	19.59%
Taxes Other Than Income Taxes	$ 866,050	$ 863,606	-$ 2,444	-0.28%
Total OM&A Expenses	$ 36,234,120	$ 41,523,563	$ 5,289,443	14.60%
Inflation Rate				

	2009	2010	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 13,445,543	$ 14,770,356	$ 1,324,813	9.85%
Maintenance	$ 3,487,547	$ 3,264,481	-$ 223,065	-6.40%
Billing and Collecting	$ 8,126,830	$ 10,799,691	$ 2,672,861	32.89%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 15,600,037	$ 15,896,443	$ 296,406	1.90%
Taxes Other Than Income Taxes	$ 863,606	$ 867,586	$ 3,980	0.46%
Total OM&A Expenses	$ 41,523,563	$ 45,598,558	$ 4,074,995	9.81%
Inflation Rate				

	2010	2011	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 14,770,356	$ 16,040,763	$ 1,270,407	8.60%
Maintenance	$ 3,264,481	$ 3,797,642	$ 533,160	16.33%
Billing and Collecting	$ 10,799,691	$ 11,480,571	$ 680,879	6.30%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 15,896,443	$ 18,599,779	$ 2,703,335	17.01%
Taxes Other Than Income Taxes	$ 867,586	$ 864,465	-$ 3,121	-0.36%
Total OM&A Expenses	$ 45,598,558	$ 50,783,218	$ 5,184,661	11.37%
Inflation Rate				

	2011	2012 Bridge Year	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 16,040,763	$ 16,852,502	$ 811,739	5.06%
Maintenance	$ 3,797,642	$ 4,699,136	$ 901,494	23.74%
Billing and Collecting	$ 11,480,571	$ 11,688,482	$ 207,911	1.81%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 18,599,779	$ 22,693,565	$ 4,093,786	22.01%
Taxes Other Than Income Taxes	$ 864,465	$ 1,075,000	$ 210,535	24.35%
Total OM&A Expenses	$ 50,783,218	$ 57,008,685	$ 6,225,467	12.26%
Inflation Rate				

	2012 Bridge Year	2013 Test Year	Variance	Percentage Change
	Actuals	Forecast	$	%
Operations	$ 16,852,502	$ 17,431,212	$ 578,710	3.43%
Maintenance	$ 4,699,136	$ 5,446,624	$ 747,488	15.91%
Billing and Collecting	$ 11,688,482	$ 11,989,905	$ 301,423	2.58%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 22,693,565	$ 25,031,495	$ 2,337,930	10.30%
Taxes Other Than Income Taxes	$ 1,075,000	$ 1,200,000	$ 125,000	11.63%
Total OM&A Expenses	$ 57,008,685	$ 61,099,236	$ 4,090,551	7.18%
Inflation Rate				

Table 2: Additional Total OM&A Expense Comparative Information Table

Required Total OM&A Comparison

	2011 Actuals	2013 Test Year Forecast	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 50,783,218	$ 61,099,236	$ 10,316,018	20.31%
	2008 Board-approved	**2013 Test Year Forecast**	**Variance $**	**Percentage Change %**
Test Year versus LRY Board-approved	$ 41,653,058	$ 61,099,236	$ 19,446,178	46.69%
Simple average of % variance for all years				11.04%
Compound annual growth rate for all years				0

Note 1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account	Description	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Operations							
5005	Operation Supervision and Engineering	$ 2,069,858	$ 2,238,397	$ 2,022,276	$ 2,047,475	$ 2,276,153	$ 2,528,872
5010	Load Dispatching	$ 1,609,725	$ 2,087,224	$ 2,205,345	$ 2,394,218	$ 2,347,417	$ 2,489,936
5012	Station Buildings and Fixtures Expense	$ -	$ -	$ -	$ -	$ -	$ -
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5016	Distribution Station Equipment - Operation Labour	$ 1,037,193	$ 1,118,027	$ 1,267,573	$ 1,345,721	$ 1,454,928	$ 1,544,169
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 140,982	$ 193,830	$ 139,348	$ 130,012	$ 150,500	$ 166,820
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 643,391	$ 962,371	$ 937,618	$ 1,190,378	$ 1,310,887	$ 1,414,161
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 118,558	$ 259,376	$ 170,141	$ 221,926	$ 301,436	$ 309,967
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5035	Overhead Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 2,307,597	$ 2,906,901	$ 2,999,139	$ 3,330,111	$ 2,963,173	$ 3,211,590
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 225,829	$ 259,017	$ 276,648	$ 350,126	$ 286,880	$ 286,880
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5055	Underground Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -	$ -
5060	Street Lighting and Signal System Expense	$ 14	$ 9	$ -	$ -	$ -	$ -
5065	Meter Expense	$ 741,493	$ 383,175	$ 1,615,195	$ 1,370,747	$ 1,649,800	$ 1,030,569
5070	Customer Premises - Operation Labour	$ 1,503,620	$ 1,586,206	$ 1,449,163	$ 1,605,236	$ 1,562,292	$ 1,629,935
5075	Customer Premises - Operation Materials and Expenses	$ 85,767	$ 103,299	$ 74,083	$ 72,138	$ 87,540	$ 86,540
5085	Miscellaneous Distribution Expenses	$ 1,099,800	$ 1,251,939	$ 1,519,957	$ 1,704,528	$ 2,196,496	$ 2,566,773
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -
5096	Other Rent	$ 118,912	$ 95,772	$ 93,868	$ 278,146	$ 265,000	$ 165,000
Total - Operations		$ 11,702,739	$ 13,445,543	$ 14,770,356	$ 16,040,763	$ 16,852,502	$ 17,431,212

Account	Description	LRY Actual 2008	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Maintenance							
5105	Maintenance Supervision and Engineering	$ -	$ -	$ -	$ -	$ -	$ -
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -	$ -	$ -
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -
5114	Maintenance of Distribution Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -
5120	Maintenance of Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -
5125	Maintenance of Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -
5130	Maintenance of Overhead Services	$ 1,899,797	$ 2,285,880	$ 2,292,131	$ 2,407,930	$ 2,456,053	$ 2,679,514
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 815,164	$ 759,872	$ 779,104	$ 873,263	$ 879,101	$ 965,194
5145	Maintenance of Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -
5150	Maintenance of Underground Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -
5155	Maintenance of Underground Services	$ -	$ -	$ -	$ -	$ -	$ -
5160	Maintenance of Line Transformers	$ -	$ -	$ -	$ -	$ -	$ -
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5175	Maintenance of Meters	$ 580,292	$ 441,795	$ 193,247	$ 516,449	$ 1,363,982	$ 1,801,916
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -
Total - Maintenance		$ 3,295,253	$ 3,487,547	$ 3,264,481	$ 3,797,642	$ 4,699,136	$ 5,446,624
Account	**Description**	**LRY Actual 2008**	**2009 Actuals**	**2010 Actuals**	**2011 Actuals**	**2012 Bridge Year**	**2013 Test Year**
Billing and Collecting							
5305	Supervision	$ 1,000,824	$ 1,188,424	$ 2,171,582	$ 1,595,209	$ 3,669,783	$ 3,842,550
5310	Meter Reading Expense	$ -	$ -	$ -	$ -	$ -	$ -
5315	Customer Billing	$ 4,973,379	$ 5,421,030	$ 5,398,083	$ 5,658,911	$ 4,106,677	$ 4,247,244
5320	Collecting	$ -	$ -	$ -	$ -	$ -	$ -
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -	$ -	$ -
5330	Collection Charges	$ -	$ -	$ -	$ -	$ -	$ -
5335	Bad Debt Expense	$ 1,270,475	$ 1,252,636	$ 2,801,922	$ 3,706,065	$ 3,600,000	$ 3,550,000
5340	Miscellaneous Customer Accounts Expenses	$ 81,223	$ 264,741	$ 428,103	$ 520,385	$ 312,022	$ 350,111
Total - Billing and Collecting		$ 7,325,900	$ 8,126,830	$ 10,799,691	$ 11,480,571	$ 11,688,482	$ 11,989,905

Account	Description	LRY Actual 2008	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Community Relations							
5405	Supervision	$ -	$ -	$ -	$ -	$ -	$ -
5410	Community Relations - Sundry	$ -	$ -	$ -	$ -	$ -	$ -
5415	Energy Conservation	$ -	$ -	$ -	$ -	$ -	$ -
5420	Community Safety Program	$ -	$ -	$ -	$ -	$ -	$ -
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5505	Supervision	$ -	$ -	$ -	$ -	$ -	$ -
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -	$ -
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -
Total - Community Relations		$ -			$ -	$ -	$ -
Account	**Description**	**LRY Actual 2008**	**2009 Actuals**	**2010 Actuals**	**2011 Actuals**	**2012 Bridge Year**	**2013 Test Year**
Administrative and General Expenses							
5605	Executive Salaries and Expenses	$ 713,422	$ 1,076,955	$ 941,501	$ 957,447	$ 498,010	$ 514,155
5610	Management Salaries and Expenses	$ 3,788,922	$ 3,395,178	$ 3,355,020	$ 3,718,522	$ 4,778,416	$ 5,530,836
5615	General Administrative Salaries and Expenses	$ 8,374,638	$ 8,835,139	$ 10,028,063	$ 9,933,167	$ 10,611,125	$ 11,365,039
5620	Office Supplies and Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5625	Administrative Expense Transferred - Credit	-$ 6,721,484	-$ 6,563,730	-$ 6,652,898	-$ 5,243,197	-$ 3,886,651	-$ 4,337,299
5630	Outside Services Employed	$ -	$ -	$ -	$ -	$ -	$ -
5635	Property Insurance	$ -	$ -	$ -	$ -	$ -	$ -
5640	Injuries and Damages	$ -	$ -	$ 5	$ 830,757	$ 1,007,600	$ 1,086,443
5645	Employee Pensions and Benefits	-$ 198,057	-$ 141,326	$ 92,926	$ 507,260	$ -	$ -
5650	Franchise Requirements	$ -	$ -	$ -	$ -	$ -	$ -
5655	Regulatory Expenses	$ 805,526	$ 958,872	$ 818,465	$ 846,426	$ 895,000	$ 1,091,500
5660	General Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -
5665	Miscellaneous General Expenses	$ 171,176	$ 1,130,202	$ 194,886	$ 110,345	$ 344,651	$ 313,020
5670	Rent	$ -	$ -	$ -	$ -	$ -	$ -
5675	Maintenance of General Plant	$ 5,986,118	$ 6,774,501	$ 6,975,162	$ 6,703,153	$ 8,202,564	$ 9,219,951
5680	Electrical Safety Authority Fees	$ 92,689	$ 94,156	$ 92,868	$ 95,899	$ 97,850	$ 97,850
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -	$ -
5695	OM&A Contra Account	$ -	$ -	$ -	$ -	$ -	$ -
6205	Donations (Charitable Contributions)	$ 31,228	$ 40,091	$ 50,445	$ 140,000	$ 145,000	$ 150,000
Total - Administrative and General Expenses		$ 13,044,178	$ 15,600,037	$ 15,896,443	$ 18,599,779	$ 22,693,565	$ 25,031,495
6105	Taxes Other Than Income Taxes	$ 866,050	$ 863,606	$ 867,586	$ 864,465	$ 1,075,000	$ 1,200,000
Total OM&A		$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,099,236

Note: If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

Appendix 2-G
OM&A Cost Driver Table ($ Millions)

OM&A	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Opening Balance (Millions)	$ 41.7	$ 36.2	$ 41.5	$ 45.6	$ 50.8	$ 57.0
Collective agreement/annual progressions	- 1.4	2.6	- 0.2	0.2	1.3	1.5
Benefit and pension costs	- 0.3	0.5	0.8	1.8	0.5	0.8
Bad debt	- 0.3	- 0.0	1.5	0.9	- 0.1	- 0.1
Distribution system maintenance & repair costs	0.2	0.7	- 0.0	0.2	- 0.1	0.3
Information solutions and technology services costs	- 0.3	0.2	0.5	- 0.2	0.5	0.1
Customer care costs	- 0.4	0.2	0.8	- 0.5	0.4	0.1
Asset management plan operating costs	-	-	-	0.1	0.2	0.9
New administrative office operating costs	-	-	-	-	0.8	0.8
Capitalization policy change	-	-	-	2.5	0.5	- 0.2
Other costs	- 2.9	1.2	0.7	0.1	2.2	- 0.1
Closing Balance	$ 36.2	$ 41.5	$ 45.6	$ 50.8	$ 57.0	$ 61.1

Notes:

(1) For each year, a detailed explanation for each cost driver and associated amount is required.

Collective agreement/annual progressions/new positions:
Annual compensation increases and progressions are governed by Enersource Hydro's Collective Agreement with the International Brotherhood of Electrical Workers for unionized staff. Enersource currently has a four year agreement that expires March 31, 2014. It provided for increases of 3.00% in the first and second years and provides for an increase of 3.25% in the third and fourth years of the Agreement.
Additional headcount requests were supported by position requisitions which identified job requirements. All new positions are approved by management.

Benefit and pension costs:
Increases in benefit and pension costs are primarily due to increases in OMERS pension expenses. Pension contributions have increased due to additional staff and the 2008 economic downturn which resulted in a funding deficit in the OMERS pension plan. To eliminate the funding deficit, OMERS introduced contribution increases for both the employee and employer portion. Refer to Exhibit 4, Tab 3, Schedule 1 for details on Enersource's pension costs.

Bad debt:
Since 2008, Enersource has experienced a significant increase in the amount and number of accounts deemed to be uncollectable. Enersource has attempted to mitigate this trend by hiring and Accounts Receivable Manager and selecting two new third party collection agencies. Refer to Exhibit 4 Tab 1 Schedule 2 for futher details.

Distribution system maintenance and repair costs:
Distribution system maintenance and repair include material and transportation costs as well as substation maintenance costs, underground maintenance and burn off repairs, overhead maintenance and repair costs and insulator washing. These costs are discussed in detail in Exhibit 4 Tab 1 Schedule 3.

Information system costs:

This costs driver represents increases in hardware/software maintenance, mainframe support costs and software licence renewal fees. Refer to Exhibit 4 Tab 1 Schedule 8 for further details.

Customer Care costs:
This cost driver represents increases in call centre and collections costs. These costs have increased due to the overall increase in the cost of power and Enersource's increased focus on customer accounts that are overdue. Refer to Exhibit 4 Tab 1 Schedule 2 ofr further details.

New administrative office:
Enersource has developed a flexible and executable strategic facilities plan that addresses the specific needs of the organization. The plan culminated with the acquisiton of a new administrative office. The incremental operating expenses for the new administrative office include salary costs, facility maintenance and repair costs, property taxes and utility costs. Further detail on the new administrative office is provided at Exhibit 2 Tab 2 Schedule 5 and Exhibit 4 Tab 1 Schedule 11.

Asset management:
Enersource has developed a detailed and integrated Asset Management Plan that identifies key distribution system maintenance and replacement programs over a five-year planning horizon. The AMP can be found in Exhibit 2 Tab 2 Schedule 2. The implementation of the AMP neccessitates additional staff and related costs to collect and analyze operational and asset information that had not been collected previously. For further details on AMP operating costs, refer to Exhibit 4 Tab 1 Schedule 4.

Capitalization policy change:
IFRS prescribes that only costs directly attributable to a specific asset can be capitalized. Under IFRS, indirect overhead costs can no longer be capitalized. These costs, referred to as overhead burdens, have resulted in an increase in Enersource's operating costs. Please refer to Exhibit 2 Tab 1 for further details on the change in capitalization policy.

(2) The closing balance for each year becomes the opening balance for the next year.
The 2008 Actual opening balance is Enersource's 2008 COS OM&A adjusted for smart meter costs.

(3)

If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

Appendix 2-H
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	2008 Rates	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
	(A)								
1	OEB Annual Assessment	5655	$ 840,000	$ 788,332	$ 804,172	$ 760,066	$ 768,055	$ 820,000	$ 854,000
2	OEB Hearing Assessments (applicant-originated)								
3	OEB Section 30 Costs (OEB-initiated)								
4	Expert Witness costs for regulatory matters								
5	Legal costs for regulatory matters								
6	Consultants' costs for regulatory matters								
7	Operating expenses associated with staff resources allocated to regulatory matters	5615	$ -	$ -	$ -	$ 293,226	$ 376,479	$ 426,072	$ 445,642
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5615	$ -	$ -	$ -	$ 10,866	$ 21,374	$ 54,030	$ 45,531
9	Other regulatory agency fees or assessments	5680	$ 88,000	$ 92,689	$ 94,156	$ 92,868	$ 95,899	$ 97,850	$ 97,850
10	Any other costs for regulatory matters (please define)								
11	Intervenor and legal costs	5655	$ 146,000	$ 17,194	$ 154,700	$ 58,399	$ 78,371	$ 75,000	$ 75,000
11	**Intervenor and legal costs (One time costs)**	5655	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,500
12	Sub-total - Ongoing Costs [3]		$ 1,074,000	$ 898,215	$ 1,053,028	$ 1,215,424	$ 1,340,179	$ 1,472,952	$ 1,518,023
13	Sub-total - One-time Costs [4]		$ -	$ -	$ -	$ -	$ -	$ -	$ 162,500
14	Total		$ 1,074,000	$ 898,215	$ 1,053,028	$ 1,215,424	$ 1,340,179	$ 1,472,952	$ 1,680,523

Notes:

1 Please identify the resources involved (conferences and publication of notices)

2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.

3 Sum of all ongoing costs identified in rows 1 to 11 inclusive.

4 Sum of all one-time costs identified in rows 1 to 11 inclusive.

Appendix 2-I
OM&A Cost per Customer and per FTEE

	LRY - 2008 Board Approved	LRY - 2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Customers	187,763	185,314	188,335	191,350	194,172	196,727	199,187
Total OM&A from Appendix 2-G	$ 41,653,058	$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,099,236
OM&A cost per customer	$ 221.84	$ 195.53	$ 220.48	$ 238.30	$ 261.54	$ 289.79	$ 306.74
Number of FTEEs (EHM & Corp)	368	360	378	383	377	383	391
Customers/FTEEs	510	515	498	500	515	514	509
OM&A Cost per FTEE	$ 113,188	$ 100,650	$ 109,851	$ 119,056	$ 134,703	$ 148,848	$ 156,264

Notes:

(1)
If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

(2) The method of calculating the number of customers must be identified.
The average number of customers is derived by taking the opening and closing customer figures each year, divded by 2.

(3) The method of calculating the number of FTEEs must be identified. See also Appendix 2-K.
The FTEE for each headcount is derived by taking the number of months in a year the headcount is employed divided by 12 months.

Variance Analysis Overview

The operating costs of Enersource are detailed at Exhibit 4 Tab 2 Schedule 1 Appendix 2-J. The operating costs will rise from the OEB-approved level for 2008 of $41,653 to $61,099 in the 2013 Test Year. Excluding the operating expenses due to certain key drivers that do not reflect the "business as usual" strategy of Enersource (IFRS overhead burdens, bad debts, asset management, one-time costs and the new administration office), total operating expenses in 2013 will be $51,703, representing a 4.4% average annual compound growth rate.

Further details are found in the Operating Costs Manager's Summary at Exhibit 4 Tab 1 Schedule 1, and the associate schedules and appendices, all at Exhibit 4 Tab 1.

Appendix 2-J
OM&A Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	2008 Board Approved	Last Board-approved Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	Most Current Actual Year (2011)	Bridge Year (2012)	Test Year (2013)	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
									Variance ($)	Percentage	Variance ($)	Percentage
Operations												
5005	Operation Supervision and Engineering	$ 2,206,533	$ 2,069,858	$ 2,238,397	$ 2,022,276	$ 2,047,475	$ 2,276,153	$ 2,528,872	$ 459,014	22.18%	$ 481,397	23.51%
5010	Load Dispatching	$ 1,837,223	$ 1,609,725	$ 2,087,224	$ 2,205,345	$ 2,394,218	$ 2,347,417	$ 2,489,936	$ 880,211	54.68%	$ 95,718	4.00%
5012	Station Buildings and Fixtures Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5016	Distribution Station Equipment - Operation Labour	$ 1,229,607	$ 1,037,193	$ 1,118,027	$ 1,267,573	$ 1,345,721	$ 1,454,928	$ 1,544,169	$ 506,976	48.88%	$ 198,448	14.75%
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 191,775	$ 140,982	$ 193,830	$ 139,348	$ 130,012	$ 150,500	$ 166,820	$ 25,838	18.33%	$ 36,808	28.31%
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 664,050	$ 643,391	$ 962,371	$ 937,618	$ 1,190,378	$ 1,310,887	$ 1,414,161	$ 770,770	119.80%	$ 223,783	18.80%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 151,653	$ 118,558	$ 259,376	$ 170,141	$ 221,926	$ 301,436	$ 309,967	$ 191,409	161.45%	$ 88,041	39.67%
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 2,065,916	$ 2,307,597	$ 2,906,901	$ 2,999,139	$ 3,330,111	$ 2,963,173	$ 3,211,590	$ 903,993	39.17%	-$ 118,521	-3.56%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 209,219	$ 225,829	$ 259,017	$ 276,648	$ 350,126	$ 286,880	$ 286,880	$ 61,051	27.03%	-$ 63,246	-18.06%
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5060	Street Lighting and Signal System Expense	$ -	$ 14	$ 9	$ -	$ -	$ -	$ -	-$ 14	-100.00%	$ -	
5065	Meter Expense	$ 1,928,711	$ 741,493	$ 383,175	$ 1,615,195	$ 1,370,747	$ 1,649,800	$ 1,030,569	$ 289,076	38.99%	-$ 340,178	-24.82%
5070	Customer Premises - Operation Labour	$ 1,371,607	$ 1,503,620	$ 1,586,206	$ 1,449,163	$ 1,605,236	$ 1,562,292	$ 1,629,935	$ 126,315	8.40%	$ 24,699	1.54%
5075	Customer Premises - Operation Materials and Expenses	$ 83,245	$ 85,767	$ 103,299	$ 74,083	$ 72,138	$ 87,540	$ 86,540	$ 773	0.90%	$ 14,402	19.97%
5085	Miscellaneous Distribution Expenses	$ 1,280,140	$ 1,099,800	$ 1,251,939	$ 1,519,957	$ 1,704,528	$ 2,196,496	$ 2,566,773	$ 1,466,973	133.39%	$ 862,245	50.59%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5096	Other Rent	$ 120,000	$ 118,912	$ 95,772	$ 93,868	$ 278,146	$ 265,000	$ 165,000	$ 46,088	38.76%	-$ 113,146	-40.68%
Total - Operations		$ 13,339,679	$ 11,702,739	$ 13,445,543	$ 14,770,356	$ 16,040,763	$ 16,852,502	$ 17,431,212	$ 5,728,473	48.95%	$ 1,390,449	8.67%

Account	Description											
Maintenance												
5105	Maintenance Supervision and Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5114	Maintenance of Distribution Station Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5120	Maintenance of Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5125	Maintenance of Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5130	Maintenance of Overhead Services	$ 1,996,771	$ 1,899,797	$ 2,285,880	$ 2,292,131	$ 2,407,930	$ 2,456,053	$ 2,679,514	$ 779,717	41.04%	$ 271,584	11.28%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 769,773	$ 815,164	$ 759,872	$ 779,104	$ 873,263	$ 879,101	$ 965,194	$ 150,030	18.40%	$ 91,931	10.53%
5145	Maintenance of Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5150	Maintenance of Underground Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5155	Maintenance of Underground Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5160	Maintenance of Line Transformers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ 980,100	$ 580,292	$ 441,795	$ 193,247	$ 516,449	$ 1,363,982	$ 1,801,916	$ 1,221,624	210.52%	$ 1,285,467	248.90%
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		$ 3,746,644	$ 3,295,253	$ 3,487,547	$ 3,264,481	$ 3,797,642	$ 4,699,136	$ 5,446,624	$ 2,151,371	65.29%	$ 1,648,982	43.42%
Account	**Description**											
Billing and Collecting												
5305	Supervision	$ 1,560,783	$ 1,000,824	$ 1,188,424	$ 2,171,582	$ 1,595,209	$ 3,669,783	$ 3,842,550	$ 2,841,726	283.94%	$ 2,247,341	140.88%
5310	Meter Reading Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5315	Customer Billing	$ 5,286,402	$ 4,973,379	$ 5,421,030	$ 5,398,083	$ 5,658,911	$ 4,106,677	$ 4,247,244	-$ 726,135	-14.60%	-$ 1,411,667	-24.95%
5320	Collecting	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5330	Collection Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5335	Bad Debt Expense	$ 1,575,000	$ 1,270,475	$ 1,252,636	$ 2,801,922	$ 3,706,065	$ 3,600,000	$ 3,550,000	$ 2,279,525	179.42%	-$ 156,065	-4.21%
5340	Miscellaneous Customer Accounts Expenses	$ -	$ 81,223	$ 264,741	$ 428,103	$ 520,385	$ 312,022	$ 350,111	$ 268,888	331.05%	-$ 170,274	-32.72%
Total - Billing and Collecting		$ 8,422,185	$ 7,325,900	$ 8,126,830	$ 10,799,691	$ 11,480,571	$ 11,688,482	$ 11,989,905	$ 4,664,005	63.66%	$ 509,334	4.44%

Account	Description											
Community Relations												
5405	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5415	Energy Conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5420	Community Safety Program	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5505	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
Account	**Description**											
Administrative and General Expenses												
5605	Executive Salaries and Expenses	$ 773,687	$ 713,422	$ 1,076,955	$ 941,501	$ 957,447	$ 498,010	$ 514,155	-$ 199,267	-27.93%	-$ 443,292	-46.30%
5610	Management Salaries and Expenses	$ 3,629,161	$ 3,788,922	$ 3,395,178	$ 3,355,020	$ 3,718,522	$ 4,778,416	$ 5,530,836	$ 1,741,914	45.97%	$ 1,812,314	48.74%
5615	General Administrative Salaries and Expenses	$ 8,546,004	$ 8,374,638	$ 8,835,139	$ 10,028,063	$ 9,933,167	$ 10,611,125	$ 11,365,039	$ 2,990,401	35.71%	$ 1,431,872	14.42%
5620	Office Supplies and Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5625	Administrative Expense Transferred - Credit	-$ 6,712,000	-$ 6,721,484	-$ 6,563,730	-$ 6,652,898	-$ 5,243,197	-$ 3,886,651	-$ 4,337,299	$ 2,384,185	-35.47%	$ 905,898	-17.28%
5630	Outside Services Employed	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5635	Property Insurance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5640	Injuries and Damages	$ -	$ -	$ -	$ 5	$ 830,757	$ 1,007,600	$ 1,086,443	$ 1,086,443		$ 255,686	30.78%
5645	Employee Pensions and Benefits	$ -	-$ 198,057	-$ 141,326	$ 92,926	$ 507,260	$ -	$ -	$ 198,057	-100.00%	-$ 507,260	-100.00%
5650	Franchise Requirements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5655	Regulatory Expenses	$ 986,000	$ 805,526	$ 958,872	$ 818,465	$ 846,426	$ 895,000	$ 1,091,500	$ 285,974	35.50%	$ 245,074	28.95%
5660	General Advertising Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5665	Miscellaneous General Expenses	$ 913,000	$ 171,176	$ 1,130,202	$ 194,886	$ 110,345	$ 344,651	$ 313,020	$ 141,844	82.86%	$ 202,675	183.67%
5670	Rent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5675	Maintenance of General Plant	$ 6,983,298	$ 5,986,118	$ 6,774,501	$ 6,975,162	$ 6,703,153	$ 8,202,564	$ 9,219,951	$ 3,233,833	54.02%	$ 2,516,798	37.55%
5680	Electrical Safety Authority Fees	$ 88,000	$ 92,689	$ 94,156	$ 92,868	$ 95,899	$ 97,850	$ 97,850	$ 5,161	5.57%	$ 1,951	2.03%
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
5695	OM&A Contra Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	
6205	Donations (Charitable Contributions)	$ 40,000	$ 31,228	$ 40,091	$ 50,445	$ 140,000	$ 145,000	$ 150,000	$ 118,772	380.33%	$ 10,000	7.14%
Total - Administrative and General Expenses		$ 15,247,150	$ 13,044,178	$ 15,600,037	$ 15,896,443	$ 18,599,779	$ 22,693,565	$ 25,031,495	$ 11,987,317	91.90%	$ 6,431,716	34.58%
6105	Taxes Other Than Income Taxes	$ 897,400	$ 866,050	$ 863,606	$ 867,586	$ 864,465	$ 1,075,000	$ 1,200,000	$ 333,950	38.56%	$ 335,535	38.81%
Total OM&A		$ 41,653,058	$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,099,236	$ 24,865,116	68.62%	$ 10,316,018	20.31%

Employee Compensation Breakdown

Enersource's Human Resources Strategy

Enersource relies heavily on having a highly skilled, properly trained and knowledgeable workforce to best serve its customers, execute its asset management plan ("AMP"), which includes maintaining and renewing aging infrastructure, respond to large municipal infrastructure projects, and attend to ongoing critical technological advances, and increasing legislative and regulatory requirements. The nature of this constantly-changing environment is not unique to Enersource and is faced by most other organizations in the electricity sector.

Enersource has been diligent in establishing strategic and integrated workforce planning as part of its annual corporate planning and budgeting processes, and as an ongoing business consideration to ensure it has a sustainable and prepared workforce in light of a rapidly transforming environment.

In order to continue to deliver on the core business, Enersource must continue to recruit and retain human resources to meet the ongoing business challenges.

Aging Workforce

Enersource continues to experience an increase in the number of employees electing to retire from the organization at their earliest unreduced eligibility date. The average age of retirement has declined to 59 from 60 years of age. This means that employees are electing to leave the organization at an earlier age, which in turn accelerates attrition rates due to retirement. The average age of Enersource's current workforce is 44 years.

Figure 1 below illustrates that 66 percent of Enersource staff is 40 years and older, and in the trades and technical group in particular, 62 percent of that staff is 40 years and older, as illustrated in Figure 2.

Figure 1: All Employees by Age Group

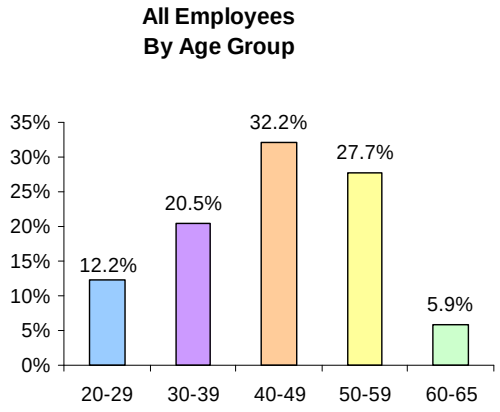
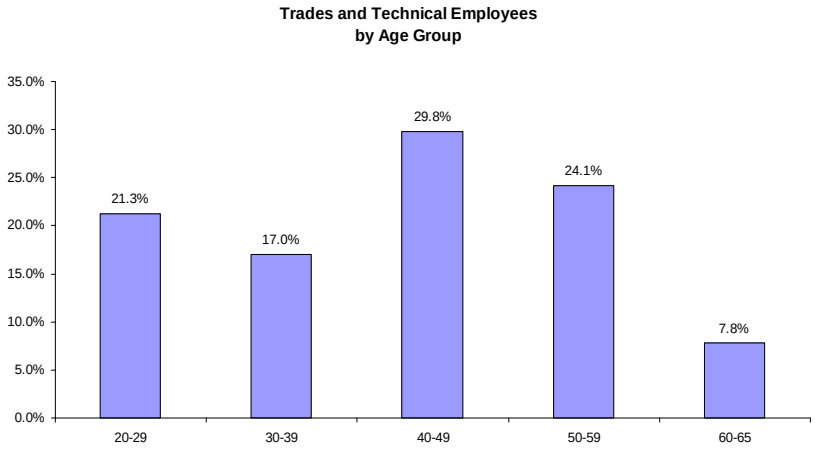


Figure 2: Trades and Technical Employees by Age Group



Enersource's need to continue to recruit and retain a skilled, prepared, and knowledgeable workforce remains a critical aspect of its human resource

strategy. As the number of retirements continues to grow over the next decade, Enersource's ability to deliver on its core business must be addressed through workforce planning to ensure sufficient skilled and trained resources are in place to meet demands.

Given the time required to ensure that staff is competent and capable of working in a highly-skilled and technical environment, Enersource's human resource strategy addresses apprenticeship requirements and staffing for other key areas of the business.

Table 1 below illustrates the number of eligible retirements for all employees for the next ten years.

Table 1: Eligible Retirements[1] for All Employees

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
18	8	7	10	6	17	19	9	9	4	107

Table 2 below illustrates the number of eligible retirements for the trades and technical group of employees for the next ten years.

Table 2: Eligible Retirements for Trades and Technical Employees

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
9	4	5	3	3	7	5	5	2	3	46

Of the 107 employees eligible to retire over the next ten year period, 46 of these are trades and technical employees. This represents 43 percent of the staff

[1] "Eligible Retirements" means able to retire with an unreduced pension.

eligible to retire. Over 25 percent of all employees are eligible to retire in the next ten years.

Demands of Aging Infrastructure

With two-thirds of its assets older than 25 years, Enersource has in place a comprehensive AMP (see Exhibit 2 Tab 2 Schedule 2 Appendix 1), which focuses on the maintenance and enhancement of its distribution system assets. With aging infrastructure, a fundamental requirement for the successful deployment of the AMP is the availability of a skilled and capable workforce. Continued efforts are required to manage the aging distribution system with key areas of focus on substations, distribution and substation transformers and switchgear, underground cable, and poles.

Demands of Customer Communication Changes

The nature of Enersource's relationships with customers is evolving. Customers demand and deserve timely and accurate responses to their inquiries, despite the increasing complexity of the sector, to which staff must be able to adapt. Electronic communications and payments are expected to become the norm for most customers, which require systems and trained staff to manage. Customer expectations are also increasing with respect to more expeditious response times, more dynamic websites, and increased ways to contact Enersource personnel. In addition, social media changes, which constitute a new element to utility communications, are increasingly being embraced by customers. This also requires Enersource to maintain its currency in these advancements, which are reflected in the skill sets of its communications staff.

Demands of Technological Advancements

The continued fast pace of technological developments and advancements is inevitably impacting the way Enersource conducts its business. Information technology connects and enables Enersource's ongoing business operations. Within the Ontario distribution sector, the convergence of operating technologies with information technology solutions is essential, particularly in the context of the development of a smarter grid. In the context of customer care, information technology is changing the way distributors communicate with customers, enabling customers to interact with their distributors as never before. These technological developments and advances require a workforce that is knowledgeable and skilled with the evolving technological landscape. Enersource must ensure that it has in place the specialized workforce to support and drive these technological advancements.

Demands of Policy and Regulatory Changes

As the electricity sector in Ontario is facing many new challenges, the government policy and regulatory frameworks are also adapting and changing in response to these challenges. As part of these changes, distributors are required to do more in the areas of, for example, low-income customers, smart meters and time-of-use pricing, conservation and demand management, and connections for renewable energy to meet the requirements of the Green Energy and Green Economy Act. This transforming government policy and regulatory landscape is placing additional demands on distributors and having a significant impact on human resourcing needs.

Human Resource Strategy

Under current trends, Enersource is facing an insufficient supply of skilled, prepared, and knowledgeable workers. This gap will occur at all levels of the company: engineers, technicians, technologists and specialists, trades people and management staff. Enersource has taken a proactive approach to succession planning and management over the last four years, which has resulted in the identification of employees who have potential to replace supervisory, managerial, or director-level employees who will be retiring. Any promotion of these employees will create additional staff movement and a domino effect throughout the organization.

In response to the changing environment and to ensure that Enersource has a sustainable, skilled-prepared, and knowledgeable workforce, Enersource has developed a human resource strategy to sustain current organizational effectiveness and address emerging requirements.

Preserving and Sustaining the Trades

In 2004, a study conducted by the Canadian Electricity Human Resource Sector[2] concluded that by 2015, 17,000 technicians would be required in order to sustain the trades unique to the industry.

As explained above, Enersource will experience a significant increase in the number of employees eligible to retire in the next decade. Additional attrition factors including resignations and internal promotions of existing employees to supervisory and management levels to backfill retirements, will also contribute to labour and knowledge shortage.

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[2] *Keeping the Future Bright,* 2004 Canadian Electricity Human Resource Sector Study, p. 5.

The increased actual and impending retirements at Enersource in the trades and technical group, the work requirements associated with the AMP and municipal infrastructure projects which are substantially executed by the trades and technical workforce, and the four-year time period required to become proficient and certified journeymen[3], has resulted in Enersource having invested and continuing to invest in apprenticeship programs.

As depicted in Table 3 below, since the implementation of the recent apprenticeship programs, Enersource has hired 65 apprentices in the trades group consisting of linemen and cablemen, system control operators, substation technicians/technologists and meter technicians. Fifty-three, or 81 percent, of the apprentices have been retained throughout this period. Attrition has been due to a number of factors including apprentices pursuing other opportunities within Enersource, failing to be successful in the apprenticeship program, or obtaining employment outside of the company. Of the 40 linemen and cablemen apprentices hired to date, seven of these employees attained their journeymen certification by 2010, three in 2011, three are projected to become journeymen in 2012, and another six are projected to become journeymen in 2013.

[3] The masculine use of the names of these trades is born of convention. Enersource is proud to be an equal opportunity employer.

Table 3: Apprentices Hired and Retained, by Trade

	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Lineman/Cableman	5	3	4	6	6	5	4	3	4	40
System Control Operator	2			1	1	2				6
Substation Technician/Technologist		1	2	2	2	1				8
Meter Technician	2	2	2		2		2	1		11
Total Hired	9	6	8	9	11	8	6	4	4	65
Total Retained	9	6	6	6	8	8	5	1	4	53

Enersource's human resources strategy is multi-faceted and incorporates the following factors for each trades and technical group:

- Attrition through retirements, resignations, disability, death, etc.;
- Organic growth in customer base, particularly in the area of individual metered suites ("IMS");
- AMP work requirements and major projects; and
- Anticipated dates apprentices will obtain their journeyman status.

One projection from the human resource strategy is that in the next twelve years, 90 employees are, or will turn, 65 years of age and will be eligible to retire. Of these 90 employees, 25 or 28% are in trades positions.

Additional Requirements for Linemen/Cablemen

In the linemen/cablemen trade the anticipated retirements will reduce the number of qualified journeymen available to meet the additional work requirements associated with the AMP, other municipal infrastructure projects, and organic growth in the customer base, especially IMS.

Table 4 illustrates the number of linemen/cablemen eligible to retire between 2012 and 2021.

Table 4: Eligible Retirements of Linemen/Cablemen Maintainers

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
6	3	2	2	3	4	3	3	1	2	29

Enersource's partnership with Cambrian College has resulted in the provision of Enersource equipment to assist in the delivery of the college's two-year Powerline Technician program. Enersource works collaboratively with Cambrian College and Conestoga College to hire co-op students from their respective Powerline Technician programs. This provides hands-on experience in the utility environment and prepares the student for an apprentice position upon graduation. The graduates of these programs have learned solid skills and are better equipped to perform effectively in the in-house apprenticeship program leading to journeyman status within the four-year time period. Enersource's recruitment strategy is to continue to utilize co-op terms to assess students and, where appropriate, provide offers of employment to returning students, contingent upon completion of the college program. Enersource plans to continue recruiting and hiring four to six new apprentices each year consistent with vacancies created through attrition due to resignations and retirements.

Business Needs Driven by Strategic Priorities and the Regulated External Environment

The fast pace of the changing industry environment and its associated shifting business requirements has a major impact on Enersource's workforce, its complement, required abilities, skills and knowledge and has, in the following instances, created the need for additional dedicated resources.

Strategic Priorities - Strengthening Key Support Functions

In 2011, Enersource strengthened its capacity in key support areas to better meet its business objectives and priorities, to support the operations of the business, and ensure compliance with requirements and sustainability of the business. The Finance, Risk Management, Communications, and Health, Safety and Security functions were improved to ensure Enersource's ability to deliver on key strategies with respect to the sustainability of its workforce, emergency preparedness, business continuity, environment, financial, and internal and external communications. As well, increased legislative and program requirements in these areas including those related to the International Financial Reporting Standards ("IFRS"), changes to health and safety and environmental legislation, apprenticeship training, and customer relations necessitated that these functions be supplemented.

Additionally, Enersource's information and technology applications are being upgraded and integrated to ensure that it can respond to the required technological developments and advancements particularly related to the management of Enersource's aging infrastructure, smart grid and smart technologies, and support a more adept technical labour pool.

The increasingly complex regulatory environment and mandated deliverables, the requirement of the organization to deliver on the AMP, key municipal infrastructure projects such as the City of Mississauga's Metrolinx project, and time-of-use implementation have all created a need for additional staff resources to support the delivery of these concurrent multiple objectives. In addition, the acquisition of an Administration Office in 2012 will result in a need for additional support staff to service both buildings.

Enersource will continue to experience the effect of the changing landscape in which it operates, including experiencing the full impact of employee demographics and the associated loss of highly skilled, experienced, and knowledgeable employees due to retirements. The responses to this rapidly changing environment if not proactive and meaningful, will inevitably hamper the continued successes of the organization and challenge the organization's ability to fulfill its responsibilities to its customers. Enersource must maintain and ensure that the current level of its business is sustained throughout these changing times by ensuring that it has a sufficient, sustainable, and prepared workforce.

Enersource's multi-faceted Human Resource strategy manages the effect of these changes and ensures that the appropriate resources are in place to meet the long-term needs of the business and its customers.

Enersource's customers expect accuracy and efficiency from their service provider. Increasingly they are demanding a greater degree of sophistication in the communication of their billing and consumption information and ways to manage better their electricity usage. Regulatory requirements are increasing and there are often changes that must be implemented quickly and efficiently. Enersource needs the technology and business infrastructure to meet these demands and the experts to manage the resulting systems and technology.

Table 5 lists the resulting new positions in 2011 and 2012, and those proposed for 2013.

Table 5: Strengthening Key Support Functions

2011 Positions	2012 Positions	2013 Positions
Cashier (temporary)	Cashier	JDE Business Analyst
Manager, Collections	Manager, Collections	Internet Developer
Client Services Technician	Application Manager	Oracle BI Developer
Supervisor, System Control		Network Technician
Supervisor, Metering		Business Analyst (2)
Meter Data Coordinator		Mapping Analyst
		Application Manager
		Substation Technician
		Facilities Caretaker
		Facilities Analyst

Employee Complement

Temporary employees are used to staff projects, back-fill for staff seconded to projects, or replace employees on leave. Including temporary employees in the count provides a better indication of resource requirements each year and therefore the staffing numbers in Exhibit 4 Tab 3 Schedule 1 Appendix 2K include temporary employees.

Executive

Executive staff in 2012, with no changes proposed for 2013, includes the President & Chief Executive Officer ("CEO"), the Chief Operating Officer ("COO"), the Chief Financial Officer ("CFO") and the following Vice Presidents:

- Vice President, Engineering and Operations;
- Vice President, Finance; and
- Vice President, Human Resources.

In 2011, the Executive group also included the Vice President, Customer Care and Billing Operations. Upon retirement of the incumbent, executive leadership for these duties were assigned to the COO and the VP, Finance. Prior to 2009, the Executive also included a Vice President, Health and Safety.

Through reorganization, executive leadership for these responsibilities is now provided through the COO.

Management

The Management group includes directors, managers, and supervisors. As discussed earlier, additional staff is needed to strengthen the capacity in key support areas in order to meet Enersource's business objectives and priorities, support the operations of the business and customer service, and ensure compliance and sustainability as it relates to the requirements of the business.

Non-Union Positions

Included in the non-union group are the professional staff at Enersource, including, but not limited to, engineers and engineers-in-training, analysts, auditors, programmers, and executive assistants.

Union Positions

The unionized workforce is represented by the International Brotherhood of Electrical Workers (“IBEW”). The represented employees include both tradespersons and administrative/clerical staff, sometimes referred to as “outside” and “inside” staff, respectively.

Total Compensation

Compensation increases arise from annual increases in base pay for existing staff, increasing costs for benefits programs, additional positions identified through workforce planning, and the transfer of positions between the parent company, Enersource Corporation and Enersource. Union overtime is primarily affected by the number and type of power outages in the year, which in turn are typically affected by weather.

Annual Increases to Base Pay

As of April 1, 2010, a new four-year collective agreement ("Collective Agreement") was reached with the IBEW. In preparation for bargaining, Enersource reviewed other Collective Agreement settlements within the sector. Informed by these precedents, Enersource negotiated an agreement that balanced fiscal requirements with operational stability. The Collective Agreement includes a 3% annual increase in unionized wages for 2010 and 2011, and a 3.25% increase in each of 2012 and 2013. These percentages are consistent with increases negotiated within the industry and, in conjunction with only minor enhancements to the benefits plan, allowed Enersource to ensure workforce stability, and established costs for a four-year period.

Increases for non-union employees from 2009 to 2011 were comparable to increases for unionized employees. In 2012, recognizing the projected increases in the general employment market, the base salary increase for non-union employees averaged 2.5%, lower than the salary increase negotiated in the Collective Agreement for unionized workers.

Other Factors Affecting Compensation

Other factors included in total compensation are overtime for unionized staff, benefits, and the incentive plan for all employees.

Incentive Pay

The incentive plan will continue in the 2013 Test Year. The incentive plan is based on the following performance measures:

- Reliability;
- Safety;
- Electricity Service Quality Requirements ("ESQR"); and
- Enersource Net Income.

Enersource's incentive plan components for reliability, safety, and ESQR measures are included in the Application budget. The net income component is not part of the Application and is paid by the shareholders.

Benefits Costs

Benefit coverage for all employees includes coverage for prescription drugs, vision, dental care, paramedical services, hearing aids, employee assistance counselling and services, long term disability insurance, life insurance, and accidental death and dismemberment insurance. In addition to these benefits, non-union employees also have out-of-country health care coverage and access to a health care spending account for health and dental expenses not covered under the basic plan.

Enersource has successfully managed benefits costs with its carriers, and increases have been lower than the trends in health care increases. Historical

increases[4] from 2008 to 2011 have been 15% for healthcare and 8% for dental, while Enersource's increases in premium costs have average 4.6% and 3.4%, respectively, from 2008 to 2011.

However, despite Enersource's past success in managing its benefits costs with carriers to below the average trends in healthcare costs, it is expected that these costs will rise in the future. Based on information from the Morneau Shepell Report[5], at Exhibit 1 Tab 3 Schedule 1 Appendix 4, forecasted increases to dental rates are 4% per year in 2012 and 2013, and for health care, 8.5% in 2012, and 9% in 2013.

Pension Costs

Enersource's participation in OMERS is mandatory based on provincial legislation. Pension contributions have increased because of additional staff. As well, due to the 2008 global economic downturn, OMERS has experienced a funding deficit which is growing. As a result, OMERS introduced contribution increases, equal to 1% in 2011, and 1% in 2012. OMERS has stated that it will require an overall increase in contributions in 2013 of 0.9%, but it is unknown what the individual rate increases will be for the different types of members within OMERS. Enersource is one of several different member types.

Increases to the employer portion have increased the cost of providing the pension benefits. Pursuant to OMERS' funding strategy, the projected increase has been incorporated into the 2013 budget.

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[4] Enersource's benefits consulting partners, The Williamson Group, in its report entitled *"Enersource Corporation, August 1, 2011 Renewal Report"*, p. 7 and p. 16. The relevant excerpts are found at Exhibit 4 Tab 3 Schedule 1 Appendix 1.

[5] *Post-Employment Benefits for Employees of Enersource Corporation, Accounting Report as at December 31, 2011*. Prepared January, 2012, by Morneau Shepell. Actuarial assumptions are found at page 4.

Table 6 provides the pension contribution rates that Enersource has been required to make from 2008 to 2012.

Table 6: Enersource Pension Contribution Rates for Members with a Normal Retirement age of 65

	2008	2009	2010	2011	2012
Up to CPP earnings limit	6.5%	6.3%	6.4%	7.4%	8.3%
Above CPP earnings limit	9.7%	9.5%	9.7%	10.7%	12.8%

Enersource also provides post-employment life, health, and dental benefits to its employees. Enersource uses an actuary to determine the cost of these benefits as well as measure the plan obligation. The accrued post-employment life, health, and dental liability at the date of Enersource's transition from CGAAP to IFRS is in excess of $4,000.

Enersource will continue to receive a full report every three years and material updates from the actuary in the intervening years under IFRS.

The ultimate cost of a defined-benefit plan may be influenced by many variables, such as final salaries, employee turnover and mortality, employee contributions, and medical cost trends.

Impact to Enersource at the Date of Transition

Enersource recognized the entire one-time transition obligation as a vested past service cost and all re-measurements at the date of transition to IFRS as opening adjustments to retained earnings. The net impact to Enersource at the date of transition was a reduction of the post-employment accrued liability of $150.

Future Re-Measurements

Actuarial gains and losses result from increases or decreases in the present value of the defined-benefit obligation because of changes in actuarial assumptions and adjustments due to experience. Some examples of causes of actuarial gains and losses include:

- unexpectedly high or low actual rates of employee turnover, early retirement, or mortality, or increases in salaries, benefits (if the formal or constructive terms of the plan provide for inflationary benefit increases), or medical costs;
- the effect of changes to assumptions concerning benefit payment options;
- the effect of changes in estimates of future employee turnover, early retirement or mortality, or of increases in salaries, benefits (if the formal or constructive terms of a plan provide for inflationary benefit increases), or medical costs; and
- the effect of changes in the discount rate.

In transitioning to IFRS, the CGAAP amortization or “corridor approach” for actuarial gains and losses exceeding 10% was removed. As a result, Enersource will recognize actuarial gains and losses or re-measurements immediately in Other Comprehensive Income (“OCI”) rather than amortize them. The actuary loss for Enersource at the end of 2011 was $769.

Based on the above, Enersource is seeking to recover over one year the net change of $619 from the transition to IFRS and the 2011 actuary loss. Details are also found at Exhibit 9 Tab 1 Schedule 1. See Table 7 below.

Table 7: Post-Employment Benefit Accounting Impacts ($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**

THE WILLIAMSON GROUP

ENERSOURCE CORPORATION

August 1, 2011 Renewal Report

Manulife Financial Policy No. 38553

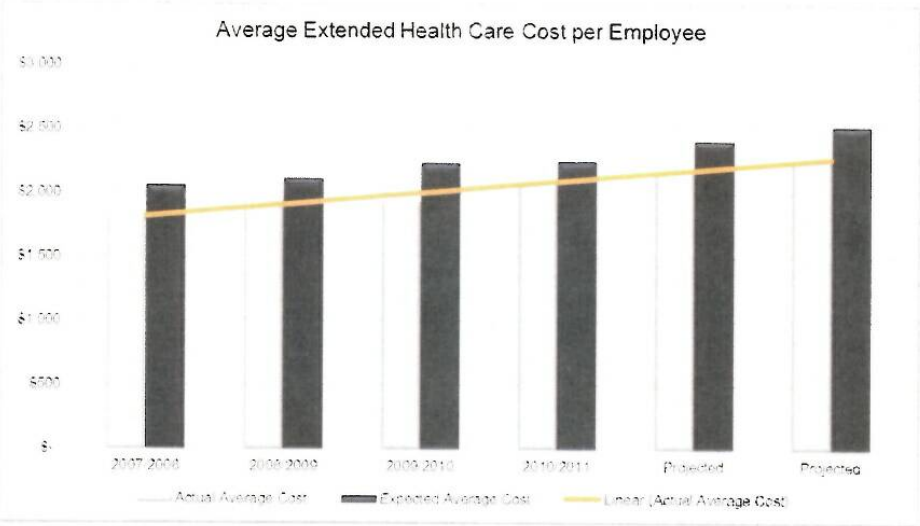
HEALTH AND WEALTH SOLUTIONS

THE WILLIAMSON GROUP

HEALTH AND
WEALTH SOLUTIONS

The chart below illustrates the average extended health care cost per employee (employee, spouse and dependents combined) for the past four years as well as projects the upcoming two years based on historical trend.

- The insurance industry expects that extended health care spending will increase by 15% year over year.
- Your employee cost has been much lower than industry expectations at an average of 4.6% over the four year period.



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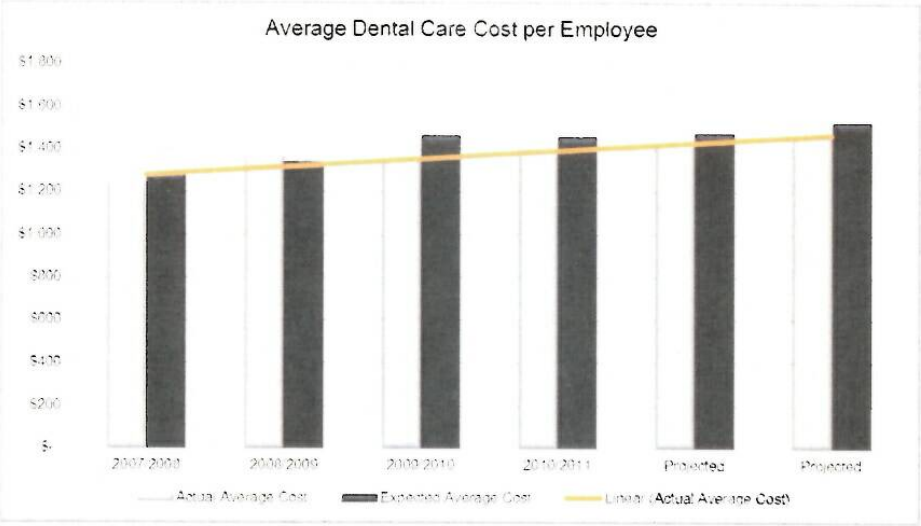
HEALTH AND WEALTH SOLUTIONS

The chart below illustrates the average dental care cost per employee (employee, spouse and dependents combined) for the past four years as well as projects the upcoming two years based on historical trend.

- The insurance industry expects that dental care spending will rise by approximately 8% per year.
- Your employee costs are averaging 3.4% over the four year period.



	ENERSOURCE HYDRO MISSISSAUGA							
		2008 COS	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Employees (FTE's including Part time								
Executive		4.00	4.00	3.00	3.00	3.00	2.00	2.00
Management		38.00	41.00	42.00	46.25	48.00	50.00	51.00
Non Union		49.00	44.83	52.92	52.00	54.67	54.00	59.00
Union		227.00	220.91	228.00	226.41	219.58	225.00	227.00
Total		318.00	310.74	325.92	327.66	325.25	331.00	339.00
Number of Part Time Employees								
Executive		-	-	-	-	-	-	-
Management		-	-	-	-	-	-	-
Non Union		-	0.50	1.00	2.00	2.00	2.00	2.00
Union								
Total		-	0.50	1.00	2.00	2.00	2.00	2.00
Total Salary and Wages								
Executive		531,374	537,196	476,209	496,724	516,024	376,074	389,610
Management		2,998,076	3,381,349	4,114,967	3,734,280	4,798,318	4,754,997	4,927,070
Non Union		2,999,570	3,047,023	3,634,927	4,444,288	4,375,879	4,501,656	4,651,064
Union		13,487,693	14,409,187	15,530,928	14,950,646	15,439,214	13,882,574	14,659,450
Total		20,016,713	21,374,755	23,757,031	23,625,937	25,129,434	23,515,302	24,627,194
Current Benefits								
Executive		234,347	241,570	199,204	221,024	212,383	151,715	224,482
Management		1,405,315	1,494,519	1,707,106	1,736,315	1,961,873	1,866,033	2,072,155
Non Union		1,296,928	1,340,177	1,502,347	1,869,918	1,784,416	1,736,841	1,903,318
Union		4,669,585	4,960,723	5,211,861	5,611,853	6,707,141	7,058,536	7,464,473
Total		7,606,175	8,036,989	8,620,519	9,439,111	10,665,814	10,813,125	11,664,428
Accrued Post-Retirement Benefits								
Executive		3,159	3,111	2,365	2,434	2,424	2,663	2,836
Management		46,327	45,611	34,672	35,696	35,539	39,050	41,592
Non Union		48,423	47,674	36,241	37,311	37,146	40,817	43,473
Union		222,204	218,768	166,301	171,211	170,458	187,300	199,491
Retirees		170,256	167,624	127,422	131,185	130,608	143,512	152,854
Total		490,369	482,788	367,000	377,837	376,174	413,342	440,246
Total Benefits (Current + Accrued)								
Executive		237,506	244,681	201,569	223,458	214,807	154,379	227,318
Management		1,451,642	1,540,130	1,741,778	1,772,011	1,997,412	1,905,083	2,113,747
Non Union		1,345,351	1,387,851	1,538,588	1,907,229	1,821,562	1,777,658	1,946,792
Union		4,891,788	5,179,492	5,378,162	5,783,064	6,877,599	7,245,836	7,663,964
Retirees		170,256	167,624	127,422	131,185	130,608	143,512	152,854
Total		8,096,544	8,519,778	8,987,519	9,816,947	11,041,988	11,226,468	12,104,674
Total Compensation (Salary, Wages & Benefits)								
Executive		768,880	781,877	677,778	720,182	730,831	530,452	616,928
Management		4,449,718	4,921,479	5,856,745	5,506,291	6,795,730	6,660,080	7,040,817
Non Union		4,344,921	4,434,874	5,173,515	6,351,517	6,197,441	6,279,314	6,597,855
Union		18,379,481	19,588,678	20,909,090	20,733,710	22,316,813	21,128,410	22,323,413
Total		27,943,001	29,726,909	32,617,127	33,311,700	36,040,814	34,598,257	36,579,014
Compensation - Average Yearly Base Wages								
Executive		132,844	134,299	158,736	165,575	172,008	188,037	194,805
Management		78,897	82,472	97,975	80,741	99,965	95,100	96,609
Non Union		61,216	67,968	68,687	85,467	80,042	83,364	78,832
Union		59,417	65,227	68,118	66,034	70,312	61,700	64,579
Total		332,373	349,966	393,517	397,817	422,327	428,201	434,825
Compensation - Average Yearly Overtime								
Executive		-	-	-	-	-	-	-
Management		1,814	3,509	6,434	4,489	5,766	4,508	4,761
Non Union		1,441	1,082	4,036	3,225	2,821	2,326	2,293
Union		3,401	10,013	11,354	9,710	11,682	4,823	5,378
Total		6,656	14,604	21,824	17,424	20,269	11,657	12,431
Compensation - Average Yearly Incentive Pay								
Executive		18,852	25,177	24,055	40,235	45,870	73,402	75,787
Management		6,931	8,579	8,563	6,120	7,633	7,529	7,681
Non Union		3,585	5,233	4,144	4,153	4,308	3,897	3,766
Union		3,372	4,628	4,165	3,063	3,687	3,236	3,417
Total		32,741	43,618	40,927	53,571	61,498	88,065	90,652
Compensation - Average Yearly Benefits								
Executive		59,377	61,170	67,190	74,486	71,602	77,189	113,659
Management		38,201	37,564	41,471	38,314	41,613	38,102	41,446
Non Union		27,456	30,958	29,074	36,677	33,319	32,920	32,996
Union		21,550	23,446	23,588	25,542	31,322	32,204	33,762
Total		146,584	153,139	161,323	175,020	177,856	180,414	221,864
Total Compensation		27,943,001	29,726,909	32,617,127	33,311,700	36,040,814	34,598,257	36,579,014
Total Compensation charged to OM & A		20,756,025	20,993,072	23,116,503	23,064,959	26,650,212	27,147,228	29,017,894
Total Compensation Capitalized		7,186,976	8,733,837	9,500,625	10,246,740	9,390,602	7,451,028	7,561,120
			-	-	-	-		
***AVERAGE YEARLY BENEFITS INCLUDES BOTH RETIREE AND CURRENT BENEFITS per JK								

	ENERSOURCE CORPORATION							
		2008 COS	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Employees (FTE's including Part time								
Executive		5.00	4.00	4.00	3.00	4.00	5.00	5.00
Management		12.00	13.00	13.00	14.00	12.00	12.00	12.00
Non Union		18.00	17.08	18.33	22.42	20.50	20.00	20.00
Union		15.00	15.50	16.41	15.83	15.33	15.00	15.00
Total		50.00	49.58	51.74	55.25	51.83	52.00	52.00
Number of Part Time Employees								
Executive		-	-	-	-	-	-	-
Management		-	-	-	-	-	-	-
Non Union								
Union			-	-	-	-	-	-
Total		-	-	-	-	-	-	-
Total Salary and Wages								
Executive		719,711	635,547	675,007	598,687	727,405	797,890	939,219
Management		1,107,160	1,065,583	1,304,406	1,411,106	1,245,496	975,942	1,199,765
Non Union		831,337	800,118	1,004,076	1,225,896	1,284,012	1,747,156	1,999,608
Union		759,166	715,434	704,864	786,406	790,026	840,856	838,517
Total		3,417,374	3,216,681	3,688,352	4,022,095	4,046,939	4,361,844	4,977,109
Current Benefits								
Executive		283,948	279,616	254,085	307,957	347,766	414,664	445,312
Management		473,457	464,381	449,475	721,869	589,870	522,495	550,783
Non Union		349,020	342,695	409,767	620,278	603,325	932,930	997,509
Union		306,296	286,477	259,014	392,265	366,444	443,033	500,498
Total		1,412,721	1,373,168	1,372,341	2,042,369	1,907,405	2,313,121	2,494,101
Accrued Post-Retirement Benefits								
Executive		2,369	2,190	1,675	2,972	2,813	2,894	3,082
Management		8,766	8,105	6,199	10,995	10,408	10,708	11,405
Non Union		13,069	12,082	9,241	16,391	15,516	15,963	17,002
Union		10,499	9,706	7,424	13,168	12,465	12,824	13,659
Retirees		18,457	17,064	13,052	23,150	21,914	22,546	24,013
Total		53,160	49,148	37,592	66,676	63,116	64,936	69,163
Total Benefits (Current + Accrued)								
Executive		286,317	281,806	255,760	310,929	350,579	417,558	448,394
Management		482,224	472,486	455,674	732,864	600,278	533,203	562,188
Non Union		362,088	354,777	419,008	636,669	618,841	948,893	1,014,511
Union		316,795	296,183	266,439	405,433	378,909	455,857	514,157
Total		1,447,424	1,405,252	1,396,881	2,085,895	1,948,607	2,355,511	2,539,250
Total Compensation (Salary, Wages & Benefits)								
Executive		1,006,028	917,353	930,767	909,616	1,077,984	1,215,448	1,387,613
Management		1,589,384	1,538,069	1,760,080	2,143,970	1,845,774	1,509,145	1,761,953
Non Union		1,193,425	1,154,895	1,423,084	1,862,565	1,902,853	2,696,049	3,014,119
Union		1,075,961	1,011,617	971,302	1,191,838	1,168,935	1,296,713	1,352,674
Total		4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Compensation - Average Yearly Base Wages								
Executive		143,942	158,887	168,752	199,562	181,851	159,578	187,844
Management		92,263	81,968	100,339	100,793	103,791	81,328	99,980
Non Union		46,185	46,845	54,778	54,679	62,635	87,358	99,980
Union		50,611	46,157	42,953	49,678	51,535	56,057	55,901
Total		333,002	333,857	366,822	404,712	399,812	384,321	443,706
Compensation - Average Yearly Overtime								
Executive			-	-	-	-	-	-
Management			-	-	59	-	-	-
Non Union			87	191	305	431	-	-
Union		333	-	8	57	276	854	854
Total		333	87	199	420	708	854	854
Compensation - Average Yearly Incentive Pay								
Executive		36,364	38,472	48,397	87,276	63,565	63,159	65,212
Management		11,693	9,136	9,214	9,595	10,162	11,297	11,664
Non Union		4,367	3,895	4,428	2,708	3,451	3,761	3,883
Union		4,817	3,945	3,161	2,143	3,153	3,230	3,335
Total		57,241	55,448	65,200	101,721	80,331	81,447	84,094
Compensation - Average Yearly Benefits								
Executive		57,263	70,452	63,940	103,643	87,645	83,512	89,679
Management		40,185	36,345	35,052	52,347	50,023	44,434	46,849
Non Union		20,116	20,771	22,859	28,397	30,187	47,445	50,726
Union		21,120	19,109	16,236	25,612	24,717	30,390	34,277
Total		138,684	146,677	138,087	209,999	192,572	205,780	221,531
Total Compensation		4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation charged to OM & A		4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation Capitalized								
***AVERAGE YEARLY BENEFITS INCLUDES BOTH RETIREE AND CURRENT BENEFITS per JK								

Shared Services/Corporate Cost Allocation

Overview

Enersource Corporation ("EC") is the holding company for the EC family of companies. EC provides corporate governance through the Board of Directors and strategic direction through the office of the President and CEO. EC provides administrative and operational services to Enersource Hydro Mississauga Inc. ("Enersource"), through the following departments: Finance, Human Resources, Corporate Relations, Internal Audit and Enterprise Risk, Purchasing, and Legal.

The Finance department supports Enersource with financial and accounting services, rate setting, and financial analysis. The Human Resources department supports Enersource with resource development and workforce sustainment. The strategic focus of Corporate Relations is to develop and enhance Enersource's brand and reputation, consistent with the strategic plan of the organization. Internal Audit and Enterprise Risk manages the ongoing assessment and reporting of all entity risks, including environmental and business continuity risks faced by the corporation, as well as overseeing the Internal Audit function. EC allocates costs to Enersource and other operating affiliates based on a cost recovery basis only. In 2008, EC renewed its focus on core competencies and revised its shared services model and agreements. The service agreements between EC and all affiliate companies have been provided at Exhibit 4 Tab 4 Appendices 1 to 6.

Beginning in 2009, EC's method of allocating costs was revised to better align with the amount of services being provided to each affiliate based on either budgeted headcount or as a percentage of revenue. The total cost of corporate services and the percentage allocated to Enersource from 2008 to 2013 are shown at Exhibit 4 Tab 4 Schedule 1 Appendix 2-L.

Enersource uses a fully allocated cost approach for its shared services which is in conformity with the *Affiliate Relationships Code* for Electricity Distributors and Transmitters *("Electricity ARC")*.

EC's Board of Directors

EC is governed by a Board of Directors ("BoD") that has ultimate accountability for the overall direction and results of the EC family of companies ("the Corporation"). The principal role of the BoD is the stewardship of the Corporation on behalf of the shareholders. The BoD oversees the conduct of the business and the performance of the Corporation's management ("Management") who are responsible for the day-to-day operation of the business.

The BoD currently has ten Directors. Eight Directors, including the Mayor of the City of Mississauga (the "City"), are appointed by the City, and two Directors are appointed by BPC Energy Corporation. The Chairman of the Board ("Chairman") is elected by the BoD from among the Directors appointed by the City, and is a separate role from the President and Chief Executive Officer. The principal role of the Chairman, as the presiding member of the BoD and accountable to the BoD, is to ensure that the relationships between the BoD and Management, the shareholders, other stakeholders and the individuals on the BoD are managed effectively and efficiently, and function in the best interest of Enersource.

Management strives to ensure that Directors are kept fully informed of all relevant information, such as orientation information explaining the history of the Corporation and the industry within which it operates, as well as financial and budget information, and the Corporation's overall strategic direction.

The Corporation promotes integrity as one of the foundations of its vision and values. In order to further encourage and promote a culture of ethical business

conduct, the BoD has adopted a written Code of Conduct for all Directors, officers, and employees. The Code of Conduct has been distributed to all directors, officers, and employees, all of whom are required to confirm in writing their adherence. Additional copies of the Code of Conduct are available on the Corporation's intranet and from the Human Resources department. The Code of Conduct is found at Exhibit 4 Tab 4 Schedule 1 Appendix 7.

Compliance by Directors is monitored by the Chairman through his observations of compliance and through annual interviews between himself and each Director. Compliance by officers and employees is assessed by the Ethics Committee, and violations are reported to the Human Resources & Corporate Governance Committee. The Corporation employees may report violations anonymously using a confidential telephone number or via electronic submission, monitored by an objective third party.

BoD remuneration is reviewed by the Human Resources & Corporate Governance Committee and, as appropriate, it makes recommendations to the BoD for amendments. All amendments to Director remuneration must be approved by the shareholders.

The BoD has established various committees to address specific areas and responsibilities. Any responsibility not delegated to a committee of the BoD or to Management remains with the BoD. There are four BoD Committees: the Audit Committee; the Human Resources & Corporate Governance Committee; the Development Committee; and the Health, Safety, Security & Environment Committee.

CEO Office

EC's executive team business unit is comprised of the Corporation's President and Chief Executive Officer, the Executive Vice President and Chief Financial Officer, the Vice President Human Resources, and the General Counsel. This business unit oversees the alignment of business practices and strategies with the goals of Enersource and other affiliates, and drives performance by managing risks and opportunities. This business unit is accountable to EC's BoD through the President and Chief Executive Officer.

Since 2008, this area has been focused on implementing the Corporation's strategic plan which is actionable on all fronts with the full translation of its corporate goals into each employee's personal performance, goals, and objectives. Many of the strategic initiatives within the plan have been assigned to cross-functional teams thereby ensuring a successful outcome for the Corporation. The focal points of the strategic plan are:

Business Engagement:

- Strategic Capital Flexibility;
- Strategic Investments; and,
- Revenue Stabilization.

External Engagement:

- Communications Enhancement; and,
- Enersource Brand Enhancement.

Organizational Engagement:

- Resource Development;

- Organizational Enhancement;
- Health and Safety; and
- Business Risk Mitigation.

Capital flexibility is a key driver for implementation of the strategic plan. Flexible debt and equity funding, where appropriate, will enable the Corporation to pursue strategic investment opportunities that meet the business and return criteria set by the BoD.

Asset investments must generate appropriate and timely returns. Asset investment opportunities would include utility acquisitions and distribution infrastructure development projects.

Enersource has developed a detailed and integrated Asset Management Plan ("AMP") that identifies key distribution system maintenance and replacement programs. (The AMP is addressed at Exhibit 2 Tab 2 Schedule 2 and is attached in its entirety at Exhibit 2 Tab 2 Schedule 2 Appendix 1). These programs have been developed utilizing key asset metrics, including age and performance, in order to prioritize which system components require maintenance or full replacement. Additionally, the collection of detailed distribution system component information will deepen Enersource's ability to perform predictive analytics to estimate which components may fail in the near term and implement maintenance programs to reduce outage times.

Timely and effective rate applications secure appropriate revenue streams and cash generation for Enersource and ensure business stability in today's challenging economic and regulatory climate.

Corporate Relations

The strategic focus of the Corporate Relations department is to develop and enhance the Corporation's brand and reputation and provide marketing and communications support to the Corporation as it relates to fulfilling their business requirements and strategic objectives.

Business principals driving the rebrand include:

- Exceptional customer service through effective communication and expansion of self-service billing management;
- High levels of employee engagement and delivery of value proposition to bring internal and external customers more than energy; and,
- Business activities are integrated into strategic community support which bolsters the value proposition.

Government Relations' efforts will be focused on policy matters regarding the implementation of the Ontario Government's *Green Energy and Green Economy Act,* Time-Of-Use ("TOU") rates implementation and other matters arising as a result of government decision and policy making. Stakeholder relations will be employed to enhance the brand reputation among external stakeholders at the local level.

There continues to be ongoing efforts to increase the impact and presence with the Mississauga Board of Trade and Mississauga businesses in general to support and promote conservation and demand management programs, individual suite metering for condominiums, and enhance brand presence among small and large businesses. EC will also continue its involvement with the Partners in Project Green Committees in the creation of an eco-business zone around the Toronto Airport.

The Corporation operates in an environment where the perception of energy companies, and the industry overall, carries a lot of negative connotations, mainly due to the increasing cost of energy. Public and media relations are important channels for addressing or dispelling some of these opinions, but can also be used to promote a positive corporate image across all target audiences. In particular, it is a great way to showcase all of the good things that the Corporation does within the community.

Managing a website for a customer base of approximately 195,000 is a key communication tool. Recent data indicates that the website currently receives over 15,000 visits per month, from over 10,000 unique visitors. On average, each visit involves three page views, with time spent on the site around three minutes. Approximately 57% of visitors arrive via a search engine, while 32% is direct traffic. Aside from the landing page, the top three pages visited are: Career Opportunities, Understanding Your Bill and the My Home section page. Over the next few years, the expectation is that the volume of mobile traffic will increase exponentially from the current 5% and that companies like EC need to be mobile ready for not only informational purposes but billing purposes as well.

For companies, social media can be a powerful platform from which to communicate with customers and other stakeholders, increasing their engagement with the brand in a cost effective manner. In the case of Enersource, a good example of social media use is to inform subscribers about planned outages, or provide updates on any other unplanned situations, and provide regular conservation tips with a local perspective.

Enersource's Twitter presence began in January, 2010. At the end of 2011, there were over 620 Followers, and over 950 Tweets posted. This stakeholder and customer base on social media is expected to grow as will expectations on frequency and quality of information.

The Corporate Relations department is also responsible for employee and employer engagement. One of the Corporation's most critical audiences is its own employees. Without a fully-engaged workforce that is attuned to the overall corporate vision, mission and brand values, its business objectives cannot be achieved to the required levels. It is equally important to make sure existing employees are retained, and that prospective employees are informed of the positive aspects of the Corporation's work environment. In a time where it is imperative to attract skilled professionals and tradespeople, the Corporation needs to be actively attracting future employees through earned and paid public relations.

It is always important to engage customers and maintain regular contact. Newsletters are a great vehicle in which to augment a wider communication plan. They create an opportunity to build the brand, delivering crucial information that will assist the overall corporate goals, providing interesting articles that will increase engagement, and passing on conservation tips or advice that will be mutually beneficial. Most important, they enable customers to remain connected, and build the levels of trust and credibility that Enersource is seeking to achieve. Newsletter distribution is no longer just a paper exercise. Customers expect choice and are now produced as electronic newsletters ("e-newsletters") distributed via email, and printed versions that are handed out through various methods. For residential customers, bill inserts are also mailed to the entire customer base encouraging those to sign-up for future e-newsletters, as well as a pop-up banner for electronic billing ("e-billing") customers.

In order to achieve the above, the Corporate Relations team had an increase in staff in 2008, and forecasts a complement of four for 2011 and beyond. Staffing includes a Director, Senior Communications Specialist, Marketing and Communications Specialist, and Digital Communications Specialist.

Internal Audit and Enterprise Risk

Internal Audit and Enterprise Risk manages the ongoing assessment and reporting of all entity risks, including environmental and business continuity risks, faced by the Corporation as well as oversees the Internal Audit function.

The assessment and reporting of risks is formalized within the scope of an Enterprise Risk Management system which:

- Establishes a formal policy for EC including a definition of the risk context, the strengths and weaknesses, the opportunities and threats and the various stakeholders;
- Identifies entity-specific significant hazards, as well as financial, operational, and strategic risks;
- Analyzes, quantifies, and prioritizes risks, and identifies measurement statistics; and,
- Identifies management responses to risks and mitigation strategies, and assigns owners for each risk.

The risk inventory and management mitigation responses are reported to the Audit Committee on a periodic basis each year.

Environmental assessments, which began in 2006, are conducted on Enersource's owned assets and properties. The administration office and operations centre at 3240 Mavis Road as well as 33 out of 66 substations have already been assessed or await a final environmental report. Currently, remediation is required at two substation properties. A long term environmental management system ("EMS") was developed in 2010 and since then, EC has met the ISO 14001 standards in each annual audit. These standards require a supporting policy manual, including procedures, occurrence data collection, forms, and training programs.

A Business Continuity Plan has also been detailed at a departmental level. In 2010, plans were completed for eight departments as well as a revised overall corporate emergency plan. In 2011, a test was performed where a rented on-call emergency trailer was delivered to EC's current Business Continuity Management ("BCM") centre, complete with computers and network functionality for the various departments required in an emergency. All of the required departments were able to access their applications within 24 hours after the start of the test.

The mission of the Internal Audit department is to provide independent and objective assurance designed to strengthen the Corporation's internal control structure, safeguard the Corporation's assets, examine the efficiency and effectiveness of operations, identify opportunities for process and control improvements, ensure the reliability of financial reporting, monitor compliance with laws and regulations, and share best practices throughout the Corporation. Internal Audit accomplishes its objectives by bringing a systematic, disciplined approach to evaluate and improve the effectiveness of risk management, internal controls, and governance processes.

Up to mid-2008, Internal Audit focused on a project enabling the Corporation to meet the certification requirements of Multilateral Instrument 52-109. As part of those requirements, the CEO and CFO certified that controls were designed, and that the controls operated as designed. In 2008 the regulations were modified and EC was listed as a "Venture Issuer" which meant that the certification requirements were no longer mandatory. Recognizing the operational and internal control benefits of the project, EC's Internal Audit continues to ensure compliance going forward by:

- Identifying any new significant financial reporting elements and processes that have a direct impact on the financial statements of the Corporation;
- Updating documentation and evaluation of:
    - Disclosure controls and procedures;
    - Process and controls associated with financial reporting;
    - Entity-level controls; and
    - Information technology controls;
- Communicating and resolving any issues stemming from the evaluations; and,
- Managing the certification project to ensure appropriate project documentation, status monitoring, reporting, and sign-off.

Finance

The Finance business unit supports Enersource and affiliates with financial, accounting, and rate-setting expertise. Strategically, this area has focused on enhanced service delivery, supporting regulatory policy influence, and the pursuit of growth opportunities.

Beginning in late 2008, the Finance business unit began EC's initial assessment and development of a transitional plan to International Financial Reporting Standards ("IFRS"). EC's IFRS conversion project consisted of four phases: awareness, assessment, design, and implementation.

The awareness and assessment phases were completed in 2009 and included training of key stakeholders, identification of significant impacts on systems, processes, and internal controls, and completion of a detailed systematic gap analysis of the accounting and reporting differences between Canadian GAAP and IFRS.

The design and implementation of IFRS occurred between 2009 and the first quarter of 2012. The Finance department saw an overall increase in staffing levels due to IFRS. Two non-union staff members have been hired since 2008 to ensure on-going compliance with IFRS, and additional accounting and reporting requirements.

The Finance department's main responsibility is to oversee the integrity and compliance with accounting policies and procedures, external financial reporting, and compiling information for the annual RRR filings. Specifically, the Finance department or business unit makes recommendations regarding financial objectives, plans, and risk management strategies to other areas and departments within the Corporation. It is also accountable for documenting, creating and submitting all financial information to the Audit and Finance Committees and filing quarterly financial statements with EC's Trustee.

In addition, the Finance department reviews capitalization and operational practices and procedures and assists other departments with their budgets, forecasts, and reporting of the actual results achieved in each area. The Finance department includes the following main groups:

- Treasury;
- Capital Management;
- Revenue Assurance and Rates;
- Payroll; and
- Reporting and Budgeting.

Human Resources

A comprehensive Human Resources strategy was re-developed in 2011. The formalized plan relies on the full engagement and alignment of all employees to

fulfill the execution of the corporate strategic plan. The strategy over the next three years builds on continued positioning of the Corporation as an employer of choice in the minds of our employees and within the external community, and the enhancement of employee capability.

EC has implemented a formal management succession planning process across the Corporation to ensure human capital requirements are addressed. Management succession planning is being treated as a critical priority to sustain the success of the Corporation as it continues to experience the retirement exodus of the boomer generation.

EC is now focused on supervisory requirements and refining its workforce analytics to ensure that Enersource will have sufficient resources in its trades talent pipeline over the next few years. Enersource currently has 21 apprentices being developed for outside trades and technical roles. EC will need to continue to do advance hiring, recognizing that there is a structured four-year training path to develop the competencies associated with these positions. EC hires and trains up to six overhead/underground apprentices each year, and will continue to do so for the next several years to off-set a large number of retiring employees.

An Assess Competency System was also introduced in 2011. The idea behind this new system is to leverage existing opportunities and to build an integrated human resources framework that links and optimizes recruitment, selection, training and development, performance evaluation, and succession planning.

EC's approach to its relationship with the International Brotherhood of Electrical Workers ("IBEW") is to remain positive and proactive while recognizing that it is management's obligation to control costs and achieve productivity enhancements

within a safe work environment. Preparations for the negotiation of the collective agreement, which expires on March 31, 2014, will commence early in 2013.

Purchasing and Legal

The Purchasing and Legal business units provide EC with procurement services according to EC's purchasing policy, legal advice, and regulatory assistance, when required.

The procurement process includes analysis and recommendations which are made for the best overall value to EC and is provided through competitive market review and the negotiation process. The Corporation's purchasing strategy is also addressed in Exhibit 4 Tab 5 Schedule 1.

The Purchasing business unit assists other business units to complete bidding processes and requests for proposals ("RFPs"), including sourcing suppliers, writing the RFP in conjunction with the internal business owner, administrating the process during bidding, evaluating bids and recommending awards.

The Legal business unit also assists EC with corporate governance issues and other legal matters.

Table 1: Enersource Corporation Employee Count by Year

Business Unit	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
CEO and Corporate Relations	10	12	11	12	12	12
Safety (Moved to Enersource in 2011)	2	2	2	-	-	-
Finance, Internal Audit & Risk	28	29	31	32	32	32
Purchasing	5	5	5	5	5	5
Legal	2	2	1	1	1	1
Human Resources	3	3	3	3	3	3
EC Ending Headcount	50	53	53	53	52	52

Table 2: Enersource Corporation Employee Type by Year

Employee Type	2008 Rates	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Inside (Union)	16	16	16	15	15	15
Non-Union	30	33	32	33	33	33
Executive Non-Union	4	4	4	5	5	5

Overall, EC has seen a net increase of two positions since 2008. EC transferred its Health & Safety staff and one Finance application specialist to Enersource.

Finance added two non-union staff members to ensure on-going compliance with IFRS. In 2011, a Vice President position was transferred from Enersource to EC, in Finance. In addition, to ensure EC continually meets ISO 14001 standards, a new non-union Risk Advisor staff member was hired in 2010. In 2008, the

Internal Auditor non-union position was converted from a contract position to a permanent position.

EC also added two non-union Corporate Relations staff members that were offset by a reduction of two other non-union staff: a staff lawyer in late 2007 and one executive assistant position at the end of 2011.

EC does not anticipate the need for any new resources in the 2012 Bridge or 2013 Test Year.

Table 3 - Operating Costs by Type and by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Salary	$ 4,058	$3,970	$4,532	$ 4,475	$ 4,065	$ 4,316	$ 4,554
Benefits	1,484	1,450	1,419	1,767	1,977	1,931	2,084
Audit, Banking & Insurance	1,709	1,680	1,785	1,709	1,714	1,578	1,917
Communications & Customer Relations	227	239	328	338	621	423	419
Employee Development	317	396	232	232	213	243	244
Memberships & Subscriptions	164	140	160	131	134	130	133
Safety Related Costs	363	209	240	255	-	-	-
Supplies, Conferences, Travel	164	111	70	109	77	126	130
Directors Honoraria	186	132	132	132	141	138	140
Social Responsibility	55	99	76	89	102	105	105
Corporate overhead	1,297	981	815	1,101	1,099	1,514	1,583
Legal	130	570	391	503	254	345	335
IFRS Deferral	-	-	(491)	(608)	(391)	-	-
Total EC Operating Costs	$10,154	$9,977	$9,689	$10,233	$10,006	$10,849	$11,644
Corporate Allocation (per Appendix 2-L)	8,546	8,358	8,842	9,721	9,506	10,131	10,874

In summary, the increase in costs is attributable to:

- Increased staff levels (due to ongoing ISO 14001, and IFRS compliance costs);
- Increased average compensation levels;
- Significant increase in employee benefits (mainly due to OMERS pension-related costs);
- Increase in audit (IFRS), banking, and insurance fees (EC received a one-time reciprocal reduction in 2012);
- IFRS transition costs were deferred between 2009-2011;
- Transferred employees from Enersource to EC (application specialist and one VP position);
- Increase in corporate overhead expenses relating to facilities, ISTS, and asset usage charges from Enersource.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2008 RATES

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	209,560	188,604	90.0%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	2,290,109	2,061,098	90.0%
Enersource Corporation	Enersource Hydro	Safety	Cost	726,830	654,147	90.0%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	4,054,753	3,324,897	82.0%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	483,615	206,911	42.8%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	1,091,672	1,004,338	92.0%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	1,297,000	1,106,009	85.3%
Total				10,153,539	8,546,004	83.8%
			Check	**10,153,539**	**8,546,004**	
			Difference	-	- 0.00	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2008

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	143,026	128,723	90.0%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	2,636,611	2,372,950	90.0%
Enersource Corporation	Enersource Hydro	Safety	Cost	663,654	597,289	90.0%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	3,656,984	2,998,727	82.0%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	665,773	291,590	43.8%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	1,230,192	1,131,777	92.0%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	981,097	836,625	85.3%
Total				9,977,338	8,357,681	83.8%
			Check	**9,977,338**	**8,357,681**	
			Difference	-	- 0.00	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2009

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	146,067	131,461	90.0%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	3,071,190	2,781,688	90.6%
Enersource Corporation	Enersource Hydro	Safety	Cost	630,844	605,610	96.0%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	3,485,259	3,140,697	90.1%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	503,440	453,096	90.0%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	1,037,006	995,526	96.0%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	815,375	733,837	90.0%
Total				9,689,181	8,841,915	91.3%
			Check	**9,689,181**	**8,841,915**	
			Difference	-	0.00	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2010

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	139,938	132,941	95.0%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	2,680,649	2,546,617	95.0%
Enersource Corporation	Enersource Hydro	Safety	Cost	610,330	579,814	95.0%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	4,323,048	4,106,896	95.0%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	631,843	600,250	95.0%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	746,728	709,392	95.0%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	1,100,507	1,045,480	95.0%
Total				10,233,043	9,721,391	95.0%
			Check	**10,233,043**	**9,721,391**	
			Difference	0.00	0.00	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2011

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	163,980	155,781	95.0%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	2,578,384	2,449,465	95.0%
Enersource Corporation	Enersource Hydro	Safety	Cost	-	-	0.0%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	5,014,812	4,764,072	95.0%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	366,900	348,555	95.0%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	783,319	744,153	95.0%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	1,099,218	1,044,257	95.0%
Total				10,006,613	9,506,283	95.0%
			Check	**10,006,613**	**9,506,283**	
			Difference	-	-	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2012

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	156,234	145,767	93.3%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	2,541,837	2,371,534	93.3%
Enersource Corporation	Enersource Hydro	Safety	Cost	-	-	93.3%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	5,359,819	5,000,711	93.3%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	481,912	449,624	93.3%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	795,032	750,510	94.4%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	1,514,339	1,412,878	93.3%
Total				10,849,173	10,131,024	93.4%
			Check	**10,849,173**	**10,131,024**	
			Difference	-	-	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2013

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	158,224	147,623	93.3%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	2,638,613	2,461,826	93.3%
Enersource Corporation	Enersource Hydro	Safety	Cost	-	-	93.3%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	5,892,846	5,498,025	93.3%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	493,039	460,006	93.3%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	878,262	829,079	94.4%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	1,583,394	1,477,308	93.3%
Total				11,644,378	10,873,866	93.4%
			Check	**11,644,378**	**10,873,666**	
			Difference	-	-	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

Appendix 2-L
Shared Services/Corporate Cost Allocation

Year: 2014

Name of Company		Service Offered	Pricing Methdology	Total Cost for the Service	Regulated Cost for the Service	Percentage Allocation
From	**To**			**$**	**$**	**%**
Enersource Corporation	Enersource Hydro	Board of Directors	Cost	160,253	149,516	93.3%
Enersource Corporation	Enersource Hydro	CEO office and Government Relations	Cost	2,695,323	2,514,736	93.3%
Enersource Corporation	Enersource Hydro	Safety	Cost	-	-	93.3%
Enersource Corporation	Enersource Hydro	Finance, Internal Audit & Risk	Cost	5,987,561	5,586,394	93.3%
Enersource Corporation	Enersource Hydro	Legal and Purchasing	Cost	501,078	467,506	93.3%
Enersource Corporation	Enersource Hydro	Human Resources	Cost	888,459	838,705	94.4%
Enersource Corporation	Enersource Hydro	Other Operating Costs	Cost	1,527,700	1,425,345	93.3%
Total				11,760,374	10,982,202	93.4%
			Check	**11,760,374**	**10,982,202**	
			Difference	-	-	

Note:

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

ENERSOURCE TECHNOLOGIES INC.

("Service Provider")

and

ENERSOURCE HYDRO MISSISSAUGA INC.

("Customer")

SERVICES AGREEMENT

Effective as of

January 1, 2011

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made this 1st day of January, 2011 (the "Effective Date").

BETWEEN:

ENERSOURCE TECHNOLOGIES INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"SERVICE PROVIDER")**

and

ENERSOURCE HYDRO MISSISSAUGA INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"CUSTOMER")**

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. Each of SERVICE PROVIDER and CUSTOMER are subsidiaries of Enersource Corporation, as defined in the *Business Corporations Act* (Ontario);

3. CUSTOMER carries on the business of distributing electricity within the City of Mississauga;

4. SERVICE PROVIDER has agreed to provide certain services to CUSTOMER on the terms set forth in this Agreement;

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below:

(a) **"Agreement", "hereto", "hereof", "herein", "hereby", "hereunder"** and similar expressions mean this Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the City of Mississauga;

(c) **"Claim"** has the meaning ascribed to such term in **Section 4.4**;

(d) **"Confidential Information"** means information CUSTOMER has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Default"** means in respect of Defaulting Party, an event set out in **Section 8.1;**

(f) **"Defaulting Party"** has the meaning ascribed to such term in **Section 8.1;**

(g) **"Effective Date"** means the date first written above;

(h) **"Event of Default"** means a Default, the notice and cure periods (if any) respecting which have expired;

(i) **"Force Majeure Event"** has the meaning ascribed to such term in **Section 9.1;**

(j) **"IESO"** means the Independent Electricity System Operator, or its successor;

(k) **"OEB"** means the Ontario Energy Board, or its successor;

(l) **"Law"** means any law, rule, regulation, code, order, writ, judgment, decree or other legal or regulatory determination by a court, regulatory agency, including the OEB and IESO, or governmental authority of competent jurisdiction;

(m) **"Party"** means a party to this Agreement and "Parties" means every party;

(n) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(o) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(p) **"Services"** has the meaning ascribed thereto in **Section 3.1** of this Agreement;

(q) **"Term"** has the meaning ascribed thereto in **Section 2.1** of this Agreement; and

(r) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by SERVICE PROVIDER on behalf of CUSTOMER in connection with providing the Services or incurred by CUSTOMER's Personnel while providing Services under this Agreement paid by SERVICE PROVIDER.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, Subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings;

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2
TERM

2.1 Term

This Agreement shall commence on the date set forth above and, subject to earlier termination as provided for in this Agreement, continue in effect for a term of one year, terminating on December 31, 2011 (the "Term"). The Term shall thereafter be automatically extended for successive additional one (1) year periods (each an "Extension Term") unless either party terminates this Agreement by no less than sixty (60) days written notice to the other.

ARTICLE 3
SERVICE PROVIDER SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, SERVICE PROVIDER shall provide, or cause to be provided, to CUSTOMER the services set out in **Schedule "A"** (collectively the "**Services**") at the rates set out in **Schedule "B"**, and such other services as CUSTOMER may request and SERVICE PROVIDER may agree to provide from time to time.

3.2 Performance Standards

(a) SERVICE PROVIDER shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) SERVICE PROVIDER shall make all reasonable efforts to meet or exceed performance measures established by the OEB.

(c) All SERVICE PROVIDER's Personnel with responsibility for carrying out SERVICE PROVIDER's responsibilities hereunder shall be familiar with CUSTOMER's electricity service area and local needs. All customer, billing, accounting and other records kept in connection with this Agreement shall be readily available to CUSTOMER in an office within the CUSTOMER's service area.

3.3 Changes

CUSTOMER and SERVICE PROVIDER may, from time to time, agree to modifications to a Service agreed to be provided hereunder by negotiating appropriate changes to the descriptions of the Service and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

3.4 General SERVICE PROVIDER Covenants

(a) SERVICE PROVIDER shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and SERVICE PROVIDER shall, when requested, provide CUSTOMER with adequate evidence of its compliance with this **Section 3.4;**

(b) SERVICE PROVIDER shall comply, while on the premises used by CUSTOMER, with all the rules and regulations of CUSTOMER from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) All SERVICE PROVIDER's Personnel with responsibility for the provision of Services shall be familiar with the CUSTOMER's electricity service area.

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall negotiate in good faith to develop a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4
MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

No Personnel of the SERVICE PROVIDER shall have access to any Confidential Information in the possession of the CUSTOMER, except for purposes related to the Services and in compliance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the OEB.

4.2 Maintain Records

The CUSTOMER and SERVICE PROVIDER shall maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

CUSTOMER shall promptly give written notice to SERVICE PROVIDER of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of CUSTOMER, the number of employees of CUSTOMER, or any efforts relating to the organization of or collective bargaining by employees of CUSTOMER, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

CUSTOMER shall promptly give written notice to SERVICE PROVIDER, and SERVICE PROVIDER shall promptly give notice to CUSTOMER, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by CUSTOMER or SERVICE PROVIDER (whether or not any such Claim is covered by insurance) in respect of its own operations of which either of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5
FEES AND COSTS

5.1 Fees

CUSTOMER shall forthwith pay to SERVICE PROVIDER the fees and charges set out in **Schedule "B"** upon being advised such fees are due.

5.2 Taxes

In addition to the fees, CUSTOMER shall pay to SERVICE PROVIDER an amount equal to any and all Harmonized Sales Taxes, value-added taxes or any other taxes (excluding income taxes) properly exigible on the supply of Services provided by a third party under this Agreement.

5.3 Late Payment

If CUSTOMER fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at the rate of one and one half percent (1 ½ %) per month.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of SERVICE PROVIDER

SERVICE PROVIDER represents and warrants to CUSTOMER as follows and acknowledges that CUSTOMER is relying on such representations and warranties in connection herewith:

(a) SERVICE PROVIDER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of SERVICE PROVIDER, enforceable against SERVICE PROVIDER by CUSTOMER in accordance with its terms; and

(d) SERVICE PROVIDER has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of CUSTOMER

CUSTOMER represents and warrants to SERVICE PROVIDER as follows and acknowledges that SERVICE PROVIDER is relying on such representations and warranties in connection herewith:

(a) CUSTOMER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario, licensed by the OEB, and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of CUSTOMER, enforceable against CUSTOMER by SERVICE PROVIDER in accordance with its terms.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification

(a) CUSTOMER shall indemnify, defend and hold harmless SERVICE PROVIDER, its' officers, directors, and employees (each a **"SERVICE PROVIDER Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"**), asserted against or suffered by any SERVICE PROVIDER Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(b) SERVICE PROVIDER shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the SERVICE PROVIDER Indemnities that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) CUSTOMER agrees that SERVICE PROVIDER's liability, if any, to CUSTOMER or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of SERVICE PROVIDER in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of SERVICE PROVIDER in the provision of the Services and shall not exceed an amount equal to the total amount paid by CUSTOMER to SERVICE PROVIDER under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) SERVICE PROVIDER shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that SERVICE PROVIDER shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on CUSTOMER, and CUSTOMER agrees to indemnify and hold harmless SERVICE PROVIDER from any such sanctions fines, penalties or similar obligations.

ARTICLE 8
DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party")** under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set forth:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9
GENERAL

9.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a **"Force Majeure Event").**

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

9.2 Dispute Resolution

If any dispute arising in relation to the application or interpretation of this Agreement (a **"dispute")** which cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by CUSTOMER, one appointed by SERVICE PROVIDER, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the dispute and to render a decision. The arbitrators shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the Parties.

9.3 Assignment

Neither Party shall, without the written approval of the other Party hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

9.4 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) if to SERVICE PROVIDER,

Enersource Technologies Inc.
3240 Mavis Road
Mississauga, Ontario
LSC 3K1

Attn: President
Fax: (905) 566-2737

(b) if to CUSTOMER,

Enersource Hydro Mississauga Inc.
3240 Mavis Road
Mississauga, Ontario
L5C 3K1

Attn: Chief Operating Officer
Fax: (905) 566-2737

and shall be personally delivered or shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

9.5 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

9.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

9.7 Entire Agreement

This Agreement supersedes any prior agreement between the parties, and constitutes the entire Agreement between the Parties with respect to the Services and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

9.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

9.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9.10 Survival

The terms of **Article 4** and **Article 7** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

9.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

9.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

ENERSOURCE TECHNOLOGIES INC.

Per: _____
Name: Craig Fleming
Title: President
I have authority to bind the Corporation

Per: _____
Name: Norman Wolff
Title: Secretary
I have authority to bind the Corporation

ENERSOURCE HYDRO MISSISSAUGA INC.

Per: _____
Name: Dan J. Pastoric
Title: Executive Vice-President & Chief Operating Officer
I have authority to bind the Corporation

Per: _____
Name: Raymond Rauber
Title: Vice-President, Engineering & Operations
I have authority to bind the Corporation

SCHEDULE "A"
Description of Services

1. **"Technologies Services"** includes the provision of technological solutions to business issues, the provisions of machines and consulting thereon.

2. **"Information Technology Services"** includes hardware, software services and consulting thereon.

3. **"Telephone Services"** includes the processing of and the provision of telephone services, telephones, and hosted telephone solutions from third parties.

4. "**Other**" includes services other than those specifically enumerated above and that are requested and provided from time to time under Section 3.1.

SCHEDULE "B"
Fees for Services

	SERVICES	FEES
1.	**Technologies Services**	Fees shall be calculated and charged on a Cost basis.
2.	**Information Technology Services**	Fees shall be calculated and charged on a Cost basis.
3.	**Telephone Services**	Fees shall be calculated and charged on a Cost basis.
4.	**Other**	Fees shall be calculated and charged on a Cost basis.

NOTES:

1. "**Cost**" means CUSTOMER's actual amounts incurred by SERVICE PROVIDER in respect of the Services.

2. Fees that are calculated and charged on a Cost basis are in accordance with actual costs incurred by SERVICE PROVIDER.

ENERSOURCE CORPORATION

("Service Provider")

and

ENERSOURCE HYDRO MISSISSAUGA INC.

("Customer")

SERVICES AGREEMENT

Effective as of

January 1, 2011

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made this 1st day of January, 2011 (the "Effective Date").

BETWEEN:

ENERSOURCE CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"SERVICE PROVIDER")**

and

ENERSOURCE HYDRO MISSISSAUGA INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"CUSTOMER")**

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. CUSTOMER carries on the business of distributing electricity within the City of Mississauga;

3. SERVICE PROVIDER has agreed to provide certain services to CUSTOMER on the terms set forth in this Agreement;

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below:

(a) **"Agreement", "hereto", "hereof", "herein", "hereby", "hereunder"** and similar expressions mean this Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the City of Mississauga;

(c) **"Claim"** has the meaning ascribed to such term in **Section 4.4**;

(d) **"Confidential Information"** means information CUSTOMER has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Default"** means in respect of Defaulting Party, an event set out in **Section 8.1;**

(f) **"Defaulting Party"** has the meaning ascribed to such term in **Section 8.1;**

(g) **"Effective Date"** means the date first written above;

(h) **"Event of Default"** means a Default, the notice and cure periods (if any) respecting which have expired;

(i) **"Force Majeure Event"** has the meaning ascribed to such term in **Section 9.1;**

(j) **"IESO"** means the Independent Electricity System Operator, or its successor;

(k) **"OEB"** means the Ontario Energy Board, or its successor;

(l) **"Law"** means any law, rule, regulation, code, order, writ, judgment, decree or other legal or regulatory determination by a court, regulatory agency, including the OEB and IESO, or governmental authority of competent jurisdiction;

(m) **"Party"** means a party to this Agreement and "Parties" means every party;

(n) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(o) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(p) **"Services"** has the meaning ascribed thereto in **Section 3.1** of this Agreement;

(q) **"Term"** has the meaning ascribed thereto in **Section 2.1** of this Agreement; and

(r) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by SERVICE PROVIDER on behalf of CUSTOMER in connection with providing the Services or incurred by CUSTOMER's Personnel while providing Services under this Agreement paid by SERVICE PROVIDER.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, Subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings;

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2
TERM

2.1 Term

This Agreement shall commence on the date set forth above and, subject to earlier termination as provided for in this Agreement, continue in effect for a term of one year, terminating on December 31, 2011 (the "Term"). The Term shall thereafter be automatically extended for successive additional one (1) year periods (each an "Extension Term") unless either party terminates this Agreement by no less than sixty (60) days written notice to the other.

ARTICLE 3
SERVICE PROVIDER SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, SERVICE PROVIDER shall provide, or cause to be provided, to CUSTOMER the services set out in **Schedule "A"** (collectively the "**Services**") at the rates set out in **Schedule "B"**, and such other services as CUSTOMER may request and SERVICE PROVIDER may agree to provide from time to time.

3.2 Performance Standards

(a) SERVICE PROVIDER shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) SERVICE PROVIDER shall make all reasonable efforts to meet or exceed performance measures established by the OEB.

(c) All SERVICE PROVIDER's Personnel with responsibility for carrying out SERVICE PROVIDER's responsibilities hereunder shall be familiar with CUSTOMER's electricity service area and local needs. All customer, billing, accounting and other records kept in connection with this Agreement shall be readily available to CUSTOMER in an office within the CUSTOMER's service area. All call centre and phone-answering services shall be performed by persons who have sufficient knowledge of local developments, government and geography in the CUSTOMER's service area so as to appropriately represent CUSTOMER's role as a local municipally controlled provider of electricity distribution services.

3.3 Changes

CUSTOMER and SERVICE PROVIDER may, from time to time, agree to modifications to a Service agreed to be provided hereunder by negotiating appropriate changes to the descriptions of the Service and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

3.4 General SERVICE PROVIDER Covenants

(a) SERVICE PROVIDER shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and SERVICE PROVIDER shall, when requested, provide CUSTOMER with adequate evidence of its compliance with this **Section 3.4;**

(b) SERVICE PROVIDER shall comply, while on the premises used by CUSTOMER, with all the rules and regulations of CUSTOMER from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) All SERVICE PROVIDER's Personnel with responsibility for the provision of Services shall be familiar with the CUSTOMER electricity service area.

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall negotiate in good faith to develop a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4
MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

No Personnel of the SERVICE PROVIDER shall have access to any Confidential Information in the possession of the CUSTOMER, except for purposes related to the Services and in compliance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the OEB.

4.2 Maintain Records

The CUSTOMER and SERVICE PROVIDER shall maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

CUSTOMER shall promptly give written notice to SERVICE PROVIDER of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of CUSTOMER, the number of employees of CUSTOMER, or any efforts relating to the organization of or collective bargaining by employees of CUSTOMER, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

CUSTOMER shall promptly give written notice to SERVICE PROVIDER, and SERVICE PROVIDER shall promptly give notice to CUSTOMER, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by CUSTOMER or SERVICE PROVIDER (whether or not any such Claim is covered by insurance) in respect of its own operations of which either of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5
FEES AND COSTS

5.1 Fees

CUSTOMER shall forthwith pay to SERVICE PROVIDER the fees and charges set out in **Schedule "B"** upon being advised such fees are due.

5.2 Taxes

In addition to the fees, CUSTOMER shall pay to SERVICE PROVIDER an amount equal to any and all Harmonized Sales Taxes, value-added taxes or any other taxes (excluding income taxes) properly exigible on the supply of Services provided by a third party under this Agreement.

5.3 Late Payment

If CUSTOMER fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at the rate of one and one half percent (1 ½ %) per month.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of SERVICE PROVIDER

SERVICE PROVIDER represents and warrants to CUSTOMER as follows and acknowledges that CUSTOMER is relying on such representations and warranties in connection herewith:

(a) SERVICE PROVIDER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of SERVICE PROVIDER, enforceable against SERVICE PROVIDER by CUSTOMER in accordance with its terms; and

(d) SERVICE PROVIDER has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of CUSTOMER

CUSTOMER represents and warrants to SERVICE PROVIDER as follows and acknowledges that SERVICE PROVIDER is relying on such representations and warranties in connection herewith:

(a) CUSTOMER is a corporation, duly organized, validly existing and in good standing under the laws of the Province of Ontario, licensed by the OEB and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of CUSTOMER, enforceable against CUSTOMER by SERVICE PROVIDER in accordance with its terms.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification

(a) CUSTOMER shall indemnify, defend and hold harmless SERVICE PROVIDER, its' officers, directors, and employees (each a **"SERVICE PROVIDER Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"**), asserted against or suffered by any SERVICE PROVIDER Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(b) SERVICE PROVIDER shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the SERVICE PROVIDER Indemnities that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) CUSTOMER agrees that SERVICE PROVIDER's liability, if any, to CUSTOMER or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of SERVICE PROVIDER in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of SERVICE PROVIDER in the provision of the Services and shall not exceed an amount equal to the total amount paid by CUSTOMER to SERVICE PROVIDER under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) SERVICE PROVIDER shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that SERVICE PROVIDER shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on CUSTOMER, and CUSTOMER agrees to indemnify and hold harmless SERVICE PROVIDER from any such sanctions fines, penalties or similar obligations.

ARTICLE 8
DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party")** under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set forth:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9
GENERAL

9.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a **"Force Majeure Event").**

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

9.2 Dispute Resolution

If any dispute arising in relation to the application or interpretation of this Agreement (a **"dispute")** which cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by CUSTOMER, one appointed by SERVICE PROVIDER, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the dispute and to render a decision. The arbitrators shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the Parties.

9.3 Assignment

Neither Party shall, without the written approval of the other Party hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

9.4 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) if to SERVICE PROVIDER,

Enersource Corporation
3240 Mavis Road
Mississauga, Ontario
LSC 3K1

Attn: President & CEO
Fax: (905) 566-2737

(b) if to CUSTOMER,

Enersource Hydro Mississauga Inc.
3240 Mavis Road
Mississauga, Ontario
L5C 3K1

Attn: Chief Operating Officer
Fax: (905) 566-2737

and shall be personally delivered or shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

9.5 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

9.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

9.7 Entire Agreement

This Agreement supersedes any prior agreement between the parties, and constitutes the entire Agreement between the Parties with respect to the Services and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

9.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

9.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9.10 Survival

The terms of **Article 4** and **Article 7** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

9.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

9.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

ENERSOURCE CORPORATION

Per: _____
Name: Craig Fleming
Title: President and Chief Executive Officer
I have authority to bind the Corporation

Per: _____
Name: Norman Wolff
Title: Executive Vice President & Chief Financial Officer
I have authority to bind the Corporation

ENERSOURCE HYDRO MISSISSAGUA INC.

Per: _____
Name: Dan Pastoric
Title: Executive Vice-President & Chief Operating Officer
I have authority to bind the Corporation

Per: _____
Name: Raymond Rauber
Title: Vice-President, Engineering & Operations
I have authority to bind the Corporation

SCHEDULE "A"

Description of Services

1. **"Finance Services"** include treasury, controllership, rate setting and audit.

(a) Treasury services include financing, i.e.: issuance and management of debt, operating line of credit, cash flow management and investment of funds, banking, financial guarantees, i.e.: letters of credit, bonds, prudentials, payroll services, accounts payable services, office services, obtaining and maintaining credit ratings, trustee reporting, management of customer deposits, interest and T5 reporting, taxation (PILS), HST or tax remittances and corporate VISA card.

(b) Controllership services include financial systems, financial processes, policies and procedures, financial controls and compliance, financial reporting and analysis, annual budgets, financial operations, billing, collecting, capitalization and depreciation, WIP and inventory, labour charging, allocations and burdens, managing external audit, liability, fleet, facilities, OEB reporting, incentive plan reporting, billing system quality control.

(c) Rate setting services include providing analytical services and recommendations in regards to rate development and the regulatory filings, submissions and attendance at hearings as necessary.

2. **"Human Resources Services"** include resource development and workforce sustainment including recruitment, compensation and benefits, employee relations, labour relations, training and development, policy development, and performance management and organization development.

3. **"Procurement Services"** include the preparation of tender documents and organization of the tendering process, obtaining quotes for purchases and sourcing suppliers, processing of internal requisitions, preparation of purchase orders, stocking of inventory for planned and unplanned service orders and determining inventory levels.

4. **"Corporate Relation Services"** include the preparation and delivery of broad-based and strategic communications to the general public and specific target audiences, including written publications such as media releases and annual reports and community relations activities and events.

5. **"Executive Management Services"** includes the provision of executive management and advice in the running of CUSTOMER.

6. "**Corporate Governance Services**" include the provision of strategic direction and leadership, and the governance of the company's activities, which include supporting its board of directors, board committees and executive management, and legal services.

7. **"Internal Audit and Enterprise Risk Services"** include assessing and reporting of all entity risks, including environmental and business continuity risks and providing independent and objective assurance designed to strengthen the organization's internal control structure and safeguard the company's assets.

8. **"Legal Services"** include directing the legal affairs including commercial, corporate, contractual, legislative and regulatory litigation and legal advice.

9. "**Other Services**" include services other than those specifically enumerated above and that are requested and provided from time to time under Section 3.1.

SCHEDULE "B"
Fees for Services

	SERVICES	FEES
1.	**Finance Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
2.	**Human Resources Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Head Count.
3.	**Procurement Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
4.	**Corporate Relations Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
5.	**Corporate Governance Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
6.	**Internal Audit and Enterprise Risk Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
7.	**Legal Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
8.	**Other Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.

NOTES:

1. "Proportionate Share of Operating Revenues" means the proportion that the budgeted operating revenues (exclusive of investment revenues) of CUSTOMER bears to the total budgeted operating revenues (exclusive of investment revenues) of all subsidiaries of SERVICE PROVIDER, including CUSTOMER.

2. "Proportionate Share of Head Counts" means the proportion that the budgeted number of full time employees of CUSTOMER bears to the total budgeted number of full time employees of all subsidiaries of SERVICE PROVIDER, including CUSTOMER.

3. "Costs" means the actual costs of providing a Service inclusive of all salaries, benefits and departmental costs.

ENERSOURCE HYDRO MISSISSAUGA INC.

("Service Provider")

and

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC.

("Customer")

SERVICES AGREEMENT

Effective as of

January 1, 2011

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made this 1st day of January, 2011 (the "Effective Date").

BETWEEN:

ENERSOURCE HYDRO MISSISSAUGA INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"SERVICE PROVIDER")**

and

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC., **a** corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"CUSTOMER")**

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. Each of SERVICE PROVIDER and CUSTOMER are subsidiaries of Enersource Corporation, as defined in the *Business Corporations Act* (Ontario);

3. SERVICE PROVIDER carries on the business of distributing electricity within the City of Mississauga and has agreed to provide certain services to CUSTOMER on the terms set forth in this Agreement;

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below:

(a) **"Agreement"**, **"hereto"**, **"hereof"**, **"herein"**, **"hereby"**, **"hereunder"** and similar expressions mean this Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the City of Mississauga;

(c) **"Claim"** has the meaning ascribed to such term in **Section 4.4**;

(d) **"Confidential Information"** means information CUSTOMER has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Default"** means in respect of Defaulting Party, an event set out in **Section 8.1;**

(f) **"Defaulting Party"** has the meaning ascribed to such term in **Section 8.1;**

(g) **"Effective Date"** means the date first written above;

(h) **"Event of Default"** means a Default, the notice and cure periods (if any) respecting which have expired;

(i) **"Force Majeure Event"** has the meaning ascribed to such term in **Section 9.1;**

(j) **"IESO"** means the Independent Electricity System Operator, or its successor;

(k) **"OEB"** means the Ontario Energy Board, or its successor;

(l) **"Law"** means any law, rule, regulation, code, order, writ, judgment, decree or other legal or regulatory determination by a court, regulatory agency, including the OEB and IESO, or governmental authority of competent jurisdiction;

(m) **"Party"** means a party to this Agreement and "Parties" means every party;

(n) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(o) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(p) **"Services"** has the meaning ascribed thereto in **Section 3.1** of this Agreement;

(q) **"Term"** has the meaning ascribed thereto in **Section 2.1** of this Agreement; and

(r) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by SERVICE PROVIDER on behalf of CUSTOMER in connection with providing the Services or incurred by CUSTOMER's Personnel while providing Services under this Agreement paid by SERVICE PROVIDER.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, Subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings;

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2
TERM

2.1 Term

This Agreement shall commence on the date set forth above and, subject to earlier termination as provided for in this Agreement, continue in effect for a term of one year, terminating on December 31, 2011 (the "Term"). The Term shall thereafter be automatically extended for successive additional one (1) year periods (each an "Extension Term") unless either party terminates this Agreement by no less than sixty (60) days written notice to the other.

ARTICLE 3
SERVICE PROVIDER SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, SERVICE PROVIDER shall provide, or cause to be provided, to CUSTOMER the services set out in **Schedule "A"** (collectively the "**Services**") at the rates set out in **Schedule "B"**, and such other services as CUSTOMER may request and SERVICE PROVIDER may agree to provide from time to time.

3.2 Performance Standards

(a) SERVICE PROVIDER shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) SERVICE PROVIDER shall make all reasonable efforts to meet or exceed performance measures established by the OEB.

(c) All SERVICE PROVIDER's Personnel with responsibility for carrying out SERVICE PROVIDER's responsibilities hereunder shall be familiar with CUSTOMER's local needs.

3.3 Changes

CUSTOMER and SERVICE PROVIDER may, from time to time, agree to modifications to a Service agreed to be provided hereunder by negotiating appropriate changes to the descriptions of the Service and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

3.4 General SERVICE PROVIDER Covenants

(a) SERVICE PROVIDER shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and SERVICE PROVIDER shall, when requested, provide CUSTOMER with adequate evidence of its compliance with this **Section 3.4;**

(b) SERVICE PROVIDER shall comply, while on the premises used by CUSTOMER, with all the rules and regulations of CUSTOMER from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) All SERVICE PROVIDER's Personnel with responsibility for the provision of Services shall be familiar with the CUSTOMER's service area.

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall negotiate in good faith to develop a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4
MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

No Personnel of the SERVICE PROVIDER shall have access to any Confidential Information in the possession of the CUSTOMER, except for purposes related to the Services and in compliance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the OEB.

4.2 Maintain Records

The CUSTOMER and SERVICE PROVIDER shall maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

CUSTOMER shall promptly give written notice to SERVICE PROVIDER of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of CUSTOMER, the number of employees of CUSTOMER, or any efforts relating to the organization of or collective bargaining by employees of CUSTOMER, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

CUSTOMER shall promptly give written notice to SERVICE PROVIDER, and SERVICE PROVIDER shall promptly give notice to CUSTOMER, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by CUSTOMER or SERVICE PROVIDER (whether or not any such Claim is covered by insurance) in respect of its own operations of which either of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5
FEES AND COSTS

5.1 Fees

CUSTOMER shall forthwith pay to SERVICE PROVIDER the fees and charges set out in **Schedule "B"** upon being advised such fees are due.

5.2 Taxes

In addition to the fees, CUSTOMER shall pay to SERVICE PROVIDER an amount equal to any and all Harmonized Sales Taxes, value-added taxes or any other taxes (excluding income taxes) properly exigible on the supply of Services provided by a third party under this Agreement.

5.3 Late Payment

If CUSTOMER fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at the rate of one and one half percent (1 ½ %) per month.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of SERVICE PROVIDER

SERVICE PROVIDER represents and warrants to CUSTOMER as follows and acknowledges that CUSTOMER is relying on such representations and warranties in connection herewith:

(a) SERVICE PROVIDER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario, licensed by the OEB and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of SERVICE PROVIDER, enforceable against SERVICE PROVIDER by CUSTOMER in accordance with its terms; and

(d) SERVICE PROVIDER has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of CUSTOMER

CUSTOMER represents and warrants to SERVICE PROVIDER as follows and acknowledges that SERVICE PROVIDER is relying on such representations and warranties in connection herewith:

(a) CUSTOMER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of CUSTOMER, enforceable against CUSTOMER by SERVICE PROVIDER in accordance with its terms.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification

(a) CUSTOMER shall indemnify, defend and hold harmless SERVICE PROVIDER, its' officers, directors, and employees (each a **"SERVICE PROVIDER Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"**), asserted against or suffered by any SERVICE PROVIDER Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(b) SERVICE PROVIDER shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the SERVICE PROVIDER Indemnities that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) CUSTOMER agrees that SERVICE PROVIDER's liability, if any, to CUSTOMER or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of SERVICE PROVIDER in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of SERVICE PROVIDER in the provision of the Services and shall not exceed an amount equal to the total amount paid by CUSTOMER to SERVICE PROVIDER under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) SERVICE PROVIDER shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that SERVICE PROVIDER shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on CUSTOMER, and CUSTOMER agrees to indemnify and hold harmless SERVICE PROVIDER from any such sanctions fines, penalties or similar obligations.

ARTICLE 8
DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party")** under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set forth:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9
GENERAL

9.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a **"Force Majeure Event").**

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

9.2 Dispute Resolution

If any dispute arising in relation to the application or interpretation of this Agreement (a **"dispute")** which cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by CUSTOMER, one appointed by SERVICE PROVIDER, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the dispute and to render a decision. The arbitrators shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the Parties.

9.3 Assignment

Neither Party shall, without the written approval of the other Party hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

9.4 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) if to SERVICE PROVIDER,

Enersource Hydro Mississauga Inc.
3240 Mavis Road
Mississauga, Ontario
L5C 3K1

Attn: Chief Operating Officer
Fax: (905) 566-2737

(b) if to CUSTOMER,

Enersource Hydro Mississauga Services Inc.
3240 Mavis Road
Mississauga, Ontario
LSC 3Kl

Attn: Director, EHMS Operations
Fax: (905) 566-2737

and shall be personally delivered or shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

9.5 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

9.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

9.7 Entire Agreement

This Agreement supersedes any prior agreement between the parties, and constitutes the entire Agreement between the Parties with respect to the Services and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

9.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

9.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9.10 Survival

The terms of **Article 4** and **Article 7** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

9.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

9.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

ENERSOURCE HYDRO MISSISSAUGA INC.

Per: _____
Name: Dan Pastoric
Title: Executive Vice-President & Chief Operating Officer
I have authority to bind the Corporation

Per: _____
Name: Raymond Rauber
Title: Vice-President, Engineering & Operations
I have authority to bind the Corporation

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC.

Per: _____
Name: Craig Fleming
Title: President
I have authority to bind the Corporation

Per: _____
Name: Norman Wolff
Title: Secretary
I have authority to bind the Corporation

Schedule "A"

Description of Services

1. **"Fleet Services"** includes the use of passenger vehicles and service vehicles that are owned by SERVICE PROVIDER.

2. **"Engineering, Construction and Operations Services"** includes design, construction or operational services performed by SERVICE PROVIDER's staff in response to a request by the CUSTOMER, such SERVICE PROVIDER's staff may include the following:

1.	**Inside Staff**	Senior Managers Project Managers Other Managers Supervisors Engineers Design Technicians Administrative Staff
2.	**Outside Staff**	Construction Supervisors Leadhands Journeyman Apprentice Lineman Inspection Equipment Operator Laborers Cable Locator Mechanics Forrester

3. **"Information Technology Services"** include comprehensive technology services such as data base development and support, network development and support, personal computer systems support and communication support.

4. **"Facilities Operations Services"** includes the operational services associated with the use of the head office building, any other real estate, furniture and computers, such services being directly or indirectly provided by SERVICE PROVIDER.

5. **"Safety Services"** include safety program development, training and health promotion, monitoring, reporting, implementation and support.

6. **"Usage Charge"** a monthly charge is allocated to compensate Service Provider for the use by Customer of assets owned by the Service Provider which are included in the utility rate base and not charged on an hourly basis ("Usage Assets").

7. "**Other Services**" includes services other than those specifically enumerated above and that are requested and provided from time to time under Section 3.1.

Schedule "B"
Fees for Services

	SERVICES	FEES
1.	**Fleet Services**	Fees shall be calculated and charged in accordance with the fleet rates in effect for SERVICE PROVIDER at any given time.
2.	**Engineering, Operations and Construction Services**	Fees shall be calculated and charged in accordance with the principles set out below in Note 1.
3.	**Information Technology Services**	Fees shall be calculated and charged on a Cost basis based on head count.
4.	**Facilities Operations Services**	Fees shall be calculated and charged on a Cost basis based on head count.
5.	**Safety Services**	Fees shall be calculated and charged on a Cost basis based on head count.
6.	**Usage Charge**	Charge shall be calculated and charged based on net book value of Usage Assets based on headcount.
7.	**Other Services**	Fees shall be calculated and charged on a Cost basis based on budgeted revenue or headcount.

NOTES:

1. Staff Rates – the following principles apply to the charging of rates for SERVICE PROVIDER's staff that perform Engineering, Operations and Construction Services for the CUSTOMER:

   Rates for Unionized employees: Rates for unionized employees of SERVICE PROVIDER will be charged at the rates set out in the current collective agreement applicable to SERVICE PROVIDER's (the "Collective Agreement"), plus an applicable benefit rate, which will be determined on an annual basis to reflect changes in benefits cost.

   Rates for Non-union employees: Rates for non-unionized employees will be charged at rates calculated based on average wages for employee groups including benefits which are determined on an annual basis to reflect changes in wages and benefits cost.

2. "**Cost**" means CUSTOMER's proportionate share of the actual amounts incurred by SERVICE PROVIDER in respect of the Services, being reflective of the CUSTOMER's proportionate use of Services.

3. Fees that are calculated and charged on a Cost basis are in accordance with actual costs incurred by SERVICE PROVIDER.

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC.

("Service Provider")

and

ENERSOURCE HYDRO MISSISSAUGA INC.

("Customer")

SERVICES AGREEMENT

Effective as of

January 1, 2011

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made this 1st day of January, 2011 (the "Effective Date").

BETWEEN:

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"SERVICE PROVIDER")**

and

ENERSOURCE HYDRO MISSISSAUGA INC.,
a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"CUSTOMER")**

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. Each of SERVICE PROVIDER and CUSTOMER are subsidiaries of Enersource Corporation, as defined in the *Business Corporations Act* (Ontario);

3. CUSTOMER carries on business of distributing electricity within the City of Mississauga;

4. SERVICE PROVIDER has agreed to provide certain services to CUSTOMER on the terms set forth in this Agreement;

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below:

(a) **"Agreement", "hereto", "hereof", "herein", "hereby", "hereunder"** and similar expressions mean this Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the City of Mississauga;

(c) **"Claim"** has the meaning ascribed to such term in **Section 4.4**;

(d) **"Confidential Information"** means information CUSTOMER has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Default"** means in respect of Defaulting Party, an event set out in **Section 8.1;**

(f) **"Defaulting Party"** has the meaning ascribed to such term in **Section 8.1;**

(g) **"Effective Date"** means the date first written above;

(h) **"Event of Default"** means a Default, the notice and cure periods (if any) respecting which have expired;

(i) **"Force Majeure Event"** has the meaning ascribed to such term in **Section 9.1;**

(j) **"IESO"** means the Independent Electricity System Operator, or its successor;

(k) **"OEB"** means the Ontario Energy Board, or its successor;

(l) **"Law"** means any law, rule, regulation, code, order, writ, judgment, decree or other legal or regulatory determination by a court, regulatory agency, including the OEB and IESO, or governmental authority of competent jurisdiction;

(m)**"Party"** means a party to this Agreement and "Parties" means every party;

(n) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(o) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(p) **"Services"** has the meaning ascribed thereto in **Section 3.1** of this Agreement;

(q) **"Term"** has the meaning ascribed thereto in **Section 2.1** of this Agreement; and

(r) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by SERVICE PROVIDER on behalf of CUSTOMER in connection with providing the Services or incurred by CUSTOMER's Personnel while providing Services under this Agreement paid by SERVICE PROVIDER.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, Subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings;

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2
TERM

2.1 Term

This Agreement shall commence on the date set forth above and, subject to earlier termination as provided for in this Agreement, continue in effect for a term of one year, terminating on December 31, 2011 (the "Term"). The Term shall thereafter be automatically extended for successive additional one (1) year periods (each an "Extension Term") unless either party terminates this Agreement by no less than sixty (60) days written notice to the other.

ARTICLE 3
SERVICE PROVIDER SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, SERVICE PROVIDER shall provide, or cause to be provided, to CUSTOMER the services set out in **Schedule "A"** (collectively the "**Services**") at the rates set out in **Schedule "B"**, and such other services as CUSTOMER may request and SERVICE PROVIDER may agree to provide from time to time.

3.2 Performance Standards

(a) SERVICE PROVIDER shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) SERVICE PROVIDER shall make all reasonable efforts to meet or exceed performance measures established by the OEB.

(c) All SERVICE PROVIDER's Personnel with responsibility for carrying out SERVICE PROVIDER's responsibilities hereunder shall be familiar with CUSTOMER's electricity service area and local needs. All customer, billing, accounting and other records kept in connection with this Agreement shall be readily available to CUSTOMER in an office within the CUSTOMER's service area.

3.3 Changes

CUSTOMER and SERVICE PROVIDER may, from time to time, agree to modifications to a Service agreed to be provided hereunder by negotiating appropriate changes to the descriptions of the Service and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

3.4 General SERVICE PROVIDER Covenants

(a) SERVICE PROVIDER shall be responsible for obtaining all necessary licenses and

permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and SERVICE PROVIDER shall, when requested, provide CUSTOMER with adequate evidence of its compliance with this **Section 3.4;**

(b) SERVICE PROVIDER shall comply, while on the premises used by CUSTOMER, with all the rules and regulations of CUSTOMER from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) All SERVICE PROVIDER's Personnel with responsibility for the provision of Services shall be familiar with the CUSTOMER's electricity service area.

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall negotiate in good faith to develop a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4
MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

No Personnel of the SERVICE PROVIDER shall have access to any Confidential Information in the possession of the CUSTOMER, except for purposes related to the Services and in compliance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the OEB

4.2 Maintain Records

The CUSTOMER and SERVICE PROVIDER shall maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

CUSTOMER shall promptly give written notice to SERVICE PROVIDER of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of CUSTOMER, the number of employees of CUSTOMER, or any efforts relating to the organization of or collective bargaining by employees of CUSTOMER, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

CUSTOMER shall promptly give written notice to SERVICE PROVIDER, and SERVICE PROVIDER shall promptly give notice to CUSTOMER, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by CUSTOMER or SERVICE PROVIDER (whether or not any such Claim is covered by insurance) in respect of its own operations of which either of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5
FEES AND COSTS

5.1 Fees

CUSTOMER shall forthwith pay to SERVICE PROVIDER the fees and charges set out in **Schedule "B"** upon being advised such fees are due.

5.2 Taxes

In addition to the fees, CUSTOMER shall pay to SERVICE PROVIDER an amount equal to any and all Harmonized Sales Taxes, value-added taxes or any other taxes (excluding income taxes) properly exigible on the supply of Services provided by a third party under this Agreement.

5.3 Late Payment

If CUSTOMER fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at the rate of one and one half percent (1 ½ %) per month.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of SERVICE PROVIDER

SERVICE PROVIDER represents and warrants to CUSTOMER as follows and acknowledges that CUSTOMER is relying on such representations and warranties in connection herewith:

(a) SERVICE PROVIDER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of SERVICE PROVIDER, enforceable against SERVICE PROVIDER by CUSTOMER in accordance with its terms; and

(d) SERVICE PROVIDER has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of CUSTOMER

CUSTOMER represents and warrants to SERVICE PROVIDER as follows and acknowledges that SERVICE PROVIDER is relying on such representations and warranties in connection herewith:

(a) CUSTOMER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario, licensed by the OEB and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of CUSTOMER, enforceable against CUSTOMER by SERVICE PROVIDER in accordance with its terms.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification

(a) CUSTOMER shall indemnify, defend and hold harmless SERVICE PROVIDER, its' officers, directors, and employees (each a **"SERVICE PROVIDER Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"**), asserted against or suffered by any SERVICE PROVIDER Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(b) SERVICE PROVIDER shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the SERVICE PROVIDER Indemnities that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) CUSTOMER agrees that SERVICE PROVIDER's liability, if any, to CUSTOMER or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of SERVICE PROVIDER in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of SERVICE PROVIDER in the provision of the Services and shall not exceed an amount equal to the total amount paid by CUSTOMER to SERVICE PROVIDER under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) SERVICE PROVIDER shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that SERVICE PROVIDER shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on CUSTOMER, and CUSTOMER agrees to indemnify and hold harmless SERVICE PROVIDER from any such sanctions fines, penalties or similar obligations.

ARTICLE 8
DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party")** under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set forth:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9
GENERAL

9.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a **"Force Majeure Event").**

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

9.2 Dispute Resolution

If any dispute arising in relation to the application or interpretation of this Agreement (a **"dispute")** which cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by CUSTOMER, one appointed by SERVICE PROVIDER, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the dispute and to render a decision. The arbitrators shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the Parties.

9.3 Assignment

Neither Party shall, without the written approval of the other Party hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

9.4 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) if to SERVICE PROVIDER,

Enersource Hydro Mississauga Services Inc.
3240 Mavis Road
Mississauga, Ontario
LSC 3Kl

Attn: Director, EHMS Operations
Fax: (905) 566-2737

(b) if to CUSTOMER,

Enersource Hydro Mississauga Inc.
3240 Mavis Road
Mississauga, Ontario
L5C 3K1

Attn: Chief Operating Officer
Fax: (905) 566-2737

and shall be personally delivered or shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

9.5 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

9.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

9.7 Entire Agreement

This Agreement supersedes any prior agreement between the parties, and constitutes the entire Agreement between the Parties with respect to the Services and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

9.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

9.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9.10 Survival

The terms of **Article 4** and **Article 7** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

9.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

9.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC.

Per:_____
Name: Craig Fleming
Title: President
I have authority to bind the Corporation

Per:_____
Name: Norman Wolff
Title: Secretary
I have authority to bind the Corporation

ENERSOURCE HYDRO MISSISSAGUA INC.

Per:_____
Name: Dan Pastoric
Title: Executive Vice-President & Chief Operating Officer
I have authority to bind the Corporation

Per:_____
Name: Raymond Rauber
Title: Vice-President, Engineering & Operations
I have authority to bind the Corporation

Schedule "A"

Description of Services

1. **"Fleet Services"** includes the use of service vehicles that are owned by SERVICE PROVIDER.

2. **"Engineering, Construction and Operations Services"** includes design, construction or operational services performed by SERVICE PROVIDER's staff in response to a request by the CUSTOMER, such SERVICE PROVIDER's staff may include the following:

1.	**Inside Staff**	Senior Managers Project Managers Other Managers Supervisors Engineers Design Technicians Administrative Staff
2.	**Outside Staff**	Construction Supervisors Leadhands Journeyman Streetlight Maintainers Inspection Equipment Operator Laborers Cable Locator

3. **"Information Technology Services"** include comprehensive technology services such as data base development and support, network development and support, personal computer systems support and communication support.

4. **"Facilities Operations Services"** includes the operational services associated with the use of the head office building, any other real estate, furniture and computers, such services being directly or indirectly provided by SERVICE PROVIDER.

5. **"Safety Services"** include safety program development, training and health promotion, monitoring, reporting, implementation and support.

6. "**Other Services**" includes services other than those specifically enumerated above and that are requested and provided from time to time under Section 3.1.

Schedule "B"
Fees for Services

	SERVICES	FEES
1.	**Fleet Services**	Fees shall be calculated and charged in accordance with the fleet rates in effect for SERVICE PROVIDER at any given time.
2.	**Engineering, Operations and Construction Services**	Fees shall be calculated and charged in accordance with the principles set out below in Note 1.
3.	**Other Services**	Fees shall be calculated and charged on a Cost basis.

NOTES:

1. Staff Rates – the following principles apply to the charging of rates for SERVICE PROVIDER's staff that perform Engineering, Operations and Construction Services for the CUSTOMER:

   Rates for Unionized employees: Rates for unionized employees of SERVICE PROVIDER will be charged at the rates set out in the current collective agreement applicable to SERVICE PROVIDER's (the "Collective Agreement"), plus an applicable benefit rate, which will be determined on an annual basis to reflect changes in benefits cost.

   Rates for Non-union employees: Rates for non-unionized employees will be charged at rates calculated based on average wages for employee groups including benefits which are determined on an annual basis to reflect changes in wages and benefits cost.

2. "**Cost**" means CUSTOMER's proportionate share of the actual amounts incurred by SERVICE PROVIDER in respect of the Services, being reflective of the CUSTOMER's proportionate use of Services.

3. Fees that are calculated and charged on a Cost basis are in accordance with actual costs incurred by SERVICE PROVIDER.

ENERSOURCE HYDRO MISSISSAUGA INC.

("Service Provider")

and

ENERSOURCE CORPORATION

("Customer")

SERVICES AGREEMENT

Effective as of

January 1, 2011

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made this 1st day of January, 2011 (the "Effective Date").

BETWEEN:

ENERSOURCE HYDRO MISSISSAUGA INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"SERVICE PROVIDER")**

and

ENERSOURCE CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"CUSTOMER")**

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. SERVICE PROVIDER carries on the business of distributing electricity within the City of Mississauga and has agreed to provide certain services to CUSTOMER on the terms set forth in this Agreement;

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below:

(a) **"Agreement", "hereto", "hereof", "herein", "hereby", "hereunder"** and similar expressions mean this Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the City of Mississauga;

(c) **"Claim"** has the meaning ascribed to such term in **Section 4.4**;

(d) **"Confidential Information"** means information CUSTOMER has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Default"** means in respect of Defaulting Party, an event set out in **Section 8.1;**

(f) **"Defaulting Party"** has the meaning ascribed to such term in **Section 8.1;**

(g) **"Effective Date"** means the date first written above;

(h) **"Event of Default"** means a Default, the notice and cure periods (if any) respecting which have expired;

(i) **"Force Majeure Event"** has the meaning ascribed to such term in **Section 9.1;**

(j) **"IESO"** means the Independent Electricity System Operator, or its successor;

(k) **"OEB"** means the Ontario Energy Board, or its successor;

(l) **"Law"** means any law, rule, regulation, code, order, writ, judgment, decree or other legal or regulatory determination by a court, regulatory agency, including the OEB and IESO, or governmental authority of competent jurisdiction;

(m) **"Party"** means a party to this Agreement and "Parties" means every party;

(n) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(o) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(p) **"Services"** has the meaning ascribed thereto in **Section 3.1** of this Agreement;

(q) **"Term"** has the meaning ascribed thereto in **Section 2.1** of this Agreement; and

(r) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by SERVICE PROVIDER on behalf of CUSTOMER in connection with providing the Services or incurred by CUSTOMER's Personnel while providing Services under this Agreement paid by SERVICE PROVIDER.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, Subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings;

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2
TERM

2.1 Term

This Agreement shall commence on the date set forth above and, subject to earlier termination as provided for in this Agreement, continue in effect for a term of one year, terminating on December 31, 2011 (the "Term"). The Term shall thereafter be automatically extended for successive additional one (1) year periods (each an "Extension Term") unless either party terminates this Agreement by no less than sixty (60) days written notice to the other.

ARTICLE 3
SERVICE PROVIDER SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, SERVICE PROVIDER shall provide, or cause to be provided, to CUSTOMER the services set out in **Schedule "A"** (collectively the "**Services**") at the rates set out in **Schedule "B"**, and such other services as CUSTOMER may request and SERVICE PROVIDER may agree to provide from time to time.

3.2 Performance Standards

(a) SERVICE PROVIDER shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) SERVICE PROVIDER shall make all reasonable efforts to meet or exceed performance measures established by the OEB.

(c) All SERVICE PROVIDER's Personnel with responsibility for carrying out SERVICE PROVIDER's responsibilities hereunder shall be familiar with CUSTOMER's local needs.

3.3 Changes

CUSTOMER and SERVICE PROVIDER may, from time to time, agree to modifications to a Service agreed to be provided hereunder by negotiating appropriate changes to the descriptions of the Service and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

3.4 General SERVICE PROVIDER Covenants

(a) SERVICE PROVIDER shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and SERVICE PROVIDER shall, when requested, provide CUSTOMER with adequate evidence of its compliance with this **Section 3.4;**

(b) SERVICE PROVIDER shall comply, while on the premises used by CUSTOMER, with all the rules and regulations of CUSTOMER from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) All SERVICE PROVIDER's Personnel with responsibility for the provision of Services shall be familiar with the CUSTOMER's service area.

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If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall negotiate in good faith to develop a substitute agreement with such amendments as are necessary to comply with such change of Law.

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The CUSTOMER and SERVICE PROVIDER shall maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

CUSTOMER shall promptly give written notice to SERVICE PROVIDER of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of CUSTOMER, the number of employees of CUSTOMER, or any efforts relating to the organization of or collective bargaining by employees of CUSTOMER, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

CUSTOMER shall promptly give written notice to SERVICE PROVIDER, and SERVICE PROVIDER shall promptly give notice to CUSTOMER, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by CUSTOMER or SERVICE PROVIDER (whether or not any such Claim is covered by insurance) in respect of its own operations of which either of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

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FEES AND COSTS

5.1 Fees

CUSTOMER shall forthwith pay to SERVICE PROVIDER the fees and charges set out in **Schedule "B"** upon being advised such fees are due.

5.2 Taxes

In addition to the fees, CUSTOMER shall pay to SERVICE PROVIDER an amount equal to any and all Harmonized Sales Taxes, value-added taxes or any other taxes (excluding income taxes) properly exigible on the supply of Services provided by a third party under this Agreement.

5.3 Late Payment

If CUSTOMER fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at the rate of one and one half percent (1 ½ %) per month.

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6.1 Representations and Warranties of SERVICE PROVIDER

SERVICE PROVIDER represents and warrants to CUSTOMER as follows and acknowledges that CUSTOMER is relying on such representations and warranties in connection herewith:

(a) SERVICE PROVIDER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario, licensed by the OEB, and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of SERVICE PROVIDER, enforceable against SERVICE PROVIDER by CUSTOMER in accordance with its terms; and

(d) SERVICE PROVIDER has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of CUSTOMER

CUSTOMER represents and warrants to SERVICE PROVIDER as follows and acknowledges that SERVICE PROVIDER is relying on such representations and warranties in connection herewith:

(a) CUSTOMER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of CUSTOMER, enforceable against CUSTOMER by SERVICE PROVIDER in accordance with its terms.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification

(a) CUSTOMER shall indemnify, defend and hold harmless SERVICE PROVIDER, its' officers, directors, and employees (each a **"SERVICE PROVIDER Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"**), asserted against or suffered by any SERVICE PROVIDER Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(b) SERVICE PROVIDER shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the SERVICE PROVIDER Indemnities that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) CUSTOMER agrees that SERVICE PROVIDER's liability, if any, to CUSTOMER or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of SERVICE PROVIDER in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of SERVICE PROVIDER in the provision of the Services and shall not exceed an amount equal to the total amount paid by CUSTOMER to SERVICE PROVIDER under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) SERVICE PROVIDER shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that SERVICE PROVIDER shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on CUSTOMER, and CUSTOMER agrees to indemnify and hold harmless SERVICE PROVIDER from any such sanctions fines, penalties or similar obligations.

ARTICLE 8
DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party")** under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set forth:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9
GENERAL

9.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a **"Force Majeure Event").**

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

9.2 Dispute Resolution

If any dispute arising in relation to the application or interpretation of this Agreement (a **"dispute")** which cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by CUSTOMER, one appointed by SERVICE PROVIDER, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the dispute and to render a decision. The arbitrators shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the Parties.

9.3 Assignment

Neither Party shall, without the written approval of the other Party hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

9.4 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) if to SERVICE PROVIDER,

Enersource Hydro Mississauga Inc.
3240 Mavis Road
Mississauga, Ontario
L5C 3K1

Attn: Chief Operating Officer
Fax: (905) 566-2737

(b) if to CUSTOMER,

Enersource Corporation
3240 Mavis Road
Mississauga, Ontario
LSC 3Kl

Attn: President & CEO
Fax: (905) 566-2737

and shall be personally delivered or shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

9.5 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

9.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

9.7 Entire Agreement

This Agreement supersedes any prior agreement between the parties, and constitutes the entire Agreement between the Parties with respect to the Services and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

9.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

9.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9.10 Survival

The terms of **Article 4** and **Article 7** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

9.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

9.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

ENERSOURCE HYDRO MISSISSAUGA INC.

Per: _____
Name: Dan Pastoric
Title: Executive Vice-President & Chief Operating Officer
I have authority to bind the Corporation

Per: _____
Name: Raymond Rauber
Title: Vice-President, Engineering & Operations
I have authority to bind the Corporation

ENERSOURCE CORPORATION

Per: _____
Name: Craig Fleming
Title: President and Chief Executive Officer
I have authority to bind the Corporation

Per: _____
Name: Norman Wolff
Title: Executive Vice President & Chief Financial Officer
I have authority to bind the Corporation

Schedule "A"

Description of Services

1. **"Fleet Services"** includes the use of passenger vehicles and service vehicles that are owned by SERVICE PROVIDER.

2. **"Engineering, Construction and Operations Services"** includes design, construction or operational services performed by SERVICE PROVIDER's staff in response to a request by the CUSTOMER, such SERVICE PROVIDER's staff may include the following:

1.	**Inside Staff**	Senior Managers Project Managers Other Managers Supervisors Engineers Design Technicians Administrative Staff
2.	**Outside Staff**	Construction Supervisors Leadhands Journeyman Apprentice Linemen Inspection Equipment Operator Laborers Cable Locator Mechanics Forrester

3. **"Information Technology Services"** include comprehensive technology services such as data base development and support, network development and support, personal computer systems support and communication support.

4. **"Facilities Operations Services"** includes the operational services associated with the use of the head office building, any other real estate, furniture and computers, such services being directly or indirectly provided by SERVICE PROVIDER.

5. **"Safety Services"** include safety program development, training and health promotion, monitoring, reporting, implementation and support.

6. **"Usage Charge"** – a monthly charge is allocated to compensate Service Provider for the use by Customer of assets owned by the Service Provider which are included in the utility rate base and not charged on an hourly basis ("Usage Assets").

7. "**Other Services**" includes services other than those specifically enumerated above and that are requested and provided from time to time under Section 3.1.

Schedule "B"
Fees for Services

	SERVICES	FEES
1.	**Fleet Services**	Fees shall be calculated and charged in accordance with the fleet rates in effect for SERVICE PROVIDER at any given time.
2.	**Engineering, Operations and Construction Services**	Fees shall be calculated and charged in accordance with the principles set out below in Note 1.
3.	**Information Technology Services**	Fees shall be calculated and charged on a Cost basis based on head count.
4.	**Facilities Operations Services**	Fees shall be calculated and charged on a Cost basis based on head count.
5.	**Safety Services**	Fees shall be calculated and charged on a Cost basis based on head count.
6.	**Usage Charges**	Charge shall be calculated and charged on net book value of Usage Assets based on headcount.
7.	**Other Services**	Fees shall be calculated and charged on a Cost basis based on budgeted revenue.

NOTES:

1. Staff Rates – the following principles apply to the charging of rates for SERVICE PROVIDER's staff that perform Engineering, Operations and Construction Services for the CUSTOMER:

   Rates for Unionized employees: Rates for unionized employees of SERVICE PROVIDER will be charged at the rates set out in the current collective agreement applicable to SERVICE PROVIDER's (the "Collective Agreement"), plus an applicable benefit rate, which will be determined on an annual basis to reflect changes in benefits cost.

   Rates for Non-union employees: Rates for non-unionized employees will be charged at rates calculated based on average wages for employee groups including benefits which are determined on an annual basis to reflect changes in wages and benefits cost.

2. "**Cost**" means CUSTOMER's proportionate share of the actual amounts incurred by SERVICE PROVIDER in respect of the Services, being reflective of the CUSTOMER's proportionate use of Services.

3. Fees that are calculated and charged on a Cost basis are in accordance with actual costs incurred by SERVICE PROVIDER.

ENERSOURCE CORPORATION

("Service Provider")

and

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC.

("Customer")

SERVICES AGREEMENT

Effective as of

January 1, 2011

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made this 1st day of January, 2011 (the "Effective Date").

BETWEEN:

ENERSOURCE CORPORATION, a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"SERVICE PROVIDER")**

and

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC., a corporation incorporated pursuant to the laws of the Province of Ontario

(hereinafter referred to as **"CUSTOMER")**

WHEREAS:

1. Each of the Parties to this Agreement are corporations incorporated under the *Business Corporations Act* (Ontario);

2. SERVICE PROVIDER has agreed to provide certain services to CUSTOMER on the terms set forth in this Agreement;

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement all capitalized terms herein shall have the meanings set forth below:

(a) **"Agreement", "hereto", "hereof", "herein", "hereby", "hereunder"** and similar expressions mean this Services Agreement together with all Schedules attached hereto, as they may be amended from time to time;

(b) **"Business Day"** means any day other than a Saturday, Sunday, statutory or bank holiday in the City of Mississauga;

(c) **"Claim"** has the meaning ascribed to such term in **Section 4.4**;

(d) **"Confidential Information"** means information CUSTOMER has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective distribution service;

(e) **"Default"** means in respect of Defaulting Party, an event set out in **Section 8.1;**

(f) **"Defaulting Party"** has the meaning ascribed to such term in **Section 8.1;**

(g) **"Effective Date"** means the date first written above;

(h) **"Event of Default"** means a Default, the notice and cure periods (if any) respecting which have expired;

(i) **"Force Majeure Event"** has the meaning ascribed to such term in **Section 9.1;**

(j) **"IESO"** means the Independent Electricity System Operator, or its successor;

(k) **"OEB"** means the Ontario Energy Board, or its successor;

(l) **"Law"** means any law, rule, regulation, code, order, writ, judgment, decree or other legal or regulatory determination by a court, regulatory agency, including the OEB and IESO, or governmental authority of competent jurisdiction;

(m) **"Party"** means a party to this Agreement and "Parties" means every party;

(n) **"Person"** means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(o) **"Personnel"** means employees, agents, professional advisors, contractors and subcontractors;

(p) **"Services"** has the meaning ascribed thereto in **Section 3.1** of this Agreement;

(q) **"Term"** has the meaning ascribed thereto in **Section 2.1** of this Agreement; and

(r) **"Third Party Expenses"** means all fees, costs and charges paid to third parties by SERVICE PROVIDER on behalf of CUSTOMER in connection with providing the Services or incurred by CUSTOMER's Personnel while providing Services under this Agreement paid by SERVICE PROVIDER.

1.2 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;

(b) all usage of the word "including" or the phrase "e.g.," in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded, and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, Subsections and Schedules and the insertion of headings is for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known or trade meanings are used herein in accordance with their recognized meanings;

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against any Party by reason of the extent to which any Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2
TERM

2.1 Term

This Agreement shall commence on the date set forth above and, subject to earlier termination as provided for in this Agreement, continue in effect for a term of one year, terminating on December 31, 2011 (the "Term"). The Term shall thereafter be automatically extended for successive additional one (1) year periods (each an "Extension Term") unless either party terminates this Agreement by no less than sixty (60) days written notice to the other.

ARTICLE 3
SERVICE PROVIDER SERVICES AND COVENANTS

3.1 Services

Subject to the terms, covenants and conditions contained in this Agreement, SERVICE PROVIDER shall provide, or cause to be provided, to CUSTOMER the services set out in **Schedule "A"** (collectively the "**Services**") at the rates set out in **Schedule "B"**, and such other services as CUSTOMER may request and SERVICE PROVIDER may agree to provide from time to time.

3.2 Performance Standards

(a) SERVICE PROVIDER shall perform the Services in a good and workmanlike manner and to a standard of performance that a competent professional and diligent independent provider of the services in the same circumstances would reasonably be expected to provide.

(b) SERVICE PROVIDER shall make all reasonable efforts to meet or exceed performance measures established by the OEB.

(c) All SERVICE PROVIDER's Personnel with responsibility for carrying out SERVICE PROVIDER's responsibilities hereunder shall be familiar with CUSTOMER's local needs.

3.3 Changes

CUSTOMER and SERVICE PROVIDER may, from time to time, agree to modifications to a Service agreed to be provided hereunder by negotiating appropriate changes to the descriptions of the Service and the consideration in connection with such changes and shall initial and attach amended schedules hereto.

3.4 General SERVICE PROVIDER Covenants

(a) SERVICE PROVIDER shall be responsible for obtaining all necessary licenses and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the Services and SERVICE PROVIDER shall, when requested, provide CUSTOMER with adequate evidence of its compliance with this **Section 3.4;**

(b) SERVICE PROVIDER shall comply, while on the premises used by CUSTOMER, with all the rules and regulations of CUSTOMER from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) All SERVICE PROVIDER's Personnel with responsibility for the provision of Services shall be familiar with the CUSTOMER's service area.

3.5 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable, then the Parties shall negotiate in good faith to develop a substitute agreement with such amendments as are necessary to comply with such change of Law.

ARTICLE 4
MUTUAL COVENANTS

4.1 Confidentiality of Confidential Information

No Personnel of the SERVICE PROVIDER shall have access to any Confidential Information in the possession of the CUSTOMER, except for purposes related to the Services and in compliance with the Affiliate Relationship Code for Electricity Distributors and Transmitters prescribed by the OEB.

4.2 Maintain Records

The CUSTOMER and SERVICE PROVIDER shall maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties acting reasonably.

4.3 Notification of Changes of Circumstances

CUSTOMER shall promptly give written notice to SERVICE PROVIDER of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of CUSTOMER, the number of employees of CUSTOMER, or any efforts relating to the organization of or collective bargaining by employees of CUSTOMER, or any lease or service arrangements contemplated with any third parties.

4.4 Notice of Claims, Etc.

CUSTOMER shall promptly give written notice to SERVICE PROVIDER, and SERVICE PROVIDER shall promptly give notice to CUSTOMER, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) or litigation (collectively, **"Claims"**) which it reasonably believes could have a material adverse effect on the fulfillment of any of the material terms hereof by CUSTOMER or SERVICE PROVIDER (whether or not any such Claim is covered by insurance) in respect of its own operations of which either of them is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5
FEES AND COSTS

5.1 Fees

CUSTOMER shall forthwith pay to SERVICE PROVIDER the fees and charges set out in **Schedule "B"** upon being advised such fees are due.

5.2 Taxes

In addition to the fees, CUSTOMER shall pay to SERVICE PROVIDER an amount equal to any and all Harmonized Sales Taxes, value-added taxes or any other taxes (excluding income taxes) properly exigible on the supply of Services provided by a third party under this Agreement.

5.3 Late Payment

If CUSTOMER fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at the rate of one and one half percent (1 ½ %) per month.

ARTICLE 6
REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of SERVICE PROVIDER

SERVICE PROVIDER represents and warrants to CUSTOMER as follows and acknowledges that CUSTOMER is relying on such representations and warranties in connection herewith:

(a) SERVICE PROVIDER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario, and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate action;

(c) this Agreement constitutes a legal, valid and binding obligation of SERVICE PROVIDER, enforceable against SERVICE PROVIDER by CUSTOMER in accordance with its terms; and

(d) SERVICE PROVIDER has the necessary resources and expertise to acquire or perform the Services.

6.2 Representations and Warranties of CUSTOMER

CUSTOMER represents and warrants to SERVICE PROVIDER as follows and acknowledges that SERVICE PROVIDER is relying on such representations and warranties in connection herewith:

(a) CUSTOMER is a corporation, duly incorporated, validly existing and in good standing under the laws of the Province of Ontario and it has the rights, powers and privileges to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement has been duly authorized by all necessary corporate actions; and

(c) this Agreement constitutes a legal, valid and binding obligation of CUSTOMER, enforceable against CUSTOMER by SERVICE PROVIDER in accordance with its terms.

ARTICLE 7
INDEMNIFICATION

7.1 Indemnification

(a) CUSTOMER shall indemnify, defend and hold harmless SERVICE PROVIDER, its' officers, directors, and employees (each a **"SERVICE PROVIDER Indemnitee")** from and against any and all claims, demands, suits, losses, liabilities, damages, obligations, payments, costs and expenses and accrued interest thereon (including the costs and expenses of, and accrued interest in respect of, any and all actions, suits, proceedings, assessments, judgments, awards, settlements and compromises relating thereto and reasonable lawyers' fees and reasonable disbursements in connection therewith) (each an **"Indemnifiable Loss"**), asserted against or suffered by any SERVICE PROVIDER Indemnitee relating to, or in connection with, or resulting from or arising out of the provision of the Services under this Agreement.

(b) SERVICE PROVIDER shall be deemed to hold the provisions of **Section 7.1(a)** that are for the benefit of the SERVICE PROVIDER Indemnities that are not party to this Agreement in trust for such persons as third party beneficiaries under this Agreement.

7.2 Limit of Liability

(a) CUSTOMER agrees that SERVICE PROVIDER's liability, if any, to CUSTOMER or any third party in connection with or arising under this Agreement, including without limitation, any liability arising from any act or omission of SERVICE PROVIDER in the provision of the Services, whether arising in contract, tort, equity or otherwise, shall be limited to actions or liabilities resulting solely from the fraud or willful misconduct of SERVICE PROVIDER in the provision of the Services and shall not exceed an amount equal to the total amount paid by CUSTOMER to SERVICE PROVIDER under this Agreement for Services over the twelve month period preceding the date that the cause of action or claim giving rise to the liability first arose.

(b) SERVICE PROVIDER shall not be liable for any damages caused by delay in delivering or furnishing any Services referred to in this Agreement.

7.3 Notwithstanding anything else to the contrary in this Agreement, the Parties agree that SERVICE PROVIDER shall not be responsible for any sanctions, fines, penalties, or similar obligations imposed on CUSTOMER, and CUSTOMER agrees to indemnify and hold harmless SERVICE PROVIDER from any such sanctions fines, penalties or similar obligations.

ARTICLE 8
DEFAULT

8.1 Events of Default

The occurrence of any one or more of the following events shall constitute a Default by a Party (the **"Defaulting Party")** under this Agreement and shall constitute an Event of Default if such Default is not remedied prior to the expiry of the relevant notice period (if any) and the relevant cure period (if any) applicable to such Default as hereinafter set forth:

(a) if the Defaulting Party defaults in the payment of any amount due to the other Party under this Agreement and such default shall continue unremedied for sixty (60) days following notice in writing thereof to the Defaulting Party by the other Party; and

(b) if the Defaulting Party fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of sixty (60) days following notice in writing thereof (giving particulars of the failure in reasonable detail) from the other Party to the Defaulting Party or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that the Defaulting Party:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) its proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to the other Party acting reasonably.

ARTICLE 9
GENERAL

9.1 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement:

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party, (each a **"Force Majeure Event").**

Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(a) such Force Majeure Event continues; and

(b) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Parties by telephone (to be confirmed in writing within five (5) days of the inception of such delay) of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

9.2 Dispute Resolution

If any dispute arising in relation to the application or interpretation of this Agreement (a **"dispute")** which cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the dispute shall be referred to a panel of three arbitrators, one of which shall be appointed by CUSTOMER, one appointed by SERVICE PROVIDER, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the dispute and to render a decision. The arbitrators shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to the Parties no later than thirty (30) days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on the Parties.

9.3 Assignment

Neither Party shall, without the written approval of the other Party hereto, which may be arbitrarily withheld in the sole discretion of either of them, assign or transfer its interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment in contravention of this Agreement shall be void.

9.4 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and addressed as follows:

(a) if to SERVICE PROVIDER,

Enersource Corporation
3240 Mavis Road
Mississauga, Ontario
LSC 3Kl

Attn: President & CEO
Fax: (905) 566-2737

(b) if to CUSTOMER,

Enersource Hydro Mississauga Services Inc.
3240 Mavis Road
Mississauga, Ontario
L5C 3K1

Attn: Director, EHMS Operations
Fax: (905) 566-2737

and shall be personally delivered or shall be sent by fax and the Party sending such notice shall telephone to confirm receipt. A copy of any such notice shall also be sent on the date such notice is transmitted by fax by registered express mail or courier with the capacity to verify receipt of delivery. Any Party may change its address or fax number for notification purposes by giving the other Party notice of the new address or fax number and the date upon which it will become effective in accordance with the terms of this Agreement. A notice shall be deemed to have been received as of the next Business Day following its transmission by fax.

9.5 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent granted by law. If any clause is deemed unenforceable or contrary to law, the parties shall alter the said clause and this agreement to produce enforceability or compliance with law such that the intent of the original clause is maintained and such change or alteration may be established through the dispute resolution clause in this agreement.

9.6 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of any other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

9.7 Entire Agreement

This Agreement supersedes any prior agreement between the parties, and constitutes the entire Agreement between the Parties with respect to the Services and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

9.8 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

9.9 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

9.10 Survival

The terms of **Article 4** and **Article 7** shall survive the expiration of this Agreement or termination of this Agreement for any reason.

9.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties.

9.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF this Agreement has been executed by the duly authorized signatories of the parties hereto as of the date first written above.

ENERSOURCE CORPORATION

Per:_____
Name: Craig Fleming
Title: President and Chief Executive Officer
I have authority to bind the Corporation

Per:_____
Name: Norman Wolff
Title: Executive Vice President &
Chief Financial Officer
I have authority to bind the Corporation

ENERSOURCE HYDRO MISSISSAUGA SERVICES INC.

Per:_____
Name: Craig Fleming
Title: President
I have authority to bind the Corporation

Per:_____
Name: Norman Wolff
Title: Secretary
I have authority to bind the Corporation

SCHEDULE "A"

Description of Services

1. **"Finance Services"** include treasury, controllership, rate setting and audit.

(a) Treasury services include financing, i.e.: issuance and management of debt, operating line of credit, cash flow management and investment of funds, banking, financial guarantees, i.e.: letters of credit, bonds, prudentials, payroll services, accounts payable services, office services, obtaining and maintaining credit ratings, trustee reporting, management of customer deposits, interest and T5 reporting, taxation (PILS), HST or tax remittances and corporate VISA card.

(b) Controllership services include financial systems, financial processes, policies and procedures, financial controls and compliance, financial reporting and analysis, annual budgets, financial operations, billing, collecting, capitalization and depreciation, WIP and inventory, labour charging, allocations and burdens, managing external audit, liability, fleet, facilities, OEB reporting, incentive plan reporting, billing system quality control.

(c) Rate setting services include providing analytical services and recommendations in regards to rate development and the regulatory filings, submissions and attendance at hearings as necessary.

2. **"Human Resources Services"** include resource development and workforce sustainment including recruitment, compensation and benefits, employee relations, labour relations, training and development, policy development, and performance management and organization development.

3. **"Procurement Services"** include the preparation of tender documents and organization of the tendering process, obtaining quotes for purchases and sourcing suppliers, processing of internal requisitions, preparation of purchase orders, stocking of inventory for planned and unplanned service orders and determining inventory levels.

4. **"Corporate Relation Services"** include the preparation and delivery of broad-based and strategic communications to the general public and specific target audiences, including written publications such as media releases and annual reports and community relations activities and events.

5. **"Executive Management Services"** includes the provision of executive management and advice in the running of CUSTOMER.

6. "**Corporate Governance Services**" include the provision of strategic direction and leadership, and the governance of the company's activities, which include supporting its board of directors, board committees and executive management, and legal services.

7. **"Internal Audit and Enterprise Risk Services"** include assessing and reporting of all entity risks, including environmental and business continuity risks and providing independent and objective assurance designed to strengthen the organization's internal control structure and safeguard the company's assets.

8. **"Legal Services"** include directing the legal affairs including commercial, corporate, contractual, legislative and regulatory litigation and legal advice.

9. "**Other Services**" include services other than those specifically enumerated above and that are requested and provided from time to time under Section 3.1.

SCHEDULE "B"
Fees for Services

	SERVICES	FEES
1.	**Finance Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
2.	**Human Resources Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Head Count.
3.	**Procurement Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
4.	**Corporate Relations Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
5.	**Corporate Governance Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
6.	**Internal Audit and Enterprise Risk Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
7.	**Legal Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.
8.	**Other Services**	Fees shall be calculated and charged on a Cost basis based on CUSTOMER's Proportionate Share of Operating Revenues.

NOTES:

1. "Proportionate Share of Operating Revenues" means the proportion that the budgeted operating revenues (exclusive of investment revenues) of CUSTOMER bears to the total budgeted operating revenues (exclusive of investment revenues) of all subsidiaries of SERVICE PROVIDER, including CUSTOMER.

2. "Proportionate Share of Head Counts" means the proportion that the budgeted number of full time employees of CUSTOMER bears to the total budgeted number of full time employees of all subsidiaries of SERVICE PROVIDER, including CUSTOMER.

3. "Costs" means the actual costs of providing a Service inclusive of all salaries, benefits and departmental costs.

enersource	CORPORATE POLICY		
SUBJECT	**CODE OF CONDUCT**	NUMBER	**100-1**
DEPARTMENT	**CORPORATE**	REVISED DATE	**October 2009**
REPLACES POL#	**N/A**	ORIGINAL DATE	**May 2008**

ENERSOURCE CORPORATION | 2009 CODE OF CONDUCT

OUR VISION

OUR CORPORATE VISION IS TO BE THE LEADING ENERGY SERVICES COMPANY, DRIVEN BY AN EXCEPTIONAL WILLINGNESS TO EXCEED OUR CUSTOMERS' AND STAKEHOLDERS' EXPECTATIONS THROUGH INTEGRITY, INNOVATION, TEAMWORK AND EXCELLENCE IN EVERYTHING WE DO.

1.1 GENERAL

This Code applies to the Board of Directors and employees of Enersource.

Enersource refers to Enersource Corporation and any majority owned subsidiaries.

The Code of Conduct is one of the principle drivers of the Corporation. Our corporate vision states that integrity is required in everything we do.

The Code of Conduct summarizes the level of ethics and business conduct required of all employees to enable us to achieve this level of integrity. The Code is only a summary and is not expected to cover every eventuality. It does not preclude the use of common sense and good judgment. Employees are expected to operate with integrity in everything they do. Should an employee be confronted with a situation where guidance is required, the employee should first refer to this Code. If the answer is not clear from the Code, or if further advice is needed, the matter should be discussed with your immediate supervisor, Human Resources Division or a member of senior management. If you are unable to follow this process due to the nature of the problem, or in good faith, believe the advice received is unethical, other contacts are available as described in Section 3, Administration, of this Code.

The Code requires employees to report actual and suspected violations. All information will be kept confidential at the request of the person providing the information. It is the Corporation's policy not to take any action against an employee who reports an alleged violation in good faith. This applies whether or not the report proves to be accurate.

The Corporation relies on its ethical values and takes seriously any violations of these values. Failure to comply with the Code will result in disciplinary action up to and including termination and legal action as appropriate.

2.1 LAWS, STATUTES AND REGULATIONS

All employees must comply with the various acts, statutes and regulations governing activities in the jurisdictions in which we carry on business. This includes complying both within the letter of the law and the intent of the law.

2.2 CORPORATE POLICIES AND PROCEDURES

All employees must comply with the corporate policies and procedures. Except for those policies designated "Confidential", policies are published on the corporate intranet. Procedures can include both written and verbal instructions.

2.3 RESPECT AND DIGNITY

All employees have the right to work in an environment of mutual respect, free from harassment. Our customers, suppliers, contractors and all external parties have a right to this same level of respect. We must be mature, courteous, supportive and co-operative at all times in our dealings with others. We must refrain from any form of harassment, whether intentional or unintentional, because of race, ancestry, place of origin, colour, ethnic origin, citizenship, creed, sex, sexual orientation, age, marital status, same-sex partnership status, family status, or disability.

2.4 PRIVACY AND CONFIDENTIALITY

Employees, and everyone they deal with, have a right to confidential information being kept private. Confidential information refers to all oral and written information including: discussions, customer data, contracts, letters of intent, financial statements, cost and expense data, environmental data, production data, technology and any other information that is not generally available from public or published information. During the course of business we will have access to confidential personal and business information. We must ensure that this information is provided to only those people

who need to know it for legal or business purposes and that the information is not made available to others. This includes such physical measures as locking filing cabinets, securing computer databases and shredding documents when they are no longer necessary. We also have a responsibility to ensure that competitive and customer information held by the regulated portion of our business is not shared with the non-regulated portion unless it is shared in accordance with the requirements of the Affiliates Relationships Code of the Ontario Energy Board.

2.5 CONFLICT OF INTEREST

All employees must always operate free from conflicting interests.

Conflict of Interest may exist in circumstances where we are required to exercise judgment, make a decision, or give advice but we are, or could be, in a position to gain or lose, directly or indirectly, from the decision or action. We must not be in a position where we will be influenced, or might be perceived as being influenced, by our personal or conflicting interests. This would include any potential situation where a relative or associate could be hired by the Corporation or could be assigned by a supplier to work involving the Corporation. It could also occur in cases where another business that we might be involved in could benefit from transactions involving the Corporation. Where there is a conflict, a potential conflict, or the possibility of a perceived conflict, we must immediately inform our supervisor and wherever possible remove ourselves from the situation. The Corporation will ultimately make the decision on the appropriate manner in which to proceed.

2.6 USE OF CORPORATE ASSETS

The Corporation makes a substantial investment in assets to assist us to more effectively carry out our duties. These assets, whether tangible, intangible, or electronic, include the Corporation's products, reputation, equipment, vehicles, computers and software. We must use these assets for the betterment of the Corporation and protect them against loss, theft, abuse and unauthorized use or disposal.

2.6.1 USE OF CORPORATE ELECTRONIC ASSETS

Enersource's information and computing assets are essential to the company's business success, and must be protected from loss, damage or misuse. We must all adhere to the Corporations' Information security Policy (ISP) which serves as Enersource's constitution to govern how employees use the Corporation's Information Technology resources. Adherence to the 'ISP' will enable Enersource to ensure the confidentiality, integrity and availability of information, reduce business and legal risk, and protect the reputation of the company. We must all be aware of the 'ISP' and our respective obligations as set forth therein as well as Enersource's Electronic Mail and Internet Use, and Privacy of Information Policies.

Enersource's information and computer assets are vulnerable to threats. A single unauthorized exception to security measures can jeopardize other users, customers and even outside organizations such as business partners. Non-compliance with the 'ISP' may put the confidentiality, integrity and availability of Enersource's information and computer assets at risk. Notwithstanding these policies, we must all ensure as a minimum:

We will not download unauthorised software;

We will maintain physical asset and systems security;

We maintain logical security by strictly observing password rules and not sharing our passwords;

We will not loan any equipment to others;

We will not use assets for excessive personal or non Enersource use;

Pornography or other offensive material must never be viewed, downloaded or stored on Enersource property

2.7 MAKING AND KEEPING COMMITMENTS ON BEHALF OF THE CORPORATION

The Corporation derives its business and undertakes its operations through commitments made by employees with customers, suppliers, and other stakeholders. Our employees are empowered to take action to meet customer needs. However, we must take extreme care in whatever we commit on behalf of the Corporation. We must only commit to what we believe is reasonable and achievable and we must only make commitments within our authority. For example, while we might be in a position to deal with customers and suppliers we might not have the authority to commit the Corporation. In these dealings we must ensure the other party is not misled into thinking a contract has been agreed to. Only designated senior executives (Signing Officers) are authorized to sign contracts on behalf of the Corporation and these must go through a review process.

2.8 INTEGRITY OF CORPORATE INFORMATION AND RECORDS

The Corporation takes seriously the accuracy of its information and records including both verbal and written statements. There is a very high level of risk relating to any inaccurate statements or records. These could be: inaccurate verbal statements to the public affecting their confidence in the Corporation; inaccurate customer records resulting in billing errors; inaccurate records of facilities or electrical equipment resulting in health, safety and environmental exposure to employees and the public; and, inaccurate financial information, resulting in inappropriate investment decisions. We have a responsibility to ensure that all information is accurately and honestly stated and recorded.

2.9 THEFT AND FRAUD

No form of theft or fraud can be tolerated in an ethical company. It is a grave breach of responsibility and trust when theft of employee, corporate or public property or fraud occurs. Theft occurs when a person fraudulently and/or without right takes or converts to their use or the use of another person, anything with intent to deprive the owner of it.

Fraud occurs when a person by falsehood or other deceitful means, defrauds the public or any person of any property, money or valuable security or property. Any employee found to have committed or have planned to commit fraud or theft will be subject to immediate dismissal for cause and potential legal action. Employees under investigation may also be suspended, with or without pay, pending completion of an investigation, depending on the circumstances of the case and the best interest of the Corporation.

2.10 IMPROPER PAYMENTS

The Corporation recognizes that building relationships with customers, suppliers and other stakeholders is an integral part of doing business. Therefore, offering and accepting reasonable hospitality and token gifts may be appropriate in certain circumstances. However, the Corporation's reputation for fair dealings with others should not be put at risk through making or receiving any improper payments such as bribes or kickbacks.

This includes giving or receiving any form of benefit to induce favourable personal or business treatment or to improperly affect business or government decisions. We must evaluate carefully any decisions about giving or receiving gifts. Any gifts should only have nominal value. We must demonstrate accountability by refusing to give or receive gifts of a magnitude that could appear to influence personal or business decisions.

2.11 HEALTH, SAFETY AND THE ENVIRONMENT

Delivery of the Corporation's products safely and without harm to the environment is essential to the success of the business. The Corporation is committed to maintaining the environment and the health and safety of its employees and the public. We all have accountability for health, safety and the environment. Fulfilling our individual accountabilities is a vital and fundamental requirement of

every employee. All employees have a personal responsibility to come to work fit for duty and to work safely.

Where appropriate, employees should immediately correct any workplace or environmental hazards. Furthermore, employees are required to report all injuries, incidents or hazards to their supervisor immediately during and/or following an occurrence.

2.12 SUPPORTING THE COMMUNITY

The Corporation strongly believes in supporting the local community. It does this through supporting local events and taking part in civic activities. It also encourages employees to take part in, and support, such events. The Corporation has chosen to officially support a limited number of local charities as it feels that this is the most effective use of its resources. It recognizes that employees will make their own choices in these matters. However, the Corporation must limit the business time and facilities used by individual employees in supporting their chosen charities. Business time and facilities, including use of corporate-wide emails cannot be used for charities not supported by the Corporation.

2.13 EMPLOYMENT RESPONSIBILITIES

Employees at all levels have a responsibility to provide their best effort in undertaking their work for the Corporation. We must work the time for which we are being paid and give full attention exclusively to performance of our duties. As part of our employment relationship we agree not to engage in, nor become connected in any capacity with, any other employment or business occupation, or become a director, officer or agent of any other company, firm or individual for the purpose of earning income, without the prior written consent of the Corporation. We must maintain our skills and qualifications for our work and present an appropriate image to our customers,

community and one another. This includes, for example, maintaining a driver's license in good standing if required to drive a corporate vehicle and wearing the appropriate business attire.

Independent members of the Board of Directors may hold other positions as long as the positions do not impair their ability as a member of the Enersource Board nor conflict with the Board's business. Directors must comply with the requirements of the Board, Director, and Committee Mandates.

3.1 ETHICS COMMITTEE

The CEO of the Corporation is accountable to the Board of Directors, through the Human Resource and Corporate Governance Committee, for the ethical culture of the Corporation. The administrative aspects of this Code are undertaken by an Ethics Committee consisting of at least three executives of the Corporation. The Committee is responsible for:

- Maintaining and updating the Code of Conduct;
- Giving advice and training on the Code;
- Individual, or as a group, being available to any person who wants to discuss any aspects of the Code;
- Ensuring the confidentiality of information provided where the person providing the information requests that this data should be kept confidential;
- Ensuring the anonymity of the person who provides information on violations of the Code if the person requires to remain anonymous;
- Reporting to the Board of Directors on violations of the Code;

3.2 REPORTING OF VIOLATIONS

If you observe any violations of the Code or wish to discuss a situation that may be unethical the matter should first be reviewed if possible, with your immediate supervisor, manager, human resources representatives or a member of senior management. If you are unable to follow this process due to the nature of the problem, or in good faith, believe the advice received is unethical two additional resources are available:

1. You may confidentially contact any of the members of the Ethics Committee as follows: Executive Vice President, Chief Operating Officer at extension #4100, Vice President, Human Resources at extension #4070 or Director, Internal Audit & Enterprise Risk at extension #4232.

2. You may anonymously contact the Enersource Confidential Code of Conduct Reporting Line by calling 1(877) 318-9180 or via the web at EthicsPoint.com.

These contacts are strictly obliged to maintain employee confidentiality.

3.3 VERIFICATION OF THE CODE

All new employees will signify their acceptance of the Code at the start of their employment. Employees will, as part of their annual performance review process acknowledge their continued commitment to the Enersource Corporation Code of Conduct. All Employees will also, complete a refresher annually.

| 09.09

enersource
Corporation

Enersource Corporation
3240 Mavis Road, Mississauga, Ontario, L5C 3K1
www.enersource.com

Signing Page, Code of Conduct #100-1

APPROVAL LEVELS
NEW POLICIES AND REVISIONS

√	Title	Name	Division/Dept.	Signature	Date Approved
	Director, Internal Audit & Enterprise Risk	Michael Murphy	Corporate	Michael Murphy	March 26, 2010
	Executive Vice President and COO	Dan J. Pastoric	Enersource Hydro Mississauga Inc.		26 March '10
	President & CEO	Craig Fleming	Corporate		M/d 26/10

All policies will be reviewed annually and revised by originating department.

	Annual Review Date	Initials
President & C.E.O.		

APPROVED 2009 APPROVED 2010

Purchasing Strategy

Enersource Corporation's ("EC") Purchasing department is responsible for the acquisition of goods and services for all of the EC-affiliated companies, including Enersource Hydro Mississauga Inc. ("Enersource"). The Purchasing department is also responsible to provide inventory control services along with the procurement of these parts for all of the direct material used. The Purchasing department is involved in all aspects of the procurement process, including issuing the approved purchase orders pursuant to Purchasing Policy # 500-002, found at Exhibit 4 Tab 5 Schedule 1 Appendix 1. The Purchasing Policy stipulates that all acquisitions shall be covered by purchase orders, with noted exceptions as defined in the policy. Purchases between $7,500 and $99,999 must have a minimum of three written quotes and purchases over $100,000 must be formally tendered. In cases where single-source procurement is necessary, the approval to proceed is authorized by the divisional VP and approved by both the COO and the CFO. In cases where the purchasing policy wasn't followed, the incident is reported to the Enersource Board of Directors' Audit Committee through a formal reporting system.

Vendors

Purchases are processed through the corporate enterprise resource planning ("ERP") system (Oracle's JD Edwards application system, or "JDE") and all requisitions are checked electronically for budget compliance during this process.

The Enersource Signing Authority Policy # 500-005, found at Exhibit 4 Tab 5 Schedule 1 Appendix 2, describes the signing authorization guidelines for the purchase of all goods and services.

In 2011, $103,000 worth of invoices was processed through the corporate ERP for all goods and services for all EC companies. A total of $10,600 (an average of $880 per month) in direct material was received and a total of $11,000 (an average of $910 per month) was issued. Overall, an inventory of between $7,000 and $7,700 was maintained over the year, ending at $7,300 as of December 31, 2011.

The procurement practices of Enersource ensure the optimal inventory turnover ratio while balancing the necessary inventory service level for the operations requirements. Enersource currently has a yearly turnover ratio of 1.5. Enersource does not separate its inventory for maintenance purposes; the total dollar amounts represent all inventories to support both the new construction and maintenance requirements for the electrical system.

Inventory requirements are reviewed by the Purchasing department staff and purchased to accommodate both active construction jobs and to cover safety stock for the maintenance component. There are over 2,500 different inventory part numbers ("SKU's") used in the construction process in order to support the electrical grid within the Enersource service area.

Enersource utilizes a competitive process to procure inventory for the operations function. Transformers, which are the highest priced commodity of the inventory families, are tendered to pre-approved manufacturers, and contracts are put in place for periods of between three to five years. The pricing model for these procurements is considered a "shared-risk model" which provides mechanisms to increase or decrease the pricing for these parts according to the price of that commodity during a predetermined timeframe.

Purchases for cable and wire are also tendered and are priced firm except for metals. This pricing is also a form of a "shared-risk model" and the pricing for the

cable is updated according to the price of metal. Each cable or wire has a set percentage of copper or aluminum content and the pricing for these metals fluctuates weekly. Pricing for this cable is set based on the metal pricing for the week that it ships to Enersource from the vendor. The contract period for this commodity is typically three to five years. The majority of all other inventory items are tendered once every two years and prices are firm for the two-year period.

enersource		CORPORATE POLICY	
SUBJECT	PURCHASING	NUMBER	500-2
DEPARTMENT	Finance	REVISED DATE	March 2012
REPLACES POL#	Policy No. 771	ORIGINAL DATE	June 2005

POLICY

The company will acquire materials and services that meet or exceed the specified requirements at the lowest long term owning cost.

This will be achieved through the company meeting the following requirements:

- The Purchasing Department will provide prompt, efficient procurement of quality materials and services and, where required, only pre-qualified suppliers with acceptable or better performance are to be used.
- The Purchasing Department is to be used by all business units and affiliated companies for all significant purchases.
- The Purchasing Department must be involved in all purchasing arrangements including contracts and leases.
- Strategic purchasing alliances with suppliers and other purchasing organizations are to be pursued.
- Purchases are only to be made within approved budget levels and signing authority limits unless prior approval is obtained in accordance with Enersource's Signing Authority Policy (#500-5).
- At least three competitive quotes are to be obtained for purchases above $7,500 and a formal tendering process is to be followed for purchases over $100,000. The only exceptions are where there are limited sources of supply, where a strategic alliance is in place for products and services listed in section 3.1 of this policy or in a Single Source situation (see corporate policy Single Source Vendor Relationship #800-3).
- Streamlining of purchases of low value items is to be achieved through the use of credit card purchases where credit cards are acceptable.
- All exceptions to and violations of the purchasing policy and procedures will be scrutinized by the Executive Vice President and Chief Financial Officer who will take any necessary action and will report exceptions and violations to the Audit Committee.

- Purchasing Department staff is to maintain the highest level of integrity and apply superior business standards, including full adherence to the corporate Code of Conduct and the Code of Ethics of the Purchasing Management Association of Canada.

PROCEDURE

1.0 PURCHASES OF GOODS AND SERVICES UNDER $7,500

1.1 Who can make Purchases

Purchases of goods and services costing less than $7,500 in total, excluding taxes, should be made within Business Units in accordance with approved signing authority levels. (See Signing Authority Policy (# 500-5)). Whenever possible the Corporate Credit Card should be used for these purchases. Any purchases that are part of a long-term commitment or involve a lease must be made based on the total value of the purchase.

1.2 Purchasing Standards to be Used by All Employees

In all dealings with current and potential suppliers employees must:

- Deliver maximum value to the Corporation and its affiliates in all transactions without prejudice.
- Consider only the interest of the Corporation and its affiliates in all transactions.
- Conduct themselves in a professional manner in all dealings with suppliers to uphold the reputation of the Corporation and its affiliates.
- Operate in a manner that will not result in preferential treatment of any supplier.
- Ensure confidential and/or proprietary information is secured from exposure to unauthorized parties.
- Ensure no advantage is taken of supplier's errors.
- Demonstrate consideration of, and co-operation with suppliers.
- Ensure no undue or unnecessary expense is imposed on the Company or any supplier.
- Exercise honesty and integrity in all purchasing transactions. Employees will denounce all forms of bribery, keeping themselves free from any unjustified obligations to suppliers.

- Ensure no gifts, gratuities or benefits, other than token, are received from any vendors or their agents. All gifts, regardless of value, must be reported to the employee's Supervisor.
- Report immediately all unethical practices on the part of employees or vendors.
- Ensure all vendors are given fair and equal treatment.
- Give prompt and courteous treatment on all subjects.
- Ensure no unauthorized persons are engaged in purchasing or solicitation of vendor pricing on behalf of Enersource.
- Ensure that no purchases are made from employees or their immediate families without prior approval of the President of Enersource.
- Ensure no significant purchases are transacted as out-of-pocket expenses.
- Declare/disclose immediately any conflicts of interest in writing to the EVP and Chief Financial Officer.

1.3 Limits to Purchases under $7,500

Some purchases are not permitted although they are within the $7,500 limit and include:

- Goods and Services covered by an existing purchase order.
- Purchases that are deliberately split to bring them below the $7,500 limit.

1.4 Processing of invoices under $7,500

Invoices for purchases under $7,500 and not paid for by the Corporate credit card should be forwarded to Accounts Payable. The Invoice must:

- Contain the appropriate general ledger account number including company number and business unit number.

- Be reviewed by the person who made the order to validate the accuracy of quantities and price and to verify delivery of the goods and/or services.

- Be signed and dated by the appropriate signing authority referring to Signing Authority Policy (#500-5).

2.0 PURCHASE OF GOODS AND SERVICES OVER $7,500

2.1 Requisitions for Goods or Services

Requisitions are required for all single purchases over $7,500, excluding the products and services listed in section 3.1 of this policy. The Purchasing department should be used for requesting competitive pricing where applicable. Requisitions must be processed as follows:

- The requisition must contain detailed specifications of the goods and/or services to be purchased including, if available, manufacturer's catalogue number, required date, etc.
- At least three quotes, excluding single source supply conditions, will be required for the requisition to be processed. The Purchasing Department may be requested to obtain quotes on behalf of the business unit. If the purchase is for more than $100,000, a formal tendering process must be undertaken by the Purchasing Department.

The requisition must be approved according to the signing authority levels. (See Signing Authority Policy (#500-5)).

- All purchases must have an approved budget or approval must be obtained in accordance with Signing Authority Policy (#500-5).

All requisitions are to be forwarded to the Purchasing Department for processing after the above requirements have been met. Any requisitions not completed correctly will be returned to the requisitioner for approvals/corrections. Failure to adhere to the policy and procedures may result in delayed delivery of goods and/or services.

2.2 Processing of Purchase Requisitions within Purchasing Department

Processing of Purchasing Requisitions within the Purchasing Department will be done according to internal procedures and in accordance with the Purchasing Policy. This can include, solicitation of at least three quotes, formal tendering, developing alliances with other purchasing authorities, or

developing alliances with suppliers. The Purchasing Department will keep the requisitioner informed of progress and will treat all purchases in the context of time being of the essence.

2.3 Receipting and Payment Approval for Purchases over $7,500

The supplier's invoice is to be used as the vehicle for receipting and arranging for payments for purchases over $7,500.

The invoices must be processed as follows where a Purchase Order has been issued:

- The invoice must be compared with the purchase order by the person signing the invoice.
- The invoice must be reviewed by the requisitioner to ensure the description, quantity, quality and price match between the items received the purchase order and the invoice. The requisitioner must sign that this check has been done and the items, as described, have been received.
- The invoice must be approved according to the Signing Authority Policy (#500-5) and forwarded to Accounts Payable for payment.
- Any differences between the purchase order and the invoice must be addressed:
  - Minor differences can be ignored if considered acceptable. These differences cannot exceed 5% of the purchase order price, up to a maximum of $7,500.
  - Adjustments beyond this limit require either a revised invoice matching the purchase order or an approved revision to the purchase order.

2.4 Purchases over $7,500 with No Purchase Order

There may be circumstances where goods and/or services have been supplied without a Purchase Order. In these situations a Purchase Requisition and Purchase Order are not to be issued after an invoice has been received. Instead, the invoice should be approved according to the Signing Authority Policy (#500-5) at the President or Vice President levels. The requisitioner must include in a note attached to the Invoice:

1. A statement that there is no Purchase Order; and,
2. An explanation of the reason for not having a Purchase Order.

The Invoice is to be sent to the Executive Vice President and Chief Financial Officer who will scrutinize the situation and if satisfied with the explanations will approve payment. After two violations of the policy, the Executive Vice President and Chief Financial Officer may take the invoice to the President for approval.

3.1 ITEMS NOT REQUIRING A PURCHASE REQUISITION

Certain goods, services and payments do not require a purchase requisition. Controls, other than approved Purchase Requisitions are in place for these items and must be followed:

Description	Control Process to be Followed
Annual Bond Rating Fees	Bond rating fees are to be approved by the EVP and Chief Financial officer.
Audit Expenses	External audit work and related fees are approved by the Audit Committee of the Board of Directors. The audit fee payment is approved by the EVP & CFO.
Banking Services	Banking Arrangements are made by the Treasurer, recommended by the VP, Finance and approved by the EVP & CFO. All banking fees are approved by the Treasurer.
Corporate/Social Responsibility	Payments for Corporate and social responsibility must be approved by the Treasurer or the EVP of the appropriate Enersource Company.
Customer Rebates	Rebates to customers must be signed in accordance with Signing Authority Policy #500-5.
Human Res.-EAP provider, Temporary Agency/Recruitment	A variety of fees are paid to external parties that are related to confidential information. Invoices for these services are to be signed by the appropriate Manager/Supervisor and HR Manager if applicable.
IESO/ Cost of Power payments	Invoices for IESO or other power providers are to be signed by the Settlements department and the appropriate VP and EVP.
Industry & Association Membership Dues & Fees	EDA, OEA, OEN, MBOT, CEA, ESA, etc. are approved by the President & CEO.
Insurance Premiums	Insurance arrangements are made by the Director, Internal Audit & Enterprise Risk and approved by the EVP and Chief Financial Officer.

enersource		CORPORATE POLICY	
SUBJECT	PURCHASING	NUMBER	500-2
DEPARTMENT	Finance	REVISED DATE	March 2012
REPLACES POL#	Policy No. 771	ORIGINAL DATE	June 2005

Description	Control Process to be Followed
Legal Services/Regulatory Costs	Legal Services are arranged and approved by the EVP & CFO and the requisitioning Manager in accordance with the Signing Authority Policy #500-5. Regulatory costs are to be approved by the Director, Regulatory Affairs.
Medicals	Medical arrangements are made by Human Resources and payments are approved by the Human Resources Management.
Office Supplies	All Office Supplies are to be purchased from Corporate Express, or the authorized office supply vendor. Office Services matches packing slips with goods received and arranges for payment.
Payroll Deduction/Union Dues Remittances	A variety of processes are in place for selecting the providers. Remittances are approved by the Treasurer.
Police	Payment for police service is approved one level above the level that requested the service and must, as a minimum, be approved by a manager.
Postage	Payment of postage charges is approved by the Treasurer.
Printing and Stationery	Requests for all printing and stationery must be made to Office Services who will arrange for supply. Payments are approved by Administrative Support Supervisor.
Right of way or Easements	Invoices are to be signed by the appropriate Manager and corresponding VP.
Semi-Annual Interest Payments on Bonds	Must be in accordance to the Wire Transfer protocols and approved by either the CFO or President and CEO.
Software License Fees and Annual Software Maintenance Fees	The contractual schedule of fees is approved in the process of acquiring the software. Invoices for license and annual maintenance fees are approved by Information Systems Management.
Tax Remittances	Tax remittances are approved by the VP, Finance.
Vehicle License Fees	Annual payment of fees is a legal requirement and invoices for license fees are approved by the Fleet Supervisor.
Water, Electricity, Gas and Telephones.	Payment for regular service of Water, Electricity and Gas at standard fees is approved by Facilities Management. Payment for regular Telephone services is approved by the Information Technology Manager.

enersource		CORPORATE POLICY	
SUBJECT	PURCHASING	NUMBER	500-2
DEPARTMENT	Finance	REVISED DATE	March 2012
REPLACES POL#	Policy No. 771	ORIGINAL DATE	June 2005

Continuation of Policy #500-2

APPROVAL LEVELS
NEW POLICIES AND REVISIONS

√	Title	Name	Division/Dept.	Signature	Date Approved
	Executive Vice President & CFO	Norm Wolff	Finance		03/28/2012
	President & CEO	Craig Fleming	Corporate		03/29/2012

All policies will be reviewed annually and revised by originating department.

APPROVED 2008 APPROVED 2009 APPROVED 2010 APPROVED 2011 APPROVED 2012

Number # SS-20_____

enersource

Single Source Procurement- Request for Authorization

Please fill out the following information and forward this report to the Purchasing Manager.

Product/Service Description Date: _____

_____

_____

_____

_____

Is this a product? _____ Service? _____ Both? _____
(For consulting services, approval must be given by the CEO)

Single Source Vendor name and address

_____

_____

_____

Value of Purchase per year $_____

Advise if a multi-year commitment and if so, how many years? _____

The following business conditions individually or in aggregate constitute a qualification for single source procurement. Please check the appropriate reason.

	1. Pre-requisite for technological compatibility or proprietary fit.
	2. Only one vendor for specific product or service within reasonable proximity.
	3. Exclusive rights of supply such as patents, copyrights, licenses or monopolies.
	4. Scarcity of supply of the specific requirement (goods and/or services) in the marketplace.
	5. Preservation of warranties.
	6. Quotations solicited with only one response.
	7. Emergency procurement.
	8. A vendor possesses specialized and unique products, knowledge, skills, expertise or experience.
	9. Customer demands the engagement of a specific vendor.
	10. Prevailing strategic alliance.
	11. Confidential and/or strategically sensitive engagements or acquisitions.

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Details regarding the single source procurement

_____
_____
_____
_____
_____
_____
_____
_____

One Time Purchase: Perpetual:

Is this single source item/service deemed critical to Enersource? _____
(If yes, a D&B report will be requested by the Purchasing Department)

Internal Business owner name (please print)_____

Internal Business owner signature_____

Division_____

Enersource Company_____

Approval Sign off:

Manager/Director Signature: _____
Date

Vice President Signature: _____
Date

Executive VP Signature: _____
(President & CEO if applicable) Date

Approval for; One time_____Perpetual_____Deny_____

CFO & Executive VP Signature_____
Date

Purchasing Manager sign-off_____
Date

Added to Report_____

enersource			CORPORATE POLICY
SUBJECT	SIGNING AUTHORITY	NUMBER	500-5
DEPARTMENT	Finance	REVISED DATE	March 2012
REPLACES POL#	Policy No. 102	ORIGINAL DATE	June 2005

POLICY

Authorities may be delegated as required in support of efficient operations while maintaining a high level of control over operations.

1.0 USE OF SIGNING AUTHORITIES

The following levels of authority are required for processing of all purchasing, business expenses, invoice and corporate credit card transactions. This initial phase in defining authorities for all transactions within Enersource Corporation may be amended from time to time as business conditions dictate.

2.0 SIGNING AUTHORITIES

Classification	Chair of the Board	President and CEO	Executive Vice President	Vice President	Director	Manager	Supervisor
Purchase Contract	No Authority	Unlimited – must be approved by two corporate signing officers (Please see attached signing officer Schedule)			No Authority	No Authority	No Authority
Lease	No Authority	Unlimited – must be approved by Chief Financial Officer and the President or Chief Operating Officer			No Authority	No Authority	No Authority
Purchase Requisition Requisitions for Consulting Services	No Authority	$250,000	No Authority	No Authority	No Authority	No Authority	No Authority

enersource		CORPORATE POLICY	
SUBJECT	SIGNING AUTHORITY	NUMBER	500-5
DEPARTMENT	Finance	REVISED DATE	March 2012
REPLACES POL#	Policy No. 102	ORIGINAL DATE	June 2005

Classification	Chair of the Board	President and CEO	Executive Vice President	Vice President	Director	Manager	Supervisor
Requisitions for Capital items not in Budget	No Authority	$2,000,000	$500,000	$50,000	No Authority	No Authority	No Authority
Requisitions where the Business Unit is over Budget	No Authority	$500,000	$150,000	$50,000	No Authority	No Authority	No Authority
All Other Requisitions	No Authority	Unlimited	$500,000	$150,000	$50,000	25,000	No Authority
Purchase Order							
Purchase Order supported by approved Purchase Requisition	No Authority	Unlimited	$500,000	No Authority	No Authority	No Authority except unlimited by Purchasing Manager	No Authority
Payments							
Purchase over $7,500 with Purchase Order	No Authority	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited
Purchase over $7,500 without Purchase Order	No Authority	Unlimited	One level above Purchase Requisition Authority plus CFO	One level above Purchase Requisition Authority plus CFO	No Authority	No Authority	No Authority
Power Bill from IMO	No Authority	Unlimited	No Authority except unlimited by CFO	No Authority	No Authority	No Authority	No Authority
Customer Rebates	No Authority	Unlimited	$150,000	$50,000	$25,000	$25,000	No Authority
Semi-Annual Interest Payments on Bonds	No Authority	Unlimited	No Authority except unlimited by CFO	No Authority except unlimited by CFO	No Authority	No Authority	No Authority

enersource		CORPORATE POLICY	
SUBJECT	SIGNING AUTHORITY	NUMBER	500-5
DEPARTMENT	Finance	REVISED DATE	March 2012
REPLACES POL#	Policy No. 102	ORIGINAL DATE	June 2005

Classification	Chair of the Board	President and CEO	Executive Vice President	Vice President	Director	Manager	Supervisor
CORPORATE CREDIT CARD ("CARD")							
Issue of Card to Employee	No Authority	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited	No Authority
APPROVAL OF CARD LIMITS ABOVE $7,500	No Authority	$100,000	$25,000	$15,000	10,000	No Authority	No Authority
Approval of Monthly Statement	No Authority	Unlimited	$25,000	$15,000	$10,000	$10,000	$7,500
Advances and Net Claim for Business Expenses not on the Credit Card	No Authority	Unlimited	$15,000	$15,000	$10,000	$5,000	$2,500
Board and President & CEO Expenses	Unlimited	No Authority	No Authority – except $7,500 by CFO	No Authority	No Authority	No Authority	No Author

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enersource		CORPORATE POLICY	
SUBJECT	SIGNING AUTHORITY	NUMBER	500-5
DEPARTMENT	Finance	REVISED DATE	March 2012
REPLACES POL#	Policy No. 102	ORIGINAL DATE	June 2005

Exceptions

Exceptions to the above authorities are:

1. Purchase Requisitions
   Some purchases do not require a purchase requisition. These exceptions are described in the Purchasing Policy and Procedure.

2. Authority Levels
   Exceptions to these prescribed levels of authority may arise from time to time and must be endorsed in writing by the President and CEO and/or the Board of Directors depending on the circumstances.

Temporary delegation of authority is appropriate for maintaining continuity of operations over short-term absences such as vacations. Such delegation can be positioned through a standing arrangement or on a contingent basis. A standing arrangement basis requires that employees with signing authority permanently delegate authority to a peer or direct report to cover all absences. Contingent delegation of authority will be assigned on case by case basis. In all cases delegation of authority must be approved by the delegate's superior.

The Purchasing Manager and the Treasurer must be notified in writing by the approving superior of any approved exceptions to this Policy and of all delegation of authority.

APPROVAL LEVELS
NEW POLICIES AND REVISIONS

√	Title	Name	Division/Dept.	Signature	Date Approved
	Executive Vice President & CFO	Norm Wolff	Finance		03/26/2012
	President & CEO	Craig Fleming	Corporate		03/26/12

All policies will be reviewed annually and revised by originating department.

APPROVED 2009 APPROVED 2010 APPROVED 2011 APPROVED 2012

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COMPANY SIGNING OFFICERS

Enersource Corporation

Officers

Norman Loberg	Chair of the Board
Craig Fleming	President and Chief Executive Officer
Norman Wolff	Executive Vice President and Chief Financial Officer
Jo Ann Morello	Vice President, Human Resources

Regulated Business

Enersource Hydro Mississauga Inc.

Officers

Patrick Quinn	Chair
Dan J. Pastoric	Executive Vice President, Chief Operating Officer, Secretary & Treasurer
Raymond Rauber	Vice President, Engineering and Operations
James Macumber	Vice President, Finance

Non-Regulated Businesses

Enersource Services Inc.

Officers

Craig Fleming	President
Norman Wolff	Secretary
Jo Ann Morello	Vice President

Enersource Hydro Mississauga Services Inc.

Officers

Craig Fleming	President
Norman Wolff	Secretary
Jo Ann Morello	Vice President

Enersource Technologies Inc.

Officers

Craig Fleming	President
Norman Wolff	Secretary
Jo Ann Morello	Vice President

Depreciation/Amortization/Depletion

This exhibit provides a summary of depreciation expense for the historical years (2008-2011), the 2012 Bridge Year, the 2013 Test Year, and the incremental capital and return year ("ICR Year"), 2014.

Under CGAAP, Enersource followed the guidelines provided in the OEB's 2006 Electricity Distribution Rate Handbook ("EDR Handbook") and the Accounting Procedures Handbook for Electric Distribution Utilities ("APH")[1]. This method was permitted under CGAAP, as the prescribed useful lives of the APH represented the "estimated service lives" of assets under the regulatory framework.

As part of its adoption of IFRS, Enersource evaluated its assets to determine a more appropriate level of componentization. IFRS requires separate deppreciation of an item of Property, Plant, and Equipment ("PPE"), or an intangible asset, which has a cost that is significant in relation to the total cost of the item and for which different depreciation methods or rates are appropriate.

This evaluation of assets was undertaken according to a study prepared by Kinectrics Inc., as engaged by Enersource and four other distributors, entitled *Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets*, dated December 10, 2009. For reference purposes, the short name is "Enersource's Useful Lives Study" and is filed at Exhibit 2 Tab 1 Schedule 1 Appendix 1. Because of the Enersource's Useful Lives Study, additional components or asset groups were identified.

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[1] Enersource has followed the Board's *Accounting Procedures Handbook for Electric Distribution Utilities*, revised July 31, 2007 ("APH"). On March 28, 2012, the Board released the *Accounting Procedures Handbook for Electricity Distributors* ("new APH"). Enersource is reviewing the new APH to confirm no changes to the Application are required.

Therefore as of January 1, 2011, Enersource revised the useful lives of its depreciable assets. The revised estimates were adopted prospectively and extended the lives of many depreciable assets, hence resulting in a decrease of depreciation expense for each year. For further details refer to Exhibit 2 Tab1.

Table 1 below shows the asset groupings and the useful lives of capital assets before and after the change in the componentization structure.

Table 1: Useful Lives of Enersource's Assets (years)

CGAAP Asset Category	Previous Useful Life (years)	IFRS Asset Category	Revised Useful Life (years)
Land	n/a	Land	n/a
Easements	n/a	Easements	n/a
Building & Fixtures – Brick, Stone, Concrete & Steel	50-60	Building & Fixtures – Brick, Stone, Concrete & Steel	60
Building & Fixtures – Other Construction	25	Building & Fixtures – Other Construction	20
General Equipment	10	General Equipment	10
Distribution station equipment	30	Distribution station equipment	40
Overhead Distribution System	25	Fault Indicators	10
		Wood Pole System	45
		Concrete Pole System	55
		Overhead Switches / Fuses	40
		Scadamate/ Reclosures	25
Transformer Systems	25	Pole-mounted Transformer System	45
		Pad mounted Transformer System	35
Underground Distribution System	25	Air Insulated switchgear	25
		Solid Dielectric Switchgear	35
		Underground Cable System	40
		Duct & Foundations	50
		Underground Accessories	20
SCADA/Protection and DC Systems	15	SCADA/Protection and DC Systems	15
Meters	25	Meters	25
Smart Meters	15	Smart Meters	15
Rolling stock - Automobiles	4	Rolling stock - Automobiles	4
Rolling stock - Trucks under 3 Tons	5	Rolling stock - Pick up Trucks & Vans	5
Rolling stock - Trucks over 3 Tons	8	Rolling stock - Single Buckets, Dump trucks & Cranes	8
		Rolling stock - Double Buckets & RBDs	12
Rolling stock - Service Equipment	8	Rolling stock - Trailers & Off Road Equipment	15
Major Tools	10	Major Tools	10
Computer Hardware	5	Computer Hardware - Desktops & Laptops	3
		Computer Hardware - Networking & Printing	5
		Computer Hardware - Corporate/Enterprise	10
Computer Software	5	Minor Software- Out of Box	2
		System Software - Office Automation & Collaboration	5
Major Software - Corporate/Enterprise	10	Major Software - Corporate/Enterprise	10

Enersource uses the half year rule for calculating depreciation of capital additions during the year of addition for all assets. Depreciation is calculated on a straight-line basis over the estimated service lives of assets as shown in Table 1 above.

Construction in progress, capital contributions for work in progress, and software in development include assets that are not currently in use and therefore are not depreciated.

Enersource currently has not recorded any asset retirement obligations and has not forecasted any amounts for 2012 to 2014.

Enersource has not completed Appendix 2-M, as it is a simplified approach in calculating the depreciation expense and the requested information is already provided in Exhibit 2 Tab 1 Schedule 1 Appendix 2-B, "Fixed Asset Continuity Schedule".

Table 2 below summarizes the depreciation expense from 2008 Board-approved to 2010 actuals under CGAAP. These amounts are the same as the additions in the accumulated depreciation as presented for each year in Exhibit 2 Tab 1 Schedule 1 Appendix 2-B.

Table 2: CGAAP Depreciation Expense ($000s)

Description	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual
Land and Buildings	$ (297)	$ (334)	$ (363)	$ (404)
TS Primary Above 50		$ -	$ -	$ -
Distribution Station	$ (2,289)	$ (2,330)	$ (2,464)	$ (2,593)
Poles, Wires	$ (23,553)	$ (23,818)	$ (24,862)	$ (26,050)
Line Transformers	$ (2,648)	$ (2,673)	$ (2,660)	$ (2,625)
Services and Meters	$ (1,523)	$ (1,304)	$ (1,243)	$ (1,277)
General Plant		$ -	$ -	$ -
Equipment	$ (2,475)	$ (2,113)	$ (2,278)	$ (2,317)
IT Assets	$ (3,114)	$ (2,519)	$ (2,241)	$ (3,064)
Other Distribution Assets	$ (893)	$ (840)	$ (903)	$ (991)
Customer Contributions	$ 2,684	$ 2,970	$ 2,995	$ 3,068
Closing Balance w/o Smart Meters	**$ (34,108)**	**$ (32,961)**	**$ (34,018)**	**$ (36,253)**
Smart meters depreciation in rate rider	$ -	$ (886)	$ (1,317)	$ (1,860)
Closing Balance	**$ (34,108)**	**$ (33,847)**	**$ (35,335)**	**$ (38,114)**

Table 3 below illustrates the actual depreciation expense for 2011 under IFRS and the nature of each adjustment to the depreciation expense for the year.

Table 3: Depreciation Expense IFRS 2011 Actual ($000s)

Description	IFRS Actual 2011	Opening Write-off	Early Derecognition	IFRS Total Depreciation	Stranded Meters Depreciation	MIFRS 2011 Total Depreciation
Land and Buildings	$ (532)		$ -	$ (532)		$ (532)
TS Primary Above 50	$ -		$ -	$ -		$ -
Distribution Station	$ (1,689)		$ (93)	$ (1,782)		$ (1,782)
Poles, Wires	$ (9,625)	$ (807)	$ (1,312)	$ (11,744)		$ (11,744)
Line Transformers	$ (2,349)		$ (454)	$ (2,803)		$ (2,803)
Services and Meters	$ (679)		$ -	$ (679)	$ (1,072)	$ (1,751)
General Plant	$ -		$ -	$ -		$ -
Equipment	$ (2,151)		$ -	$ (2,151)		$ (2,151)
IT Assets	$ (3,282)	$ (58)	$ -	$ (3,340)		$ (3,340)
Other Distribution Assets	$ (968)	$ (449)	$ -	$ (1,417)		$ (1,417)
Customer Contributions	$ 51		$ -	$ 51		$ 51
Closing Balance w/o Smart Meters	**$ (21,224)**	**$ (1,313)**	**$ (1,859)**	**$ (24,396)**	**$ (1,072)**	**$ (25,468)**
Smart meters depreciation in rate rider	$ (2,365)	$ -	$ -	$ (2,365)	$ -	$ (2,365)
Closing Balance	**$ (23,589)**	**$ (1,313)**	**$ (1,859)**	**$ (26,761)**	**$ (1,072)**	**$ (27,833)**

The amounts shown in Table 3 in the column “IFRS Actual 2011” represent the depreciation expense of opening balances of net capital assets and the new

additions for the year. These values are the same as the additions in the accumulated depreciation continuity as presented in Exhibit 2 Tab 1 Schedule 1 Appendix 2-B for 2011. The actual amount of depreciation in 2011 under IFRS was $10,734 lower than the depreciation expense under CGAAP due to the change of useful lives of assets.

The amounts shown in Table 3, column "Opening Write-off", represent the one-time write- off of net book value relating to assets that in IFRS have useful lives shorter than in CGAAP. This write-off is mainly related to underground accessories, fault indicators, SCADA, and other supervisory control equipment.

The amounts presented in Table 3, column "Early Derecognition", represent the net book value ("NBV") of assets that have been removed prematurely from the system (before reaching their useful lives). Enersource has included the NBV of the disposed assets as depreciation expense for each period based on the OEB guidelines in the Board Report[2]. For further details, refer to Exhibit 2 Tab1 Schedule 1.

The amount shown in Table 3, column "Stranded Meters Depreciation", represents the 2011 depreciation expense of stranded meters that have been deferred to USofA account 1555. The offset of this adjustment is the reduction of account 1555 in order to account for the continuous depreciation of these assets

Table 4 below illustrates the forecast depreciation expense for 2012 and the nature of each adjustment to this expense for the year.

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[2] OEB proceeding EB-2008-0408 resulted in the issuance of the *Report of the Board, Transition to IFRS*, on July 28, 2009, subsequently amended November 8, 2010, and March 15, 2011, and then appended by an addendum, dated June 13, 2011, (collectively, the "Board Report").

Table 4: Depreciation Expense IFRS 2012 Forecast ($000s)

Description	IFRS 2012 Forecast	Early Derecognition	Total Depreciation	Stranded Meters Depreciation	MIFRS 2012 Total Depreciation
Land and Buildings	$ (933)	$ -	$ (933)		$ (933)
TS Primary Above 50	$ -	$ -	$ -		$ -
Distribution Station	$ (1,993)	$ (97)	$ (2,090)		$ (2,090)
Poles, Wires	$ (9,839)	$ (1,343)	$ (11,182)		$ (11,182)
Line Transformers	$ (2,441)	$ (470)	$ (2,911)		$ (2,911)
Services and Meters	$ (641)	$ -	$ (641)	$ (1,071)	$ (1,712)
General Plant	$ -	$ -	$ -		$ -
Equipment	$ (2,215)	$ -	$ (2,215)		$ (2,215)
IT Assets	$ (3,480)	$ -	$ (3,480)		$ (3,480)
Other Distribution Assets	$ (975)	$ (14)	$ (989)		$ (989)
Customer Contributions	$ 150	$ -	$ 150		$ 150
Closing Balance w/o Smart Meters	**$ (22,369)**	**$ (1,924)**	**$ (24,292)**	**$ (1,071)**	**$ (25,363)**
Smart meters depreciation in rate rider	$ (2,699)		$ (2,699)		$ (2,699)
Closing Balance	**$ (25,068)**	**$ (1,924)**	**$ (26,991)**	**$ (1,071)**	**$ (28,062)**

The amounts shown in Table 4 in the column "IFRS 2012 Forecast" represent the depreciation expense of opening balances of net capital assets and the new additions for the year. These values are the same as the additions in the accumulated depreciation continuity as presented in Exhibit 2 Tab 1 Schedule 1 Appendix 2-B for 2012. The forecasted amount of depreciation in 2012 under IFRS is projected to be $11,030 lower than the depreciation expense that would have been forecasted under CGAAP.

The amounts shown in Table 4, column "Early Derecognition", represent the NBV of assets that have been removed prematurely from the system (before reaching their useful lives). Enersource has included the NBV of the disposed assets as depreciation expense for each period based on the Board Report.

The amount shown in Table 4, column "Stranded Meters Depreciation", represents the 2012 depreciation expense of stranded meters that have been

deferred to USofA account 1555. The offset of this adjustment is the reduction of account 1555 in order to account for the continuous depreciation of these assets.

Variance Analysis - 2012 IFRS Bridge Year Depreciation Forecast versus 2011 IFRS Actual Depreciation Expense

Enersource's forecasted 2012 Bridge Year depreciation expense is $229 higher than 2011 actual depreciation expense due to:

- $402 higher depreciation expense related to building, facilities, and equipment mainly due to the acquisition and retrofit of the new administration office;
- $1,141 higher depreciation in distribution system assets due to higher net capital assets; and
- Offsetting the increases in depreciation expense is the $1,313 prior year one-time write-off of assets, as part of opening balances transformation from CGAAP to IFRS.

Table 5 below illustrates the forecast depreciation expense for 2013 and 2014 and the nature of the additions to this expense for each year.

Table 5: Depreciation Expense IFRS, 2013 and 2014 Forecast

Description	IFRS 2013 Forecast	Early Derecognition	IFRS 2013 Total Dep	IFRS 2014 Forecast	Early Derecognition	IFRS 2014 Total Dep
Land and Buildings	$ (1,316)	$ -	$ (1,316)	$ (1,527)	$ -	$ (1,527)
TS Primary Above 50	$ -	$ -	$ -	$ -	$ -	$ -
Distribution System	$ (2,135)	$ (99)	$ (2,234)	$ (2,216)	$ (102)	$ (2,319)
Poles, Wires	$ (10,209)	$ (1,383)	$ (11,592)	$ (10,716)	$ (1,424)	$ (12,140)
Line Transformers	$ (2,525)	$ (484)	$ (3,009)	$ (2,523)	$ (499)	$ (3,022)
Services and Meters	$ (3,494)	$ -	$ (3,494)	$ (3,577)	$ -	$ (3,577)
General Plant	$ -	$ -	$ -	$ -	$ -	$ -
Equipment	$ (2,340)	$ -	$ (2,340)	$ (2,631)	$ -	$ (2,631)
IT Assets	$ (3,974)	$ -	$ (3,974)	$ (4,265)	$ -	$ (4,265)
Other Distribution Assets	$ (1,032)	$ (15)	$ (1,047)	$ (1,125)	$ (15)	$ (1,140)
Customer Contributions	$ 232	$ -	$ 232	$ 317	$ -	$ 317
Closing Balance	**$ (26,791)**	**$ (1,981)**	**$ (28,773)**	**$ (28,264)**	**$ (2,041)**	**$ (30,305)**

The amounts shown in Table 5, columns “IFRS 2013 Forecast” and “IFRS 2014 Forecast” represent the depreciation expense of opening balances of net capital assets and the new additions for each year. These values are the same as the additions in the accumulated depreciation continuity as presented in Exhibit 2 Tab 1 Schedule 1 Appendix 2-B for 2013 and 2014, respectively.

The amounts shown in Table 5, columns “Early Derecognition”, represent the NBV of assets that have been removed prematurely from the system (before reaching their useful lives) for each respective year.

Variance Analysis - 2013 IFRS Test Year Depreciation Forecast versus 2012 IFRS Bridge Year Depreciation Forecast

Depreciation expense is forecasted to be $711 higher in 2013 compared to 2012 depreciation expense due to:

- $382 higher depreciation in building, facilities, and equipment due to prior year acquisition of the new administration office, and improvements to other facilities;

- $1,399 higher depreciation in distribution system assets due to higher net assets as well as lower retirements than prior year; and

- Offsetting the increases in depreciation expense is the $1,071 lower depreciation due to prior year depreciation of stranded meters.

Variance Analysis - 2014 IFRS Test Year Depreciation Forecast versus 2012 IFRS Bridge Year Depreciation Forecast

Depreciation expense is forecasted to be $1,532 higher in 2014 compared to 2013 depreciation expense due to higher net capital assets values for all the asset categories.

Taxes (Payments in Lieu of Taxes ("PILs"), Capital Tax, and Property Taxes)

Introduction

Enersource is required to make Payments in Lieu of Taxes ("PILs") based on its taxable income. Enersource has included a PILs amount of $2,981 for 2013 to be included in the revenue requirement filed at Exhibit 1, Tab 2, Appendix 2-C (i). The model used to calculate the forecasted 2013 PILs amount is based on the Board's Income Tax/PILs Workform ("Tax Model") for 2013 rate rebasing applications.

Enersource created a separate 2014 PILs Tax Model based on the same assumptions and methodologies as the Board's Tax Model. The only items updated in Enersource's 2014 Tax Model relate to the increase in fixed assets in 2014, including depreciation expense, capital cost allowance, and deemed net income before taxes. Enersource has also used the currently enacted 2014 corporate income tax rate of 25%[1]. The PILs amount calculated in the 2014 Tax Model is $3,558 and is included in the 2014 revenue requirement filed at Exhibit 1 Tab 2 Appendix 2-C(ii).

[1] Enersource has not adjusted the corporate income tax rates for any proposed legislative changes. If income tax rate changes are enacted, Enersource will update its Tax Models and the corresponding impacts on revenue requirement.

Prudent Management of Taxes

Enersource prudently manages its tax liabilities in an effort to minimize its effective tax rate. Available tax credits are utilized when applicable in order to reduce the amount of PILs paid each year.

Regulatory Taxes Expense Methodology

The PILs amount to be included in the revenue requirement are based upon the general principles and methodologies as described in the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications and the Tax Model.

Disclosure of PILs Tax Administration and Tax Rulings

Enersource has not received any specific tax rulings that are inconsistent with the general principles and methodologies of the Tax Model.

Tax Re-Assessements

The Ontario Ministry of Revenue ("Revenue") has completed its review of Enersource's 2001 to 2006 taxation years. Methodologies approved by Revenue as part of its audit reassessments have been incorporated in calculating the forecasted PILs amount.

Non-Recoverable and Disallowed Expenses

There are no non-recoverable or disallowed expenses included in the 2013 Test Year amounts. As a result, there are no such adjustments required to the PILs amount calculated by the Tax Model.

Capital Tax

The Ontario capital tax rate was eliminated effective July 1, 2010; therefore there is no provision for capital taxes in the test year.

Loss Carry-Forward Amounts

Enersource does not have any non-capital loss carry-forward amounts at the end of 2011 and does not anticipate having any available for 2013.

As of the end of 2011, Enersource has capital loss carry-forward amounts of $257. The capital loss carry-forward was generated from realized foreign exchange losses.

Undepreciated Capital Cost and Capital Cost Allowance ("CCA")

Enersource has claimed the maximum CCA deduction as calculated in the Tax Model.

Regulatory Tax Treatment of Eligible Capital Expenditure ("ECE")

Enersource has claimed the maximum ECE deduction as calculated in the Tax Model. The opening cumulative eligible capital balance represents the October 1, 2001 fair market value bump that was created when the PILs regime came into effect, net of the cumulative ECE deduction that has already been claimed. Also included in the opening balance is the cost of land easements in 2010 and 2011. Enersource has forecasted an acquisition of land easements in 2013 for $2,000 relating to the Churchill Meadows TS.

Interest Deduction

Forecast interest expense is less than the deemed interest expense calculated by the Tax Model. As a result, the deemed interest has been deducted in calculating taxable income.

Capitalized Interest

Enersource has not capitalized interest incurred on construction work in progress (allowance for funds used during construction) for tax purposes; however, interest is capitalized for accounting purposes.

Ontario Corporate Minimum Tax

Ontario Corporate Minimum Tax is not applicable to Enersource, as calculated in the Tax Model.

Non-Distribution Elimination

Enersource has excluded all non-distribution costs and revenues.

Tax Credits

In prior years, Enersource claimed tax credits relating to the Federal Apprenticeship Job Creation Tax Credit, the Ontario Apprenticeship Training Credit, and the Ontario Co-Operative Education Tax Credit. Enersource has forecasted tax credits of $200 relating to these programs in the calculation of the 2013 PILs amount. Table 1 below details the apprenticeship and co-operative education tax credits received in prior years.

Table 1: Apprenticeship and Co-operative Education Tax Credit

Tax Return	2007	2008	2009	2010			
Year Recorded in Financial Statements	2008	2009	2010	2011	2012	2013	2014
Apprenticeship	44	70	145	161	140	140	140
Co-op	18	21	67	66	60	60	60
	62	91	212	227	200	200	200

Enersource has also included a forecasted tax credit amount relating to Scientific Research and Experimental Development ("SR&ED") expenditures. Enersource

expects its SR&ED claim to decrease from prior years due to the completion of SR&ED applicable projects relating to Supervisory Control and Data Acquisition ("SCADA"), Integrated Operating Model ("IOM") and the implementation of the customer care and billing software. Table 2 below shows the SR&ED credits received in prior years.

Table 2: SR&ED Tax Credit

Tax Return	2007	2008	2009	2010			
Year Recorded in Financial Statements	2008	2009	2010	2011	2012	2013	2014
SR&ED	75	626	598	585	200	200	200

Property Taxes

The Tax Model addresses corporate income taxes but not property tax. Property tax is included as part of OM&A costs discussed in Exhibit 4 Tab 1 Schedules 3 and 10, Engineering & Operations and Facilities Management Services, respectively.

Capital Leases

No leases capitalized for accounting purposes are deducted for tax purposes in the Tax Model.

Tax Model

The 2013 Tax Model is enclosed in Exhibit 4 Tab 7 Schedule 1 Appendix 1. At the time of filing the Application, there have been no changes in legislation of the tax rates or rules assumed in the 2013 Tax Model.

Enersource has created a separate model, in Exhibit 4 Tab 7 Schedule 1 Appendix 2, for the 2014 PILs amount based on the assumptions and methodologies in the Board's Tax Model.

Tax Payable Filings

PILs paid by Enersource, based on the assessed tax returns, are provided in Table 3 below. PILs include income and capital taxes only.

Table 3: Summary of PILs by Year per Tax Return

	2008 Approved	2008 Actual	2009 Actual	2010 Actual
Income Tax	6,423	10,263	4,943	4,535
Capital Tax	1,163	1,232	1,144	385
Total PILs	7,586	11,495	6,087	4,920

PILs, as calculated in the Tax Model, are provided in Table 4.

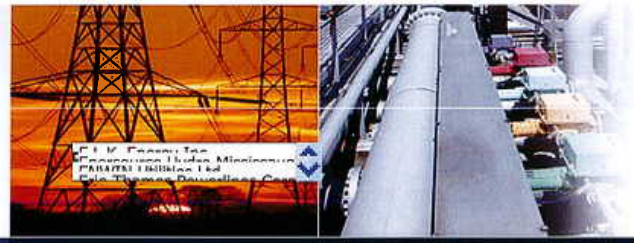
Table 4: PILs per Tax Model

	2011 Historic	2012 Bridge	2013 Test	2014 Test
Income Tax	4,736	–	2,981	3,558
Capital Tax	–	–	–	–
Total PILs	4,736	–	2,981	3,558

The decrease in PILs from 2008 to 2012 is primarily due to the decrease in income tax rates, the elimination of provincial capital tax, and the difference between tax and book treatment of certain costs. The decrease in PILs in 2012 is also attributable to a decrease in net income before taxes.

PILs increases in 2013 mainly because of the increase in net income before taxes due to the increased return as proposed in this Application, partially offset by the difference between tax and book treatment of certain costs.

The increase in PILs in 2014 is attributable to increases in net income before taxes and depreciation, partially offset by an increase in the capital cost allowance deduction. These changes are a direct result of the increase in rate base. The PILs increase was also partially offset by a decrease in corporate income tax rates.



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Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Choose Your Utility:

Application Contact Information

Name:	Martin Sultana
Title:	Rates Manager
Phone Number:	905-283-4255
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Copyright

This Workbook Model is protected by copyright and is being made available to you solely for the purpose of preparing or reviewing your PILs or Income Taxes. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

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Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

Data Input Sheet - Applicant's Rate Base

Rate Base			**$**	**626,888,284**	

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	$	25,075,531	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	351,057,439	*X = S * U*
Deemed Equity %	40.00%	V	$	250,755,314	*Y = S * V*
Short Term Interest Rate	2.08%	Z	$	521,571	*AC = W * Z*
Long Term Interest	5.09%	AA	$	17,873,738	*AD = X * AA*
Return on Equity (Regulatory Income)	9.12%	AB	**$**	**22,868,885**	*AE = Y * AB*
Return on Rate Base			**$**	**41,264,194**	*AF = AC + AD + AE*

Questions that must be answered

	Historic	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes	Yes	Yes
2. Does the applicant have any SRED Expenditures?	Yes	Yes	Yes
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	Yes	Yes	Yes
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Tax Rates & Exemptions

Tax Rates Federal & Provincial As of March 22, 2011	Effective ################	Effective ################	Effective ################	Effective ################	
Federal income tax					
General corporate rate	38.00%	38.00%	38.00%	38.00%	
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%	
	16.50%	15.00%	15.00%	15.00%	(refer to Note 1)
Ontario income tax	11.75%	11.25%	10.50%	10.00%	
Combined federal and Ontario	28.25%	26.25%	25.50%	25.00%	
Federal & Ontario Small Business					
Federal small business threshold	500,000	500,000	500,000	500,000	
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	
Federal small business rate	11.00%	11.00%	11.00%	11.00%	
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	

NOTES:

1. Federal Budgets of March 22, 2011 and June 6, 2011 reaffirmed the corporate tax rate reductions to 16.5% in 2011 and 15% in 2012.

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Regulated Historic Year
1	Distribution System - post 1987	302,461,143		302,461,143
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	168,590		168,590
2	Distribution System - pre 1988	33,004,343		33,004,343
8	General Office/Stores Equip	5,189,929		5,189,929
10	Computer Hardware/ Vehicles	4,516,974		4,516,974
10.1	Certain Automobiles	174,593		174,593
12	Computer Software	2,411,641		2,411,641
13 1	Lease # 1			0
13 2	Lease #2			0
13 3	Lease # 3			0
13 4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			0
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment			0
45	Computers & Systems Software acq'd post Mar 22/04	96,619		96,619
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			0
47	Distribution System - post February 2005	195,418,438		195,418,438
50	Data Network Infrastructure Equipment - post Mar 2007	1,230,715		1,230,715
52	Computer Hardware and system software			0
95	CWIP	3,680,417		3,680,417
10.1	Certain Automobiles	9,883		9,883
10.1	Certain Automobiles	9,883		9,883
3	Buildings - Pre 1988	2,039,610		2,039,610
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	550,412,778	0	550,412,778

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**15,584,178**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	296,669			
Other Adjustments	31,735			
Subtotal	328,404	x 3/4 =	246,303	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			246,303	**246,303**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**15,830,481**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		**0**
Cumulative Eligible Capital Balance				**15,830,481**
Current Year Deduction		15,830,481	x 7% =	**1,108,134**
Cumulative Eligible Capital - Closing Balance				**14,722,348**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
			0
			0
			0
Total	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts	115,952		115,952
Accrued Employee Future Benefits:	4,699,316		4,699,316
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs	160,000		160,000
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	4,975,268	0	4,975,268

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Schedule 7-1 Loss Carry Forward - Histroic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic	257,624		257,624

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Adjusted Taxable Income - Historic Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	21,928,000		21,928,000
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	36,771,788		36,771,788
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112			0
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121			0
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements- balance at end of year	126	4,975,268		4,975,268
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216	245,329		245,329
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
Non-deductible fitness reimbursement	294			0
	295			0
ARO Accretion expense				0

Capital Contributions Received (ITA 12(1)(x))		4,942,405		4,942,405
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received		811,898		811,898
				0
				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**47,746,688**	**0**	**47,746,688**

Deductions:				
Gain on disposal of assets per financial statements	401	156,927		156,927
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	36,790,824		36,790,824
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	1,108,134		1,108,134
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	4,670,538		4,670,538
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received		4,942,405		4,942,405
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)		438,476		438,476
Overhead burdens		2,858,394		2,858,394
Allowance for Funds Used During Construction		400,115		400,115
				0
				0
				0
				0
				0
Total Deductions		**51,365,813**	**0**	**51,365,813**
Net Income for Tax Purposes		**18,308,875**	**0**	**18,308,875**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**18,308,875**	**0**	**18,308,875**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.
PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

							Wires Only	
Regulatory Taxable Income							$ 18,308,875	A
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.75%	B	$ 2,151,293	C = A * B			
Small business credit	Ontario Small Business Threshold	$ 500,000	D					
	Rate reduction (negative)	-7.25%	E	-$ 36,250	F = D * E			
Ontario Income tax							$ 2,115,043	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.55%	K = J / A			
	Federal tax rate			16.50%	L			
	Combined tax rate						28.05%	M = L + L
Total Income Taxes							$ 5,136,007	N = A * M
Investment Tax Credits							$ 400,000	O
Miscellaneous Tax Credits								P
Total Tax Credits							$ 400,000	Q = O + P
Corporate PILs/Income Tax Provision for Bridge Year							$ 4,736,007	R = N - Q

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Schedule 8 CCA - Bridge Year

Class	Class Description	UCC Regulated Historic Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	Bridge Year CCA	UCC End of Bridge Year
1	Distribution System - post 1987	$ 302,461,143	$ 17,088,176		$ 319,549,319	$ 8,544,088	$ 311,005,231	4%	$ 12,440,209	$ 307,109,110
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 168,590			$ 168,590	$ -	$ 168,590	6%	$ 10,115	$ 158,475
2	Distribution System - pre 1988	$ 33,004,343			$ 33,004,343	$ -	$ 33,004,343	6%	$ 1,980,261	$ 31,024,082
8	General Office/Stores Equip	$ 5,189,929	$ 1,119,320		$ 6,309,249	$ 559,660	$ 5,749,589	20%	$ 1,149,918	$ 5,159,331
10	Computer Hardware/ Vehicles	$ 4,516,974	$ 1,711,733	-$ 309,000	$ 5,919,707	$ 701,367	$ 5,218,341	30%	$ 1,565,502	$ 4,354,205
10.1	Certain Automobiles	$ 174,593			$ 174,593	$ -	$ 174,593	30%	$ 52,378	$ 122,215
12	Computer Software	$ 2,411,641	$ 4,400,791		$ 6,812,432	$ 2,200,396	$ 4,612,037	100%	$ 4,612,037	$ 2,200,396
13 1	Lease # 1				$ -	$ -	$ -		$ -	$ -
13 2	Lease #2				$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3				$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4				$ -	$ -	$ -		$ -	$ -
14	Franchise				$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable				$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment				$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment				$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 96,619			$ 96,619	$ -	$ 96,619	45%	$ 43,479	$ 53,140
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)				$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 195,418,438	$ 33,362,587		$ 228,781,025	$ 16,681,294	$ 212,099,732	8%	$ 16,967,979	$ 211,813,046
50	Data Network Infrastructure Equipment - post Mar 2007	$ 1,230,715	$ 1,360,481		$ 2,591,196	$ 680,241	$ 1,910,956	55%	$ 1,051,026	$ 1,540,170
52	Computer Hardware and system software				$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 3,680,417	-$ 100,840		$ 3,579,577	$ -	$ 3,579,577	0%	$ -	$ 3,579,577
10.1	Certain Automobiles	$ 9,883			$ 9,883	$ -	$ 9,883	30%	$ 2,965	$ 6,918
10.1	Certain Automobiles	$ 9,883			$ 9,883	$ -	$ 9,883	30%	$ 2,965	$ 6,918
3	Buildings - Pre 1988	$ 2,039,610			$ 2,039,610	$ -	$ 2,039,610	5%	$ 101,981	$ 1,937,630
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
					$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 550,412,778	$ 58,942,248	-$ 309,000	$ 609,046,026	$ 29,367,044	$ 579,678,982		$ 39,980,812	$ 569,065,214

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Schedule 10 CEC - Bridge Year

Cumulative Eligible Capital				14,722,348
Additions				
Cost of Eligible Capital Property Acquired during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			0	0
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				14,722,348
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	x 3/4 =		0

Cumulative Eligible Capital Balance			14,722,348
Current Year Deduction	14,722,348	x 7% =	1,030,564
Cumulative Eligible Capital - Closing Balance			13,691,783

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	115,952		115,952	164,048		280,000	164,048	
Accrued Employee Future Benefits:	4,699,316		4,699,316	413,844		5,113,160	413,844	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	160,000		160,000		60,000	100,000	-60,000	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	4,975,268	0	4,975,268	577,892	60,000	5,493,160	517,892	0

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Schedule 7-1 Loss Carry Forward - Bridge Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total
Actual Historical	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	Total
Actual Historical	257,624
Application of Loss Carry Forward to reduce taxable income in Bridge Year	
Other Adjustments Add (+) Deduct (-)	
Balance available for use in Test Year	257,624
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	257,624

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Total for Regulated Utility
Income before PILs/Taxes	A	11,781,000
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	28,062,224
Amortization of intangible assets	105	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves deducted in prior year	125	0
Reserves from financial statements- balance at end of year	126	5,493,160
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	86,810
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions		
Interest Expensing on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		2,906,700
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		400,000
Total Additions		36,948,894
Deductions:		

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Adjusted Taxable Income - Bridge Year

Gain on disposal of assets per financial statements	401	161,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	39,980,812
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	1,030,564
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current year	413	0
Reserves from financial statements - balance at beginning of year	414	4,975,268
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		2,906,700
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		438,477
Allowance for Funds Used During Construction		543,638
Total Deductions		50,036,460
Net Income for Tax Purposes		-1,306,566
Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		-1,306,566

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

PILs Tax Provision - Bridge Year

							Wires Only	
Regulatory Taxable Income							-$ 1,306,566	A
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	4.50%	B	$	-	C = A * B		
Small business credit	Ontario Small Business Threshold	$ -	D					
	Rate reduction	-6.75%	E	$	-	F = D * E		
Ontario Income tax							$ -	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				0.00%	K = J / A		
	Federal tax rate				0.00%	L		
	Combined tax rate						0.00%	M = L + L
Total Income Taxes							$ -	N = A * M
Investment Tax Credits							$ 400,000	O
Miscellaneous Tax Credits								P
Total Tax Credits							$ 400,000	Q = O + P
Corporate PILs/Income Tax Provision for Bridge Year							$ -	R = N - Q

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 307,109,110	7,195,855		$ 314,304,965	$ 3,597,928	$ 310,707,037	4%	$ 12,428,281	$ 301,876,683
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 158,475			$ 158,475	$ -	$ 158,475	6%	$ 9,508	$ 148,968
2	Distribution System - pre 1988	$ 31,024,082			$ 31,024,082	$ -	$ 31,024,082	6%	$ 1,861,445	$ 29,162,637
8	General Office/Stores Equip	$ 5,159,331	1,322,425		$ 6,481,756	$ 661,213	$ 5,820,544	20%	$ 1,164,109	$ 5,317,647
10	Computer Hardware/ Vehicles	$ 4,354,205	1,722,711	-318,270	$ 5,758,646	$ 702,221	$ 5,056,425	30%	$ 1,516,928	$ 4,241,718
10.1	Certain Automobiles	$ 122,215	67,800		$ 190,015	$ 33,900	$ 156,115	30%	$ 46,835	$ 143,181
12	Computer Software	$ 2,200,396	3,322,829		$ 5,523,225	$ 1,661,415	$ 3,861,810	100%	$ 3,861,810	$ 1,661,415
13 1	Lease # 1	$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 53,140			$ 53,140	$ -	$ 53,140	45%	$ 23,913	$ 29,227
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 211,813,046	29,719,227		$ 241,532,273	$ 14,859,614	$ 226,672,660	8%	$ 18,133,813	$ 223,398,461
50	Data Network Infrastructure Equipment - post Mar 2007	$ 1,540,170	769,199		$ 2,309,369	$ 384,600	$ 1,924,770	55%	$ 1,058,623	$ 1,250,746
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 3,579,577			$ 3,579,577	$ -	$ 3,579,577	0%	$ -	$ 3,579,577
10.1	Certain Automobiles	$ 6,918		-3,459	$ 3,459	$ -	$ 3,459	30%	$ 1,038	$ 2,421
10.1	Certain Automobiles	$ 6,918		-3,459	$ 3,459	$ -	$ 3,459	30%	$ 1,038	$ 2,421
3	Buildings - Pre 1988	$ 1,937,630			$ 1,937,630	$ -	$ 1,937,630	5%	$ 96,881	$ 1,840,748
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 569,065,214	$ 44,120,046	-$ 325,188	$ 612,860,072	$ 21,900,888	$ 590,959,184		$ 40,204,222	$ 572,655,849

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.

Schedule 10 CEC - Test Year

Cumulative Eligible Capital					**13,691,783**
Additions					
Cost of Eligible Capital Property Acquired during Test Year		2,000,000			
Other Adjustments		0			
	Subtotal	2,000,000	**x 3/4 =**	1,500,000	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002		0	**x 1/2 =**	0	
				1,500,000	**1,500,000**
Amount transferred on amalgamation or wind-up of subsidiary		0			**0**
	Subtotal				**15,191,783**
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year		0			
Other Adjustments		0			
	Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance					**15,191,783**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")			**15,191,783**	**x 7% =**	**1,063,425**
Cumulative Eligible Capital - Closing Balance					**14,128,358**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	0		0			0	0	
Tax Reserves Not Deducted for accounting purposes								
Reserve for doubtful accounts ss. 20(1)(l)	0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)	0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)	0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)	0		0			0	0	
Other tax reserves	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	0	0	0	0	0	0	0	0
Financial Statement Reserves (not deductible for Tax Purposes)								
General Reserve for Inventory Obsolescence (non-specific)	0		0			0	0	
General reserve for bad debts	280,000		280,000		7,000	273,000	-7,000	
Accrued Employee Future Benefits	5,113,160		5,113,160	440,000		5,553,160	440,000	
- Medical and Life Insurance	0		0			0	0	
-Short & Long-term Disability	0		0			0	0	
-Accmulated Sick Leave	0		0			0	0	
- Termination Cost	0		0			0	0	
- Other Post-Employment Benefits	0		0			0	0	
Provision for Environmental Costs	100,000		100,000	3,000		103,000	3,000	
Restructuring Costs	0		0			0	0	
Accrued Contingent Litigation Costs	0		0			0	0	
Accrued Self-Insurance Costs	0		0			0	0	
Other Contingent Liabilities	0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	0		0			0	0	
Other	0		0			0	0	
	0		0			0	0	
	0		0			0	0	
Total	5,493,160	0	5,493,160	443,000	7,000	5,929,160	436,000	0

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	257,624		257,624
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	257,624	0	257,624
Amount to be used in Test Year			0
Balance available for use post Test Year	257,624	0	257,624

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

Enersource Hydro Mississauga Inc.
Taxable Income - Test Year

		Test Year Taxable Income
Net Income Before Taxes		22,868,885
	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	28,772,771
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	5,929,160
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	90,984
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	

	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		2,933,375
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		400,000
Total Additions		**38,126,270**

Deductions:		
Gain on disposal of assets per financial statements	401	161,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	40,204,222
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,063,425
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	5,493,160
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		2,933,375
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		438,477
Allowance for Funds Used During Construction		273,836
Total Deductions		**50,567,495**
NET INCOME FOR TAX PURPOSES		**10,427,660**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**10,427,660**

Ontario Energy Board

PILS / INCOME TAXES WORK FORM

2013 REBASING YEAR

Enersource Hydro Mississauga Inc.

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 10,427,660	A
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	10.50%	B	$	1,094,904	C = A * B		
Small business credit	Ontario Small Business Threshold	$ 500,000	D					
	Rate reduction	-6.00%	E	-$	30,000	F = D * E		
Ontario Income tax							$ 1,064,904	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate				10.21%	K = J / A		
	Federal tax rate				15.00%	L		
	Combined tax rate						25.21%	M = K + L
Total Income Taxes							$ 2,629,053	N = A * M
Investment Tax Credits							$ 400,000	O
Miscellaneous Tax Credits								P
Total Tax Credits							$ 400,000	Q = O + P
Corporate PILs/Income Tax Provision for Test Year							$ 2,229,053	R = N - Q
Corporate PILs/Income Tax Provision Gross Up [1]					74.79%	S = 1 - M	$ 751,455	T = R / S - N
Income Tax (grossed-up)							$ 2,980,508	U = R + T

Note:
1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Enersource Hydro Mississauga Inc

PILs / Income Taxes Work Form

2014 Test Year

Application Contact Information

Name:	Martin Sultana
Title:	Rates Manager
Phone Number:	905-283-4255
Email Address:	msultana@enersource.com

Enersource Hydro Mississauga Inc
PILs / Income Taxes Work Form
2014 Test Year

Data Input Sheet - Applicant's Rate Base

Rate Base			**$**	**643,384,158**	
Deemed ShortTerm Debt %	4.00%	T	$	25,735,366	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	360,295,128	*X = S * U*
Deemed Equity %	40.00%	V	$	257,353,663	*Y = S * V*
Short Term Interest Rate	2.08%	Z	$	535,296	*AC = W * Z*
Long Term Interest	5.09%	AA	$	18,344,066	*AD = X * AA*
Return on Equity (Regulatory Income)	9.12%	AB	**$**	**23,470,654**	*AE = Y * AB*
Return on Rate Base			**$**	**42,350,016**	*AF = AC + AD + AE*

	2014 Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	Yes
2. Does the applicant have any SRED Expenditures?	Yes
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No
4. Does the applicant have any Capital Leases?	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	Yes
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No

Enersource Hydro Mississauga Inc
PILs / Income Taxes Work Form
2014 Test Year

Tax Rate & Exemptions

Tax Rates **Federal & Provincial** **As of March 22, 2011**	**Effective** **January 1, 2011**	**Effective** **January 1, 2012**	**Effective** **January 1, 2013**	**Effective** **January 1, 2014**	
Federal income tax					
General corporate rate	38.00%	38.00%	38.00%	38.00%	
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	
Rate reduction	-11.50%	-13.00%	-13.00%	-13.00%	
	16.50%	15.00%	15.00%	15.00%	(refer to Note 1)
Ontario income tax	11.75%	11.25%	10.50%	10.00%	
Combined federal and Ontario	28.25%	26.25%	25.50%	25.00%	
Federal & Ontario Small Business					
Federal small business threshold	500,000	500,000	500,000	500,000	
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	
Federal small business rate	11.00%	11.00%	11.00%	11.00%	
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	

NOTES:

1. Federal Budgets of March 22, 2011 and June 6, 2011 reaffirmed the corporate tax rate reductions to 16.5% in 2011 and 15% in 2012.

Enersource Hydro Mississauga Inc
PILs / Income Taxes Work Form
2014 Test Year

Schedule 8 CCA - 2014 Test Year

Class	Class Description	UCC Test Year Opening Balance	Adjustment	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 301,876,683		$ 301,876,683	4,432,251		$ 306,308,934	$ 2,216,126	$ 304,092,809	4%	$ 12,163,712	$ 294,145,222
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 148,966		$ 148,966			$ 148,966	$ -	$ 148,966	6%	$ 8,938	$ 140,028
2	Distribution System - pre 1988	$ 29,162,637		$ 29,162,637			$ 29,162,637	$ -	$ 29,162,637	6%	$ 1,749,758	$ 27,412,879
8	General Office/Stores Equip	$ 5,317,647		$ 5,317,647	1,802,782		$ 7,120,429	$ 901,391	$ 6,219,038	20%	$ 1,243,808	$ 5,876,622
10	Computer Hardware/ Vehicles	$ 4,241,718		$ 4,241,718	1,842,711		$ 6,084,429	$ 921,356	$ 5,163,074	30%	$ 1,548,922	$ 4,535,507
10.1	Certain Automobiles	$ 143,181		$ 143,181			$ 143,181	$ -	$ 143,181	30%	$ 42,954	$ 100,226
12	Computer Software	$ 1,661,415		$ 1,661,415	3,575,752		$ 5,237,167	$ 1,787,876	$ 3,449,291	100%	$ 3,449,291	$ 1,787,876
13 1	Lease # 1	$ -		$ -			$ -	$ -	$ -		$ -	$ -
13 2	Lease #2	$ -		$ -			$ -	$ -	$ -		$ -	$ -
13 3	Lease # 3	$ -		$ -			$ -	$ -	$ -		$ -	$ -
13 4	Lease # 4	$ -		$ -			$ -	$ -	$ -		$ -	$ -
14	Franchise	$ -		$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ -		$ -			$ -	$ -	$ -	8%	$ -	$ -
42	Fibre Optic Cable	$ -		$ -			$ -	$ -	$ -	12%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -		$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -		$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 29,227		$ 29,227			$ 29,227	$ -	$ 29,227	45%	$ 13,152	$ 16,075
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -		$ -			$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 223,398,461		$ 223,398,461	33,150,289		$ 256,548,750	$ 16,575,145	$ 239,973,605	8%	$ 19,197,888	$ 237,350,861
50	Data Network Infrastructure Equipment - post Mar 2007	$ 1,250,746		$ 1,250,746	547,037		$ 1,797,783	$ 273,519	$ 1,524,264	55%	$ 838,345	$ 959,438
52	Computer Hardware and system software	$ -		$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 3,579,577		$ 3,579,577			$ 3,579,577	$ -	$ 3,579,577	0%	$ -	$ 3,579,577
10.1	Certain Automobiles	$ 2,421	-$ 2,421	$ -			$ -	$ -	$ -	30%	$ -	$ -
10.1	Certain Automobiles	$ 2,421	-$ 2,421	$ -			$ -	$ -	$ -	30%	$ -	$ -
3	Buildings - Pre 1988	$ 1,840,748		$ 1,840,748			$ 1,840,748	$ -	$ 1,840,748	5%	$ 92,037	$ 1,748,711
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
		$ -					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 572,655,849	-$ 4,843	$ 572,651,007	$ 45,350,822	$ -	$ 618,001,829	$ 22,675,411	$ 595,326,418		$ 40,348,807	$ 577,653,022

Enersource Hydro Mississauga Inc
PILs / Income Taxes Work Form
2014 Test Year

Taxable Income - 2014 Test Year

		Test Year Taxable Income
Net Income Before Taxes		23,470,654

	T2 S1 line #	
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	30,304,933
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes-joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	0
Reserves from financial statements-balance at end of year	126	5,929,160
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	90,964
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		2,933,375
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		400,000

Total Additions		**39,658,432**
Deductions:		
Gain on disposal of assets per financial statements	401	161,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	40,348,807
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,063,425
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	5,493,160
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		2,933,375
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		438,477
Allowance for Funds Used During Construction		273,836
Total Deductions		**50,712,079**
NET INCOME FOR TAX PURPOSES		**12,417,007**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**12,417,007**

Enersource Hydro Mississauga Inc
PILs / Income Taxes Work Form
2014 Test Year

PILs Tax Provision - 2014 Test Year

Regulatory Taxable Income						$ 12,417,007	**A**
Ontario Income Taxes							
Income tax payable	**Ontario Income Tax**	10.00%	**B**	$1,241,701	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**				
	Rate reduction	-5.50%	**E**	-$ 27,500	**F = D * E**		
Ontario Income tax						$ 1,214,201	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			9.78%	**K = J / A**		
	Federal tax rate			15.00%	**L**		
	Combined tax rate					24.78%	**M = K + L**
Total Income Taxes						**$ 3,076,752**	**N = A * M**
Investment Tax Credits						$ 400,000	**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						**$ 400,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 2,676,752**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]				75.22%	**S = 1 - M**	**$ 881,743**	**T = R / S - N**
Income Tax (grossed-up)						**$ 3,558,494**	**U = R + T**

Note:
1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Charitable Donations and Low-Income Energy Assistance Programs

On March 10, 2009, the Board issued its *Report of the Board: Low-Income Energy Assistance Program* (the "LEAP Report"). The LEAP Report describes policies and measures for the electricity and natural gas distributors to assist low-income energy consumers, including emergency financial assistance. Enersource has adopted the principles, policies and recommendations of the LEAP Report. Enersource's LEAP-related initiatives and charitable donations are described more fully below.

As set out in the LEAP Report, Enersource has determined that 0.12% of the 2013 Test Year distribution revenue is a reasonable amount to provide low-income customers with emergency financial assistance. The LEAP amount has been calculated based on total distribution revenues and will be recovered from all rate classes based on the respective distribution revenue of each of those rate classes.

Enersource's charitable contributions between the period 2008-2013 are included as part of Enersource's OM&A expenses. The only charitable donations included in the 2013 Test Year relate to LEAP. Enersource uses the Dixie Bloor Neighbourhood Drop-In Centre as its designated LEAP agency and provides two separate payments during each year.

Table 1 below provides a summary of the charitable donation and LEAP expenses for 2008 through 2013.

Enersource donated a large bucket truck to Sudbury's Cambrian College in 2008 to assist with Cambrian's Powerline Technician program that was established for

the power distribution industry. All other donations made by Enersource other than to LEAP are immaterial.

Table 1 – Charitable Donations/LEAP

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Winter Warmth/LEAP	40	31	40	50	140	145	155
Cambrian College	-	40	-	-	-	-	-

Green Energy Act Plan Operating Costs

As discussed in the Board's *Filing Requirements for Transmission and Distribution Applications* issued June 22, 2011, in Section 2.3.4, Green Energy Act Requirements, distributors filing cost of service rate applications for 2012 and subsequent rate years must file with the Board a Green Energy Act Plan (GEA Plan) as part of such an application.

Enersource has prepared a basic GEA Plan which is found at Exhibit 2 Tab 2 Schedule 3 Appendix 1. This has been prepared in accordance with the Board's EB-2009-0397 Filing Requirements, dated March 25, 2010

This basic GEA Plan provides information regarding the connection of renewable generation, but Enersource is not proposing preliminary work for the development of a smart grid.

Conservation and demand management ("CDM") programs and costs are not included in the GEA Plan.

The capital expenditures to address renewable generation as per the Green Energy Act are identified in the GEA Plan and are addressed in the discussion at Exhibit 2 Tab 2 Schedule 3.

Enersource is not proposing any additional OM&A costs to fulfil its commitments pursuant to its basic GEA Plan.

Cost of Capital and Capital Structure

Capital Structure

Enersource has relied on the OEB's deemed capital structure of 56% long-term debt, 4% short-term debt and 40% common equity for rate-making purposes in this Application. This is consistent with the structure set out in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* dated December 20, 2006 and the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2009. This approach is also consistent with past and current practices and Enersource is not proposing to make any changes to this capital structure.

Enersource seeks to maintain a debt-to-equity ratio of 60:40 for its actual total debt-to-equity capital structure by maintaining the appropriate level of debt and/or issuing dividends to Enersource Corporation ("EC"). Enersource does not forecast any new long-term debt issuance in the Bridge or Test Years and expects to maintain the actual capital structure close to the deemed capital structure. On April 29, 2011, EC issued private placement debt of $320 million. This replaced previous debt of $290 million of 10-year Borealis-Enersource Bonds that were issued May 1, 2001 at a coupon rate of 6.29 per cent. The prospectus for this debt issuance is provided at Exhibit 1 Tab 3 Schedule 6.

Enersource proposes a 6.58% weighted cost of capital for the 2013 Test Year, based on a cost of debt of 4.89% and a return on equity of 9.12%, as set out in more detail below. The Board's Appendix 2-N, which shows the calculation of the cost of capital from 2008 through 2013, has been completed and is filed as Exhibit 5 Tab 1 Schedule 1 Appendix 2-N.

Total Cost of Debt

Enersource is proposing a total debt cost rate of 4.89% which is comprised of 56% long-term debt at 5.0914% and 4% short-term debt at 2.08%. Details supporting this proposal are explained in more detail below.

Long-Term Debt

On April 29, 2011, EC successfully completed its private placement debt offering of $320 million. The placement is comprised of $110 million of Series A 10-year debentures with a fixed coupon rate of 4.521%, and $210 million of Series B 30-year debentures with a fixed coupon rate of 5.297%. Detail on the repayment schedule for the debt placement is found at Attachment 1 to this exhibit.

The net proceeds of the debentures were used to repay the amount owed by EC to Borealis Infrastructure Trust and the balance will be used for general corporate purposes. The costs to issue these debentures amounted to $2.192 million which are being amortized using the effective interest rate over the life of the bonds. The total cost of long-term debt is 5.0914%, as shown in Attachment 1.

Short-Term Debt

Enersource is requesting a return on short-term debt for the 2013 Test Year of 2.08% in accordance with the *Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012* issued by the Board on November 3, 2011. Enersource understands that the Board will finalize the return on short-term debt for cost of service applications for rates effective January 1, 2013 based on 2012 market interest rate information. Enersource's use of 2.08% is without prejudice to any revised rates that may be adopted by the OEB in November, 2012.

Preference Shares

Enersource currently does not have any preference shares issued nor has it forecast for any issuance for the 2013 Test Year.

Return on Equity

Enersource is requesting a return on equity ("ROE") for the 2013 Test Year of 9.12% in accordance with the *Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012* issued by the Board on March 2, 2012. Enersource understands that the Board will finalize the ROE for cost of service applications for rates effective January 1, 2013 later this year based on market interest rate information. Enersource's use of an ROE of 9.12% is without prejudice to any revised ROE that may be adopted by the OEB in November, 2012.

ATTACHMENT 1

Enersource 2011 Bond Repayment Schedule					
Facts				**Series B 30 Years Due April 29, 2041**	**Series A 10 Years Due April 29, 2021**
Issue Date			4/29/11	66%	34%
Face amount			$320,000,000	$210,000,000	$110,000,000
Issue Costs (Estimated)			$2,195,881	$1,402,941	$792,941
Initial Measurement, net of issue costs			$317,804,119	$208,597,059	$109,207,059
Coupon Rate				5.297%	4.521%
Frequency of coupon	Semi-annually				
Term (Maturity)					
Prepayment option, if so, how this is determined?			**None**		
Is the prepayment option closely related to the debt?			**N/A**		
Approximate annual effective rate using the IRR function					
29-Apr-11				$208,597,059	$109,207,059
29-Apr-12				-$11,123,700	-$4,973,100
29-Apr-13				-$11,123,700	-$4,973,100
29-Apr-14				-$11,123,700	-$4,973,100
29-Apr-15				-$11,123,700	-$4,973,100
29-Apr-16				-$11,123,700	-$4,973,100
29-Apr-17				-$11,123,700	-$4,973,100
29-Apr-18				-$11,123,700	-$4,973,100
29-Apr-19				-$11,123,700	-$4,973,100
29-Apr-20				-$11,123,700	-$4,973,100
29-Apr-21				-$11,123,700	-$114,973,100
29-Apr-22				-$11,123,700	
29-Apr-23				-$11,123,700	
29-Apr-24				-$11,123,700	
29-Apr-25				-$11,123,700	
29-Apr-26				-$11,123,700	
29-Apr-27				-$11,123,700	
29-Apr-28				-$11,123,700	
29-Apr-29				-$11,123,700	
29-Apr-30				-$11,123,700	
29-Apr-31				-$11,123,700	
29-Apr-32				-$11,123,700	
29-Apr-33				-$11,123,700	
29-Apr-34				-$11,123,700	
29-Apr-35				-$11,123,700	
29-Apr-36				-$11,123,700	
29-Apr-37				-$11,123,700	
29-Apr-38				-$11,123,700	
29-Apr-39				-$11,123,700	
29-Apr-40				-$11,123,700	
29-Apr-41				-$221,123,700	
IRR				**5.3422%**	**4.6126%**
			WACC		**5.0914%**

Amortization Schedule – Series B						
Date	**Cash Flow**	**EIR**	**Amortization**	**Def. Costs**	**Principal**	**Net Bond Payable**
	5.2970%	5.3422%				
29-Apr-11				$1,402,941	$210,000,000	$208,597,059
31-Dec-11	7,497,069	7,510,485	(13,416)	$1,389,524	$210,000,000	$208,610,476
31-Dec-12	11,123,700	11,144,323	(20,623)	$1,368,902	$210,000,000	$208,631,098
31-Dec-13	11,123,700	11,145,425	(21,725)	$1,347,177	$210,000,000	$208,652,823
31-Dec-14	11,123,700	11,146,585	(22,885)	$1,324,292	$210,000,000	$208,675,708
31-Dec-15	11,123,700	11,147,808	(24,108)	$1,300,184	$210,000,000	$208,699,816
31-Dec-16	11,123,700	11,149,095	(25,395)	$1,274,789	$210,000,000	$208,725,211
31-Dec-17	11,123,700	11,150,452	(26,752)	$1,248,037	$210,000,000	$208,751,963
31-Dec-18	11,123,700	11,151,881	(28,181)	$1,219,855	$210,000,000	$208,780,145
31-Dec-19	11,123,700	11,153,387	(29,687)	$1,190,169	$210,000,000	$208,809,831
31-Dec-20	11,123,700	11,154,973	(31,273)	$1,158,896	$210,000,000	$208,841,104
31-Dec-21	11,123,700	11,156,643	(32,943)	$1,125,953	$210,000,000	$208,874,047
31-Dec-22	11,123,700	11,158,403	(34,703)	$1,091,249	$210,000,000	$208,908,751
31-Dec-23	11,123,700	11,160,257	(36,557)	$1,054,692	$210,000,000	$208,945,308
31-Dec-24	11,123,700	11,162,210	(38,510)	$1,016,182	$210,000,000	$208,983,818
31-Dec-25	11,123,700	11,164,267	(40,567)	$975,615	$210,000,000	$209,024,385
31-Dec-26	11,123,700	11,166,435	(42,735)	$932,880	$210,000,000	$209,067,120
31-Dec-27	11,123,700	11,168,718	(45,018)	$887,863	$210,000,000	$209,112,137
31-Dec-28	11,123,700	11,171,122	(47,422)	$840,440	$210,000,000	$209,159,560
31-Dec-29	11,123,700	11,173,656	(49,956)	$790,484	$210,000,000	$209,209,516
31-Dec-30	11,123,700	11,176,325	(52,625)	$737,860	$210,000,000	$209,262,140
31-Dec-31	11,123,700	11,179,136	(55,436)	$682,424	$210,000,000	$209,317,576
31-Dec-32	11,123,700	11,182,097	(58,397)	$624,027	$210,000,000	$209,375,973
31-Dec-33	11,123,700	11,185,217	(61,517)	$562,510	$210,000,000	$209,437,490
31-Dec-34	11,123,700	11,188,503	(64,803)	$497,706	$210,000,000	$209,502,294
31-Dec-35	11,123,700	11,191,965	(68,265)	$429,441	$210,000,000	$209,570,559
31-Dec-36	11,123,700	11,195,612	(71,912)	$357,529	$210,000,000	$209,642,471
31-Dec-37	11,123,700	11,199,454	(75,754)	$281,775	$210,000,000	$209,718,225
31-Dec-38	11,123,700	11,203,501	(79,801)	$201,975	$210,000,000	$209,798,025
31-Dec-39	11,123,700	11,207,764	(84,064)	$117,911	$210,000,000	$209,882,089
31-Dec-40	11,123,700	11,212,255	(88,555)	$29,357	$210,000,000	$209,970,643
29-Apr-41	3,626,631	3,657,045	(29,357)	$0	$210,000,000	$210,000,000

Amortization Schedule – Series A						
Date	**Cash Flow**	**EIR**	**Amortization**	**Def. Costs**	**Principal**	**Net Bond Payable**
	4.52%	4.6126%				
29-Apr-11				$792,941	$110,000,000	$109,207,059
31-Dec-11	3,351,733	3,394,996	(43,263)	$749,677	$110,000,000	$109,250,323
31-Dec-12	4,973,100	5,039,287	(66,187)	$683,491	$110,000,000	$109,316,509
31-Dec-13	4,973,100	5,042,340	(69,240)	$614,251	$110,000,000	$109,385,749
31-Dec-14	4,973,100	5,045,534	(72,434)	$541,817	$110,000,000	$109,458,183
31-Dec-15	4,973,100	5,048,875	(75,775)	$466,043	$110,000,000	$109,533,957
31-Dec-16	4,973,100	5,052,370	(79,270)	$386,773	$110,000,000	$109,613,227
31-Dec-17	4,973,100	5,056,026	(82,926)	$303,847	$110,000,000	$109,696,153
31-Dec-18	4,973,100	5,059,851	(86,751)	$217,096	$110,000,000	$109,782,904
31-Dec-19	4,973,100	5,063,853	(90,753)	$126,343	$110,000,000	$109,873,657
31-Dec-20	4,973,100	5,068,039	(94,939)	$31,404	$110,000,000	$109,968,596
29-Apr-21	1,621,367	1,653,747	(31,404)	$0	$110,000,000	$110,000,000

Appendix 2-N

Historical Year - 2008 Approved Test Year

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$278,075	6.44%	$17,908
2	Short-term Debt	4.00% (1)	$19,862	4.47%	$888
3	**Total Debt**	60.0%	$297,937	6.31%	$18,796
	Equity				
4	Common Equity	40.00%	$198,625	8.57%	$17,022
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$198,625	8.57%	$17,022
7	**Total**	100.0%	$496,562	7.21%	$35,818

Historical Year - 2008 Actual

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	60.00%	$294,572	6.44%	$18,970
2	Short-term Debt	0.00% (1)	$ -	4.47%	$ -
3	**Total Debt**	60.0%	$294,572	6.44%	$18,970
	Equity				
4	Common Equity	40.00%	$196,381	8.57%	$16,830
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$196,381	8.57%	$16,830
7	**Total**	100.0%	$490,953	7.29%	$35,800

Historical Year - 2009 Actual

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	59.00%	$302,081	6.44%	$19,454
2	Short-term Debt	0.00% (1)	$ -	4.47%	$ -
3	**Total Debt**	59.0%	$302,081	6.44%	$19,454
	Equity				
4	Common Equity	41.00%	$209,920	8.57%	$17,990
5	Preferred Shares		$ -		$ -
6	**Total Equity**	41.0%	$209,920	8.57%	$17,990
7	**Total**	100.0%	$512,001	7.31%	$37,444

Historical Year - 2010 Actual

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	58.10%	$316,513	6.44%	$20,383
2	Short-term Debt	0.00% (1)	$ -	4.47%	$ -
3	**Total Debt**	58.1%	$316,513	6.44%	$20,383
	Equity				
4	Common Equity	41.90%	$228,259	8.57%	$19,562
5	Preferred Shares		$ -		$ -
6	**Total Equity**	41.9%	$228,259	8.57%	$19,562
7	**Total**	100.0%	$544,772	7.33%	$39,945

Historical Year - 2011 Actual (MIFRS)

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	58.30%	$327,292	5.54%	$18,135
2	Short-term Debt	0.00% (1)	$ -	4.47%	$ -
3	**Total Debt**	58.3%	$327,292	5.54%	$18,135
	Equity				
4	Common Equity	41.70%	$234,101	8.57%	$20,062
5	Preferred Shares		$ -		$ -
6	**Total Equity**	41.7%	$234,101	8.57%	$20,062
7	**Total**	100.0%	$561,393	6.80%	$38,197

Bridge Year - 2012 (MIFRS)

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$332,594	5.09%	$16,934
2	Short-term Debt	4.00% (1)	$23,757	2.08%	$494
3	**Total Debt**	60.0%	$356,351	4.89%	$17,428
	Equity				
4	Common Equity	40.00%	$237,567	9.12%	$21,666
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$237,567	9.12%	$21,666
7	**Total**	100.0%	$593,918	6.58%	$39,094

Test Year - 2013 (MIFRS)

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$351,057	5.09%	$17,874
2	Short-term Debt	4.00% (1)	$25,076	2.08%	$522
3	**Total Debt**	60.0%	$376,133	4.89%	$18,395
	Equity				
4	Common Equity	40.00%	$250,755	9.12%	$22,869
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$250,755	9.12%	$22,869
7	**Total**	100.0%	$626,888	6.58%	$41,264

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Calculation of Revenue Deficiency or Sufficiency

This evidence provides a summary of the revenue required by Enersource in 2013 and 2014 to continue to distribute electricity in a safe and reliable manner. Enersource's total revenue requirement is offset by revenues generated from sources other than distribution rates. The following calculation of the revenue deficiency/sufficiency excludes the recovery/refund of regulatory assets and liabilities from the revenue requirement, as regulatory deferral and variance accounts are disposed through separate rate riders, as identified in Exhibit 9.

The revenue deficiency/sufficiency for 2013 was calculated using the following inputs:

- Approved 2012 rates and 2012 Smart Meter Funding Adder[1], but not including:
    - rate riders for the disposition of deferral and variance accounts;
    - the 50% Tax Sharing volumetric rate; and
    - the rate rider to recover Lost Revenue Adjustment Mechanism;
- 2013 forecast of customers and load forecast, as provided in Exhibit 3; and

[1] At the time of filing the Application, the final rate order for Enersource's 2012 rates had not yet been approved. The Application has been produced assuming that Enersource's 2012 rates would be approved as proposed.

- the 2013 base revenue requirement calculated as shown in Table 1 below and further detailed in the Revenue Requirement Work Form in Exhibit 1 Tab 2 Schedule 1 Appendix 2-C(i).

The revenue deficiency/sufficiency for 2014 was calculated using 2013 proposed rates, excluding all rate riders/adders, 2013 forecast of customers and load forecast and 2014 base revenue requirement. The Revenue Requirement Work Form relating to 2014 is provided in Exhibit 1 Tab 2 Schedule 1 Appendix 2-C (ii).

Table 1: Revenue Sufficiency/Deficiency ($000s)

	2013	2014
Return on Rate Base	41,264	42,350
Distribution Expenses (excluding amortization)	61,099	61,099
Amortization	28,773	30,305
Payment in Lieu of Taxes	2,981	3,559
Service Revenue Requirement	134,117	137,313
Less: Revenue Offsets	(4,830)	(4,830)
Base Revenue Requirment	129,287	132,483
Transformer Allowance	1,998	1,998
Total Revenue to Recover in Rates	131,285	134,481
2013 Load at 2012 Rates	116,543	-
2013 Load at 2013 Rates	-	131,285
Revenue Deficiency	(14,742)	(3,196)

Table 2 below summarizes the drivers of the identified revenue deficiency in 2013.

Table 2: Drivers of Revenue Deficiency in 2013 ($000s)

Driver		Impact on 2013 Revenue Requirement	Reference
Increase in OM&A (excluding amortization):			
Salaries	4,065		
Benefits	3,928		
IFRS Transition - Overhead Burdens	2,774		
Bad Debt Expense	1,975		
New Building	1,668		
Distribution System Maintenance & Repairs	1,350		
Asset Management Plan	1,153		
Other (net of Price Cap Index increases via IRM)	2,626		
Subtotal		19,539	Exhibit 4
Decrease in Amortization		(6,166)	Exhibit 4
2012 Smart Meter Funding Adder		(1,839)	Exhibit 9
Increase in Return on Rate Base		4,573	Exhibit 6
Decrease in PILs		(4,791)	Exhibit 4
Load / Customers Impact		2,785	Exhibit 3
Decrease in Revenue Offsets		641	Exhibit 3
Total Deficiency		14,742	

Table 3 below identifies the difference between the 2012 Smart Meter Funding Adder of $1,839, equal to $0.77 per metered customer per month, which is proposed to be collected for a 12-month period, versus the 2013 smart meter

revenue requirement of $5,164[2]. The 2012 Smart Meter Funding Adder represents a true-up between the cumulative funding adders versus the cumulative smart meter revenue requirement. It is important to note that the exclusion of this difference from Table 2 above would result in a reduction to the 2013 revenue deficiency to $11,417 (Table 4).

Table 3: Revenue Deficiency related to Smart Meters ($000s)

2013 - Smart Meter Revenue Requirement	5,164
2012 Smart Meter Funding Adder	(1,839)
Revenue Deficiency included in Table 2	3,325

Table 4: Revenue Deficiency Excluding Smart Meters ($000s)

2013 Revenue Deficiency	(Table 2)	14,742
Less: Revenue Deficiency related to Smart Meters	(Table 3)	(3,325)
2013 Revenue Deficiency excluding Smart Meters		11,417

The change in the 2013 revenue requirement is primarily due to the:

- inclusion of smart meter operating and capital costs in revenue requirement, increase in employee benefit costs due to an increase in pension contribution rates since 2008, and the transition to IFRS and its impact on the inability to

[2] Refer to Smart Meter Revenue Requirement model at Exhibit 9 Tab 2 Schedule 1 Appendix 1.

capitalize indirect overhead costs and the impact of the derecognition of assets;

- decrease in amortization as a result of the change in useful lives, partially offset by an increase in amortization due to additions to rate base in 2009 through to 2013;

- increase in return on equity attributable to the continued investment in the distribution system resulting in an increase in the year-end net book value of assets of approximately $109 from 2008 (Board-approved) to 2013. This includes investments based on the Asset Management Plan and the installation of smart meters. These increases are partially offset by the decrease in the cost of capital from 7.213% to 6.582%;

- decrease in Payment in Lieu of Taxes mainly as a result of decreases in corporate income tax rates, elimination of capital tax, and the differences between tax and book treatment of certain costs;

- impact of load forecast and number of customers as detailed in Exhibit 3; and

- decrease in revenue offsets.

Table 5 below identifies the drivers of the revenue deficiency in 2014.

Table 5: Drivers of Revenue Deficiency in 2014 ($000s)

Driver	Impact on 2014 Revenue Requirement	Reference
Increase in OM&A (excluding amortization)	-	
Increase in Amortization	1,532	Exhibit 4
Increase in Return on Rate Base	1,086	Exhibit 6
Increase in PILs	578	Exhibit 4
Load / Customers Impact	-	
Decrease in Revenue Offsets	-	
Total Deficiency	3,196	

The increase in the 2014 revenue requirement is mainly due to the:

- increase in amortization and return on equity due to additions to rate base in 2014; and
- increase in Payment in Lieu of Taxes due to the increase in deemed net income resulting from the higher rate base and the increase in amortization expense, partially offset by the increase in the capital cost allowance deduction and a decrease in the corporate income tax rate.

Cost Allocation Study Overview

This exhibit provides the cost allocation methods and results for the 2013 Test Year. The evidence describes the cost allocation study and results, proposed adjustments to cost allocation, and revenue-to-cost ratios.

Introduction and Background of Enersource's Cost Allocation

Enersource completed its initial cost allocation study ("Cost Study") following the Board's prescribed methodology as set out in the Board's *Directions on Cost Allocation Methodology for Electricity Distributors (EB-2005-0317),* issued on September 29, 2006. This Cost Study was used as the basis for the rate design proposed in Enersource's 2008 Electricity Distribution Rate Application (EB-2007-0706). The approved Settlement Agreement for EB-2007-0706[1] stated the following with respect to cost allocation:

> Subject to AMPCO's proviso as set forth below, the parties agree that the Revenue to Cost ratios determined through the Cost Allocation Review - Informational Filing will be revised as set out in the table below: all customer classes that had revenue to cost ratios below 100% will be increased to 91.5%, and all customer classes that had revenue to cost ratios above 100% will be reduced to 111%. This change is based on the findings of the Cost Allocation Review — Informational Filing, supports movement towards the revenue to cost ratios endorsed by the Board in its recently issued *Report on Cost Allocation for Electricity Distributors,*

[1] EB-2007-0706 Settlement Agreement dated December 21, 2007, page 32.

dated November 28, 2007 (the "*Cost Allocation Report*") and avoids material or adverse rate impacts. Further, the costs related to recovery of the transformer ownership allowance will be reallocated to the customer class receiving this allowance.

	Revenue To Cost Ratio CAR-IF(%) RUN 1	Revised Revenue to Cost Ratio 2008 Test Year (%)
Residential	87.69	91.50
GS<50 kW	113.60	111.00
Small Commercial	149.92	111.00
GS>50 kW	120.64	111.00
GS>500 kW	86.78	91.50
Large User	137.16	111.00
Street Lighting	25.22	91.50

The parties agree that the rates and bill impacts set forth in Appendix C annexed hereto are consistent with the implementation of these revised revenue to cost ratios and the agreed to reallocation of the transformer allowance.

After the completion of the evidentiary record in this proceeding, the Board issued the Cost Allocation Report that states that "To the extent that distributors can address influencing factors that are within their control (such as data quality), they should attempt to do so and to move revenue-to-cost ratios nearer to one." (p. 4) All parties, except AMPCO, believe that the revenue to cost ratios settled in this Agreement are consistent with the Cost Allocation Report.

Because at this point in these proceedings AMPCO is not in a position to review Enersource's treatment of influencing factors

> within its control (such as data quality) to determine whether the proposed revenue-to-cost ratios for 2008 are appropriate, AMPCO cannot determine whether the settlement is in compliance with the Cost Allocation Report.
>
> The Cost Allocation Report states that, where it is determined that implementing the policies of the Cost Allocation Report is "impractical in any given case and can be reasonably deferred, the cost allocation issue may be addressed in the context of the distributor's 2009 IRM rate application." (at p.14). AMPCO has accepted the proposed 2008 revenue-to-cost ratios on the understanding that it may address in Enersource's 2009 IRM rate application the appropriateness of continuing those revenue to cost ratios for years after the 2008 Test Year. All parties agree that AMPCO should be free to do so, and that all parties will be free to take such positions on revenue to cost ratios as they consider appropriate at that time, without regard to the terms of this Agreement.

The *Report of the Board on the Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219), issued March 31, 2011, ("Cost Allocation Review") set out a number of revisions to the Board's electricity distribution cost allocation policies that are to be implemented through cost of service rate applications starting with the 2012 rate year.

On August 5, 2011 the Board issued its revised cost allocation model ("Revised Cost Allocation Model") to be used by distributors filing a cost of service

application for 2012 distribution rates. The Board also released the staff report[2] that documents the changes resulting from the Cost Allocation Review as well as instructions for the Revised Cost Allocation Model.

Enersource has relied on the Cost Allocation Review and Revised Cost Allocation Model to complete this 2013 cost allocation submission. For the purposes of this Application, Enersource has updated the Cost Study (now "2013 Cost Study") to reflect 2013 Test Year costs, annual loads, customer numbers, and hourly load profile demand values. The 2013 demand values were updated by Hydro One Networks Inc. ("Hydro One") for all customer classes.

During the course of the EB-2007-0706 proceeding, the cost allocation model was modified by removing the transformer ownership allowance, a change that has now been incorporated into the *Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements")[3].

Enersource's 2013 Cost Study

This section of the evidence will describe the weighting factors, model runs, load and customer information, and cost information used in Enersource's 2013 Cost Study.

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[2] EB 2010-0219 *Staff Report to the Board – Implementation of Revisions to the Board's Electricity Distribution Cost Allocation Policy*, August 4, 2011.

[3] *Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, June 22, 2011, p.38.

Weighting Factors

Weighting factors are used in the Revised Cost Allocation Model to better reflect cost causality when allocating costs to rate classes. Enersource has made no changes to the weighting factors used in prior cost studies and notes that these weighting factors are consistent with the default weighting factors for services and billings established in the "*Staff Report to the Board – Implementation of the Revisions to the Board's Electricity Distributor Cost Allocation Policy*, Aug 4, 2011"[4]. Enersource has no information that would lead it to depart from the previously-used weighting factors.

Model Runs Included in the 2013 Cost Study

Section 2.10.3 of the Filing Requirements[5] specifies that three sets of cost ratios for each customer class must be provided based on:

- Previously-approved ratios most recently implemented;
- Ratios that would result from the most recently-approved distribution rates and the distributor's forecast of billing quantities in the Test Year, prorated upwards or downwards (as applicable) to match the revenue requirement, together with the updated cost allocation model; and
- Ratios that are proposed for the Test Year, which are the result of the proposed rates with the forecast of billing quantities, together with the updated cost allocation model.

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[4] EB 2010-0219 *Staff Report to the Board – Implementation of Revisions to the Board's Electricity Distribution Cost Allocation Policy*, August 4, 2011, pages 6 to 10.

[5] *Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, June 22, 2011, p. 40.

As previously stated, Enersource completed its initial Cost Study (EB-2005-0317) which was used as the basis for the rate design proposed in Enersource's 2008 Electricity Distribution Rate Application (EB-2007-0706). In this Application consistent with the Filing Guidelines, Enersource has completed the prospective 2013 Cost Study. A rolled up cost allocation model ("Enersource Rolled Up Cost Allocation Model") is provided at Exhibit 7 Tab 1 Schedule 1 Appendix 1. The previously approved, current, and proposed revenue to cost ratios outlined above can be found in Exhibit 7 Tab 1 Schedule 1 Appendix 2-O.

Load and Customer Information

Enersource's 2013 Cost Study has been prepared using the following load and load profile information:

- Annual Loads (kW and kWh, as appropriate) and customer counts: the 2013 forecast of energy load and customer counts by rate class are used for the 2013 Cost Study.

- Hourly Load Profile: new hourly load profiles by rate class have been provided by Hydro One and incorporated into the 2013 Cost Study.

Cost Information

Consistent with the Filing Guidelines, the prospective 2013 Test Year cost information, including all capital and operating costs, are relied upon in the 2013 Cost Study. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data, and load data by primary, line transformer, and secondary categories were developed from the best data available to Enersource, from its engineering records, and its customer and financial systems.

The financial information for the Test Year has been prepared and mapped to the USoA level consistent with the level of detail embedded in the Revised Cost Allocation Model. Information required by the Revised Cost Allocation Model that was not explicitly forecasted for the Test Year was estimated based on scaling factors based on the prior year's ratios. For example, Enersource doesn't maintain separate general ledger accounts to segregate Services Costs (1855). To summarize the forecast into defined functionalized costs in the Revised Cost Allocation Model for Services Costs, the cost of assets, capital contributions, depreciation, and accumulated depreciation have been allocated from the general ledger accounts to which they have been posted based on the best engineering estimates available at the time of the completion of the 2013 Cost Study.

Actual costs per currently installed meters were used to update the Meter Capital work sheet on the Revised Cost Allocation Model. The descriptions were changed on the Meter Capital work sheet to reflect the appropriate Enersource descriptions for the meters currently installed.

Proposed Cost Allocation Adjustments

As outlined in the Cost Allocation Review[6]:

> The Board therefore expects each distributor to include as part of their cost of service application a separate USL rate class in their CA Model and on their proposed Tariff of Rates and Charges.

[6] EB-2010-0219 Report of the Board, Section 2.5.4 page 24.

Enersource currently does not have a separate Unmetered Scattered Load ("USL") rate class. USL customers are currently included within the Small Commercial rate class. A new USL rate class has been included in the Revised Cost Allocation Model and proposed Tariff of Rates and Charges for the 2013 Test Year.

The removal of the USL customers from the Small Commercial rate class left few remaining customers within the Small Commercial class. Enersource proposes merging the Small Commercial rate class (excluding USL customers) with the General Service less than 50 kW ("GS<50 kW") rate class as these remaining Small Commercial customers are similar to GS<50 kW customers and have the same quantity threshold. Further, they are not sufficiently different to GS<50 kW customers in service setup, billing, collections, or meter reading profiles to require a separate rate class.

The Board's cost allocation worksheet, Exhibit 7 Tab 1 Schedule 1 Appendix 2-O, has been updated to reflect the introduction of a new separate USL rate class and the proposed merging of Small Commercial with GS<50 kW as required by section 2.10.10 of the Filing Requirements.

Summary of Revenue-to-Cost Ratios

Table 1 below provides the revenue-to-cost ratios as per the EB-2007-0706 Settlement Agreement. Table 1 also shows the target ranges from the Cost Allocation Review for each of Enersource's current customer classes.

Table 1: 2008 Approved Revenue-to-Cost Ratios

Customer Class	Revenue-to-Cost Ratio Per 2008 Settlement	Revenue-to-Cost Ratio Target Range Per Cost Allocation Review
Residential	91.5%	85% - 115%
Small Commercial Less Than 50 kW	111.0%	80% - 120%
General Service Less Than 50 kW	111.0%	80% - 120%
General Service 50 Kw - 499 kW	111.0%	80% - 180%
General Service 500 Kw - 4999 kW	91.5%	80% - 180%
General Service Large Use (> 5000 kW)	111.0%	85% - 115%
Street Lighting	91.5%	70% - 120%
Unmetered	111.0%	80% - 120%

The revenue-to-cost ratios shown in Table 1 have remained unchanged since 2008.

As discussed above, the data used by Enersource in its 2013 Cost Study is consistent with the cost data that supports the proposed 2013 Test Year revenue requirement.

The rate class customer data used in the 2013 Cost Study is consistent with the 2013 customer forecasts discussed in Exhibit 3 Tab 1 Schedule 2.

The resulting revenue-to-cost ratios from the 2013 Cost Study are shown in Table 2 below. The revenue-to-cost ratio ranges from the Cost Allocation Review are also shown in Table 2.

Table 2: 2013 Initial Revenue-to-Cost Ratios

Customer Class	Revenue-to-Cost Ratio 2013 Test Year	Revenue-to-Cost Ratio Target Range Per Cost Allocation Review
Residential	87%	85% - 115%
General Service Less Than 50 kW	112%	80% - 120%
General Service 50 kW - 499 kW	111%	80% - 120%
General Service 500 kW - 4999 kW	106%	80% - 120%
General Service Large Use (> 5000 kW)	122%	85% - 115%
Street Lighting	95%	70% - 120%
Unmetered Scattered Load	144%	80% - 120%

As illustrated in Table 2, the results from Enersource's initial application of the 2013 Cost Study had two classes, the General Service Large Use (>5000 kW) and the USL class, outside the Board's required ranges. It was therefore necessary to reallocate revenues among rate classes. Enersource proposes to re-balance all classes to within 10% of unity.

The revised revenue-to-cost ratios after the above re-balance are shown in Table 3 below:

Table 3: Proposed 2013 Revenue-to-Cost Ratios

Customer Class	Revenue-to-Cost Ratio 2013 Test Year at Existing Rates	Revenue-to-Cost Ratio 2013 Test Year at Proposed Rates
Residential	87%	90%
General Service Less Than 50 kW	112%	110%
General Service 50 kW - 499 kW	111%	110%
General Service 500 kW - 4999 kW	106%	106%
General Service Large Use (> 5000 kW)	122%	110%
Street Lighting	95%	95%
Unmetered Scattered Load	144%	110%

Enersource is not proposing to re-balance revenue-to-cost ratios after the 2013 Test Year as all revenue-to-cost ratios are well within the Board's target ranges.

Fixed Monthly Service Charges

Table 4 below shows the Fixed Monthly Service Charges which Enersource is proposing for the 2013 Test Year.

Table 4: Proposed 2013 Monthly Service Charges ($)

Customer Class	Proposed Monthly Service Charge
Residential	14.70
General Service Less Than 50 kW	44.68
General Service 50 kW - 499 kW	78.48
General Service 500 kW - 4999 kW	1,639.27
General Service Large Use (> 5000 kW)	12,628.34
Street Lighting	1.52
Unmetered Scattered Load	9.16

For the Residential, General Service Less Than 50 kW, General Service 50 kW – 499 kW, and Street Lighting classes, Enersource's proposed rate is within the minimum and maximum calculated in the "O2 Fixed Charge Floor Ceiling" tab of the 2013 Cost Study. For the General Service 500 kW - 4999 kW, General Service Large Use (> 5000 kW) and Unmetered Scattered Load classes the proposed rates are above the upper bound calculated in the 2013 Cost Study. Section 4.2.2 of the Cost Allocation Report stated that distributors that have monthly service charges that are above the upper bound are not required to make changes to their monthly service charges to bring it to, or below, this level at this time. This provision was not amended in the Cost Allocation Review. As a result, Enersource is not proposing any changes to the monthly service charges as adjusted for the revised 2013 Test Year revenue-to-cost ratios that fall above the maximum in order to bring them to, or below, the maximum level calculated in the 2013 Cost Study.

Ontario Energy Board

2013 COST ALLOCATION

Sheet I1 Utility Information Sheet

Name of LDC:	Enersource Hydro Mississauga
License Number:	ED-2003-0017
Application EB Number:	EB-2012-0033
Date of Submission:	Friday, April 27, 2012
Version:	2.0
Contact Information	
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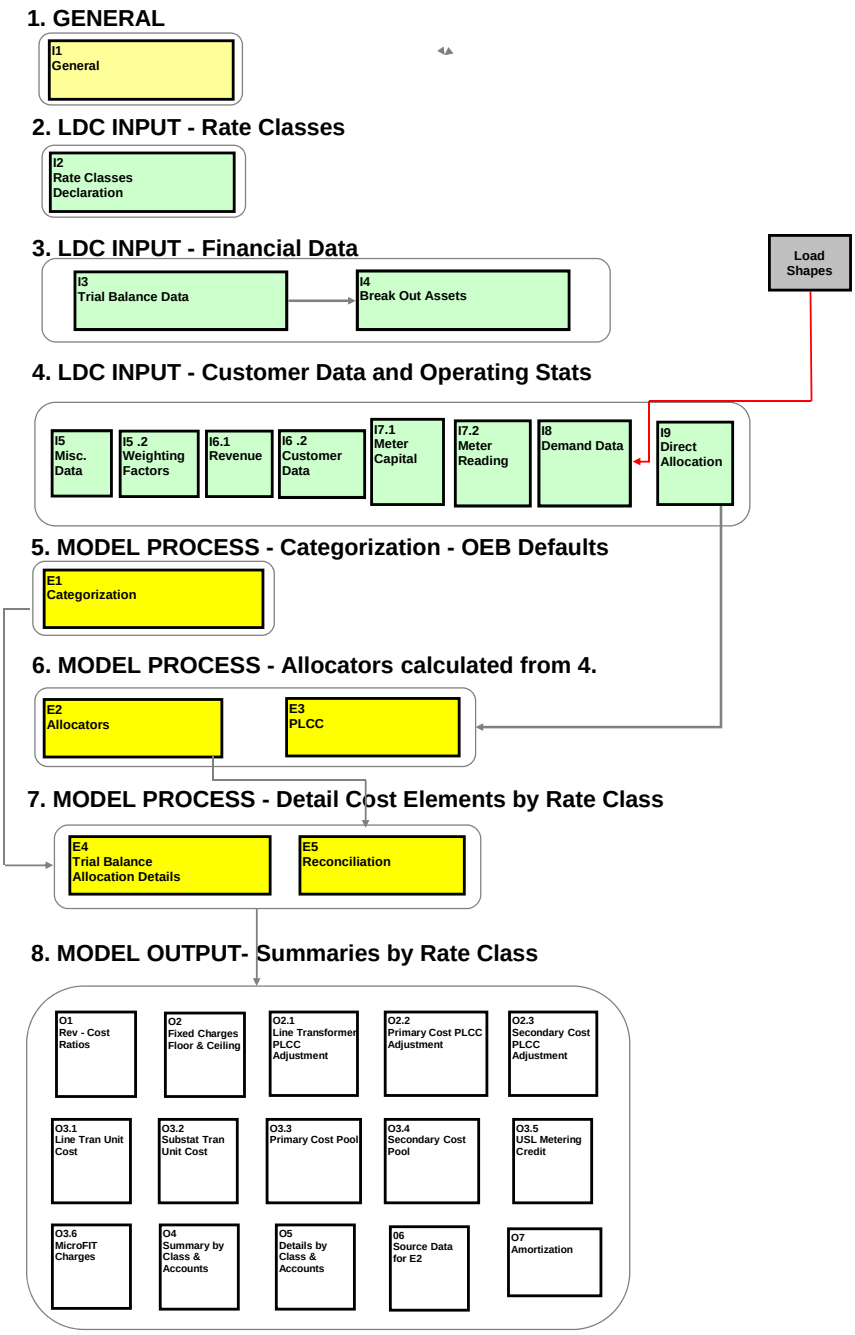
Please Note: Colour Coding Legend

Input Cells	
Output Cells	
Exhibition	
Brought Forward	Brought Forward
Calculation	Calculation
Diagnostic	

Brief Description of Each Worksheet's Function

INPUTS	I1	Intro	Brief explanation of what the pages do.
	I2	LDC data and Classes	Enter LDC specific information and number of classes etc
	I3	TB Data	Forecast Trial Balance
	I4	BO ASSETS	Break out assets into detail functions - bulk deliver, primary and secondary
	I5.1	Misc Data	Input for miscellaneous data where necessary - TBD
	I5.2	Weighting Factors	Invput for weighting factors to be applied to billing and services
	I6.1	Revenue	Input rates and volumes for working up revenue
	I6.2	Customer Data	Input customer related data for generating customer allocators
	I7.1	Meter Capital	Input meter related data for calculating capital costs weighing factors
	I7.2	Meter Reading	Input meter related data for calculating meter reading weighing factors
	I8	Demand Data	Input demand allocators using load data and making LDC specific adjustments
	I9	Direct Allocation	
OUTPUTS	O1	Revenue to cost	Output showing revenue to cost ratios, inter class subsidy etc.
	O2	Fixed Charge	Output showing the range for the Basic Customer charge - TBD
	O2.1	Line Transformer PLCC Adjustment	
	O2.2	Primary Cost PLCC Adjustment	
	O2.3	Secondary Cost PLCC Adjustment	
	O3.1	Line Tran Unit Cost	
	O3.2	Substat Tran Unit Cost	
	O3.3	Primary Cost Pool	
	O3.4	Secondary Cost Pool	
	O3.5	USL Metering Credit	
	O3.6	MicroFIT Charges	
	O4	Summary by Class	Output showing summary of all allocation by class and by US of A
	O5	Detail by Class	Output showing details of individual allocation by class and by USofA
	O6	Source Data for E2	
	O7	Amortization	
EXHIBITS	E1	Categorization	Exhibit showing how costs are categorized
	E2	Allocation Factors	Exhibit summarizing all allocation factors created in I5 to I8 and present the findings in percentages
	E3	PLCC	Backup documentation for calculating Peak Load Carrying Capability.
	E4	Trial Balance Index	Exhibit showing 1. how accounts are grouped for reporting, how accounts are categorized and how accounts are allocated
	E5	Reconciliation	Exhibit showing reconciliation of accounts included and excluded from the allocation study to TB balance


1. GENERAL
I1 General
2. LDC INPUT - Rate Classes
I2 Rate Classes Declaration
3. LDC INPUT - Financial Data
I3 Trial Balance Data
I4 Break Out Assets
Load Shapes
4. LDC INPUT - Customer Data and Operating Stats
I5 Misc. Data
I5 .2 Weighting Factors
I6.1 Revenue
I6 .2 Customer Data
I7.1 Meter Capital
I7.2 Meter Reading
I8 Demand Data
I9 Direct Allocation
5. MODEL PROCESS - Categorization - OEB Defaults
E1 Categorization
6. MODEL PROCESS - Allocators calculated from 4.
E2 Allocators
E3 PLCC
7. MODEL PROCESS - Detail Cost Elements by Rate Class
E4 Trial Balance Allocation Details
E5 Reconciliation
8. MODEL OUTPUT- Summaries by Rate Class
O1 Rev - Cost Ratios
O2 Fixed Charges Floor & Ceiling
O2.1 Line Transformer PLCC Adjustment
O2.2 Primary Cost PLCC Adjustment
O2.3 Secondary Cost PLCC Adjustment
O3.1 Line Tran Unit Cost
O3.2 Substat Tran Unit Cost
O3.3 Primary Cost Pool
O3.4 Secondary Cost Pool
O3.5 USL Metering Credit
O3.6 MicroFIT Charges
O4 Summary by Class & Accounts
O5 Details by Class & Accounts
06 Source Data for E2
O7 Amortization

Ontario

2013 COST ALLOCATION

Enersource Hydro Mississauga

EB-2012-0033

Friday, April 27, 2012

Sheet I2 Class Selection - Run 2

Instructions:
Step 1: Please input your existing classes
Step 2: If this is your first run, select "First Run" in the drop-down menu below
Step 3: After all classes have been entered, Click the "Update" button in row E41

	Run 2		
		Utility's Class Definition	Current
1	Residential	Residential	YES
2	GS <50	GS < 50kW	YES
3	GS>50-Regular		NO
4	GS> 50-TOU	GS 50 - 499kW	YES
5	GS >50-Intermediate	GS 500 - 4999kW	YES
6	Large Use >5MW	Large User > 5MW	YES
7	Street Light	Street Light	YES
8	Sentinel		NO
9	Unmetered Scattered Load	Unmetered	YES
10	Embedded Distributor		NO
11	Back-up/Standby Power		NO
12	Rate Class 1		NO
13	Rate class 2		NO
14	Rate class 3		NO
15	Rate class 4		NO
16	Rate class 5		NO
17	Rate class 6		NO
18	Rate class 7		NO
19	Rate class 8		NO
20	Rate class 9		NO

Update

** **Space available for additional information about this run**

2013 COST ALLOCATION

Enersource Hydro Mississauga

EB-2012-0033

Friday, April 27, 2012

Sheet I3 Trial Balance Data - Run 2

Instructions:

Step 1: Copy Test Year Trial Balance values to Column D21 of this worksheet.

Step 2: Enter the amounts needed to be reclassified to column F.

Step 3: Enter Target Net Income

Step 4: Enter PILs

Step 5: Enter Interest Expense

Step 6: Enter Revenue Requirement

Step 7: Enter Total Rate Base

Step 8: Enter Directly Allocated amounts into column G.

Target Net Income ($)	$22,868,885		
PILs ($)	$2,981,000		
Interest Expense ($)	$18,395,000		
Revenue Requirement ($)	$134,116,889	**From this Sheet**	**Differences?**
Revenue Requirement to be Used in this model ($)	$134,116,889	**$134,116,893**	**Rev Req Matches**
Rate Base ($)	$626,888,458		
Rate Base to be Used in this model ($)	$626,888,458	**$626,888,457**	**Rate Base Matches**

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1005	Cash	$17,330,110				$17,330,110
1010	Cash Advances and Working Funds	$0				$0
1020	Interest Special Deposits	$0				$0
1030	Dividend Special Deposits	$0				$0
1040	Other Special Deposits					$0
1060	Term Deposits					$0
1070	Current Investments					$0
1100	Customer Accounts Receivable					$57,047,000
1102	Accounts Receivable - Services					$0
1104	Accounts Receivable - Recoverable Work					$0
1105	Accounts Receivable - Merchandise, Jobbing, etc.					$0
1110	Other Accounts Receivable					$0
1120	Accrued Utility Revenues					$70,568,000
1130	Accumulated Provision for Uncollectible Accounts--Credit					$0
1140	Interest and Dividends Receivable					$0
1150	Rents Receivable					$0
1170	Notes Receivable					$0
1180	Prepayments					$1,316,500
1190	Miscellaneous Current and Accrued Assets					$0
1200	Accounts Receivable from Associated Companies					$0
1210	Notes Receivable from Associated Companies					$0

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1305	Fuel Stock						$0
1330	Plant Materials and Operating Supplies						$5,850,000
1340	Merchandise						$0
1350	Other Materials and Supplies						$0
1405	Long Term Investments in Non-Associated Companies						$0
1408	Long Term Receivable - Street Lighting Transfer						$0
1410	Other Special or Collateral Funds						$21,500,000
1415	Sinking Funds						$0
1425	Unamortized Debt Expense						$2,006,910
1445	Unamortized Discount on Long-Term Debt--Debit						$0
1455	Unamortized Deferred Foreign Currency Translation Gains and Losses						$0
1460	Other Non-Current Assets						$0
1465	O.M.E.R.S. Past Service Costs						$0
1470	Past Service Costs - Employee Future Benefits						$0
1475	Past Service Costs - Other Pension Plans						$0
1480	Portfolio Investments - Associated Companies						$0
1485	Investment in Associated Companies - Significant Influence						$0
1490	Investment in Subsidiary Companies						$0
1505	Unrecovered Plant and Regulatory Study Costs						$0
1508	Other Regulatory Assets						$2,958,059
1510	Preliminary Survey and Investigation Charges						$0
1515	Emission Allowance Inventory						$0
1516	Emission Allowances Withheld						$0
1518	RCVARetail						$0
1520	Power Purchase Variance Account						$0
1525	Miscellaneous Deferred Debits						$0
1530	Deferred Losses from Disposition of Utility Plant						$0
1540	Unamortized Loss on Reacquired Debt						$0
1545	Development Charge Deposits/ Receivables						$0
1548	RCVASTR						$0
1560	Deferred Development Costs						$0
1562	Deferred Payments in Lieu of Taxes						$0
1563	Account 1563 - Deferred PILs Contra Account						$0
1565	Conservation and Demand Management Expenditures and Recoveries						$0
1570	Qualifying Transition Costs						$0
1571	Pre-market Opening Energy Variance						$0
1572	Extraordinary Event Costs						$0
1574	Deferred Rate Impact Amounts						$0
1580	RSVAWMS						$0
1582	RSVAONE-TIME						$0
1584	RSVANW						$0
1586	RSVACN						$0
1588	RSVAPOWER						($17,032,704)
1590	Recovery of Regulatory Asset Balances						$0
1605	Electric Plant in Service - Control Account						$0
1606	Organization						$0
1608	Franchises and Consents						$0
1610	Miscellaneous Intangible Plant						$188
1615	Land						$0
1616	Land Rights						$0
1620	Buildings and Fixtures						$0
1630	Leasehold Improvements						$0
1635	Boiler Plant Equipment						$0
1640	Engines and Engine-Driven Generators						$0
1645	Turbogenerator Units						$0
1650	Reservoirs, Dams and Waterways						$0
1655	Water Wheels, Turbines and Generators						$0
1660	Roads, Railroads and Bridges						$0
1665	Fuel Holders, Producers and Accessories						$0
1670	Prime Movers						$0
1675	Generators						$0
1680	Accessory Electric Equipment						$0
1685	Miscellaneous Power Plant Equipment						$0

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
1705	Land						$0
1706	Land Rights						$0
1708	Buildings and Fixtures						$0
1710	Leasehold Improvements						$0
1715	Station Equipment						$0
1720	Towers and Fixtures						$0
1725	Poles and Fixtures						$0
1730	Overhead Conductors and Devices						$0
1735	Underground Conduit						$0
1740	Underground Conductors and Devices						$0
1745	Roads and Trails						$0
1805	Land						$0
1806	Land Rights						$0
1808	Buildings and Fixtures						$35,768,173
1810	Leasehold Improvements						$0
1815	Transformer Station Equipment - Normally Primary above 50 kV						$0
1820	Distribution Station Equipment - Normally Primary below 50 kV						$65,285,285
1825	Storage Battery Equipment						$0
1830	Poles, Towers and Fixtures				($4,538,325)		$90,766,499
1835	Overhead Conductors and Devices				($802,497)		$16,049,944
1840	Underground Conduit				($1,835,537)		$36,710,743
1845	Underground Conductors and Devices				($7,981,578)		$159,631,558
1850	Line Transformers						$57,276,606
1855	Services				$15,157,937		$15,157,937
1860	Meters						$38,015,782
1555	IFRS Placeholder Asset Account						$0
1865	Other Installations on Customer's Premises						$0
1870	Leased Property on Customer Premises						$0
1875	Street Lighting and Signal Systems						$0
1905	Land						$10,401,532
1906	Land Rights						$0
1908	Buildings and Fixtures						$0
1910	Leasehold Improvements						$0
1915	Office Furniture and Equipment						$5,260,385
1920	Computer Equipment - Hardware						$6,065,439
1925	Computer Software						$25,743,790
1930	Transportation Equipment						$9,541,776
1935	Stores Equipment						$0
1940	Tools, Shop and Garage Equipment						$1,463,130
1945	Measurement and Testing Equipment						$0
1950	Power Operated Equipment						$0
1955	Communication Equipment						$0
1960	Miscellaneous Equipment						$0
1965	Water Heater Rental Units						$0
1970	Load Management Controls - Customer Premises						$0
1975	Load Management Controls - Utility Premises						$0
1980	System Supervisory Equipment						$13,856,478
1985	Sentinel Lighting Rental Units						$0
1990	Other Tangible Property						$0
1995	Contributions and Grants - Credit						($8,726,459)
2005	Property Under Capital Leases						$0
2010	Electric Plant Purchased or Sold						$0
2020	Experimental Electric Plant Unclassified						$0
2030	Electric Plant and Equipment Leased to Others						$0
2040	Electric Plant Held for Future Use						$0
2050	Completed Construction Not Classified--Electric						$0
2055	Construction Work in Progress--Electric						$4,663,989
2060	Electric Plant Acquisition Adjustment						$0
2065	Other Electric Plant Adjustment						$0
2070	Other Utility Plant						$0
2075	Non-Utility Property Owned or Under Capital Leases						$0
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment						($52,174,686)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles						($6,446,650)

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment						$0
2160	Accumulated Amortization of Other Utility Plant						$0
2180	Accumulated Amortization of Non-Utility Property						$0
2205	Accounts Payable						($98,242,638)
2208	Customer Credit Balances						$0
2210	Current Portion of Customer Deposits						$0
2215	Dividends Declared						$0
2220	Miscellaneous Current and Accrued Liabilities						($9,584,600)
2225	Notes and Loans Payable						$0
2240	Accounts Payable to Associated Companies						$0
2242	Notes Payable to Associated Companies						$0
2250	Debt Retirement Charges(DRC) Payable						$0
2252	Transmission Charges Payable						$0
2254	Electrical Safety Authority Fees Payable						$0
2256	Independent Market Operator Fees and Penalties Payable						$0
2260	Current Portion of Long Term Debt						$0
2262	Ontario Hydro Debt - Current Portion						$0
2264	Pensions and Employee Benefits - Current Portion						$0
2268	Accrued Interest on Long Term Debt						($2,822,453)
2270	Matured Long Term Debt						$0
2272	Matured Interest on Long Term Debt						$0
2285	Obligations Under Capital Leases--Current						$0
2290	Commodity Taxes						$0
2292	Payroll Deductions / Expenses Payable						$0
2294	Accrual for Taxes, Payments in Lieu of Taxes, Etc.						($1,611,129)
2296	Future Income Taxes - Current						$1,649,780
2305	Accumulated Provision for Injuries and Damages						$0
2306	Employee Future Benefits						($5,327,808)
2308	Other Pensions - Past Service Liability						$0
2310	Vested Sick Leave Liability						$0
2315	Accumulated Provision for Rate Refunds						$0
2320	Other Miscellaneous Non-Current Liabilities						$0
2325	Obligations Under Capital Lease--Non-Current						$0
2330	Development Charge Fund						$0
2335	Long Term Customer Deposits						($21,500,000)
2340	Collateral Funds Liability						$0
2345	Unamortized Premium on Long Term Debt						$0
2348	O.M.E.R.S. - Past Service Liability - Long Term Portion						$0
2350	Future Income Tax - Non-Current						($320,000,000)
2405	Other Regulatory Liabilities						$0
2410	Deferred Gains from Disposition of Utility Plant						$0
2415	Unamortized Gain on Reacquired Debt						$0
2425	Other Deferred Credits						$0
2435	Accrued Rate-Payer Benefit						$0
2505	Debentures Outstanding - Long Term Portion						$0
2510	Debenture Advances						$0
2515	Reacquired Bonds						$0
2520	Other Long Term Debt						$0
2525	Term Bank Loans - Long Term Portion						$0
2530	Ontario Hydro Debt Outstanding - Long Term Portion						$0
2550	Advances from Associated Companies						$0
3005	Common Shares Issued						$0
3008	Preference Shares Issued						$0
3010	Contributed Surplus						$0
3020	Donations Received						$0
3022	Development Charges Transferred to Equity						$0
3026	Capital Stock Held in Treasury						$0
3030	Miscellaneous Paid-In Capital						$0
3035	Installments Received on Capital Stock						$0
3040	Appropriated Retained Earnings						$0
3045	Unappropriated Retained Earnings						($211,575,731)
3046	Balance Transferred From Income			$16,840,733		$0	($22,868,885)
3047	Appropriations of Retained Earnings - Current Period						$0
3048	Dividends Payable-Preference Shares						$0

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
3049	Dividends Payable-Common Shares						$0
3055	Adjustment to Retained Earnings						$0
3065	Unappropriated Undistributed Subsidiary Earnings						$0
4006	Residential Energy Sales						($124,539,983)
4010	Commercial Energy Sales						($950,433)
4015	Industrial Energy Sales						$0
4020	Energy Sales to Large Users						($79,411,680)
4025	Street Lighting Energy Sales						($1,592,916)
4030	Sentinel Lighting Energy Sales						$0
4035	General Energy Sales						($390,275,059)
4040	Other Energy Sales to Public Authorities						$0
4045	Energy Sales to Railroads and Railways						$0
4050	Revenue Adjustment						$0
4055	Energy Sales for Resale						($1,689,214)
4060	Interdepartmental Energy Sales						$0
4062	Billed WMS						($50,040,863)
4064	Billed-One-Time						$0
4066	Billed NW						($46,101,252)
4068	Billed CN						($38,678,600)
4080	Distribution Services Revenue			($13,617,464)	$535,964		($114,544,654)
4080-1	Revenue from Rates						
4080-2	SSS Admin Charge				($535,964)		($535,964)
4082	Retail Services Revenues						($186,631)
4084	Service Transaction Requests (STR) Revenues						($6,100)
4090	Electric Services Incidental to Energy Sales						$0
4105	Transmission Charges Revenue						$0
4110	Transmission Services Revenue						$0
4205	Interdepartmental Rents						$0
4210	Rent from Electric Property						($532,000)
4215	Other Utility Operating Income						$0
4220	Other Electric Revenues						$0
4225	Late Payment Charges						($1,800,000)
4230	Sales of Water and Water Power						$0
4235	Miscellaneous Service Revenues				$470,000		($766,783)
4235-1	Account Set Up Charges				($470,000)		($470,000)
4235-90	Miscellaneous Service Revenues - Residual						$0
4240	Provision for Rate Refunds						$0
4245	Government Assistance Directly Credited to Income						$0
4305	Regulatory Debits						$0
4310	Regulatory Credits						$0
4315	Revenues from Electric Plant Leased to Others						$0
4320	Expenses of Electric Plant Leased to Others						$0
4325	Revenues from Merchandise, Jobbing, Etc.						$0
4330	Costs and Expenses of Merchandising, Jobbing, Etc.						$0
4335	Profits and Losses from Financial Instrument Hedges						$0
4340	Profits and Losses from Financial Instrument Investments						$0
4345	Gains from Disposition of Future Use Utility Plant						$0
4350	Losses from Disposition of Future Use Utility Plant						$0
4355	Gain on Disposition of Utility and Other Property						($161,000)
4360	Loss on Disposition of Utility and Other Property						$0
4365	Gains from Disposition of Allowances for Emission						$0
4370	Losses from Disposition of Allowances for Emission						$0
4375	Revenues from Non-Utility Operations						($22,655,000)
4380	Expenses of Non-Utility Operations						$22,655,000
4385	Non-Utility Rental Income						$0
4390	Miscellaneous Non-Operating Income						($321,000)
4395	Rate-Payer Benefit Including Interest						$0
4398	Foreign Exchange Gains and Losses, Including Amortization						$0
4405	Interest and Dividend Income						($50,207)
4415	Equity in Earnings of Subsidiary Companies						$0
4505	Operation Supervision and Engineering						$0
4510	Fuel						$0
4515	Steam Expense						$0
4520	Steam From Other Sources						$0
4525	Steam Transferred--Credit						$0

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
4530	Electric Expense						$0
4535	Water For Power						$0
4540	Water Power Taxes						$0
4545	Hydraulic Expenses						$0
4550	Generation Expense						($346,270)
4555	Miscellaneous Power Generation Expenses						$0
4560	Rents						$0
4565	Allowances for Emissions						$0
4605	Maintenance Supervision and Engineering						$0
4610	Maintenance of Structures						$0
4615	Maintenance of Boiler Plant						$0
4620	Maintenance of Electric Plant						$0
4625	Maintenance of Reservoirs, Dams and Waterways						$0
4630	Maintenance of Water Wheels, Turbines and Generators						$0
4635	Maintenance of Generating and Electric Plant						$0
4640	Maintenance of Miscellaneous Power Generation Plant						$0
4705	Power Purchased						$382,755,711
4708	Charges-WMS						$265,744,435
4710	Cost of Power Adjustments						$0
4712	Charges-One-Time						$0
4714	Charges-NW						$46,101,252
4715	System Control and Load Dispatching						$0
4716	Charges-CN						$38,678,600
4720	Other Expenses						$0
4725	Competition Transition Expense						$0
4730	Rural Rate Assistance Expense						$0
4750	Charges-LV						$0
4805	Operation Supervision and Engineering						$0
4810	Load Dispatching						$0
4815	Station Buildings and Fixtures Expenses						$0
4820	Transformer Station Equipment - Operating Labour						$0
4825	Transformer Station Equipment - Operating Supplies and Expense						$0
4830	Overhead Line Expenses						$0
4835	Underground Line Expenses						$0
4840	Transmission of Electricity by Others						$0
4845	Miscellaneous Transmission Expense						$0
4850	Rents						$0
4905	Maintenance Supervision and Engineering						$0
4910	Maintenance of Transformer Station Buildings and Fixtures						$0
4916	Maintenance of Transformer Station Equipment						$0
4930	Maintenance of Towers, Poles and Fixtures						$0
4935	Maintenance of Overhead Conductors and Devices						$0
4940	Maintenance of Overhead Lines - Right of Way						$0
4945	Maintenance of Overhead Lines - Roads and Trails Repairs						$0
4950	Maintenance of Overhead Lines - Snow Removal from Roads and Trails						$0
4960	Maintenance of Underground Lines						$0
4965	Maintenance of Miscellaneous Transmission Plant						$0
5005	Operation Supervision and Engineering						$2,528,872
5010	Load Dispatching						$2,489,936
5012	Station Buildings and Fixtures Expense						$0
5014	Transformer Station Equipment - Operation Labour						$0
5015	Transformer Station Equipment - Operation Supplies and Expenses						$0
5016	Distribution Station Equipment - Operation Labour						$1,544,169
5017	Distribution Station Equipment - Operation Supplies and Expenses						$166,820
5020	Overhead Distribution Lines and Feeders - Operation Labour						$1,414,161
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses						$309,967
5030	Overhead Subtransmission Feeders - Operation						$0

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
5035	Overhead Distribution Transformers- Operation						$0
5040	Underground Distribution Lines and Feeders - Operation Labour						$3,211,590
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses						$286,880
5050	Underground Subtransmission Feeders - Operation						$0
5055	Underground Distribution Transformers - Operation						$0
5060	Street Lighting and Signal System Expense						$0
5065	Meter Expense						$1,006,569
5070	Customer Premises - Operation Labour						$1,629,935
5075	Customer Premises - Materials and Expenses						$86,540
5085	Miscellaneous Distribution Expense						$2,566,773
5090	Underground Distribution Lines and Feeders - Rental Paid						$0
5095	Overhead Distribution Lines and Feeders - Rental Paid						$0
5096	Other Rent						$165,000
5105	Maintenance Supervision and Engineering						$0
5110	Maintenance of Buildings and Fixtures - Distribution Stations						$0
5112	Maintenance of Transformer Station Equipment						$0
5114	Maintenance of Distribution Station Equipment						$0
5120	Maintenance of Poles, Towers and Fixtures						$0
5125	Maintenance of Overhead Conductors and Devices						$0
5130	Maintenance of Overhead Services						$2,679,514
5135	Overhead Distribution Lines and Feeders - Right of Way						$965,194
5145	Maintenance of Underground Conduit						$0
5150	Maintenance of Underground Conductors and Devices						$0
5155	Maintenance of Underground Services						$0
5160	Maintenance of Line Transformers						$0
5165	Maintenance of Street Lighting and Signal Systems						$0
5170	Sentinel Lights - Labour						$0
5172	Sentinel Lights - Materials and Expenses						$0
5175	Maintenance of Meters						$1,801,916
5178	Customer Installations Expenses- Leased Property						$0
5185	Water Heater Rentals - Labour						$0
5186	Water Heater Rentals - Materials and Expenses						$0
5190	Water Heater Controls - Labour						$0
5192	Water Heater Controls - Materials and Expenses						$0
5195	Maintenance of Other Installations on Customer Premises						$0
5205	Purchase of Transmission and System Services						$0
5210	Transmission Charges						$0
5215	Transmission Charges Recovered						$0
5305	Supervision						$3,842,550
5310	Meter Reading Expense						$24,000
5315	Customer Billing						$4,247,244
5320	Collecting						$0
5325	Collecting- Cash Over and Short						$0
5330	Collection Charges						$0
5335	Bad Debt Expense						$3,550,000
5340	Miscellaneous Customer Accounts Expenses						$350,111
5405	Supervision						$0
5410	Community Relations - Sundry						$0
5415	Energy Conservation						$0
5420	Community Safety Program						$0
5425	Miscellaneous Customer Service and Informational Expenses						$0
5505	Supervision						$0
5510	Demonstrating and Selling Expense						$0
5515	Advertising Expense						$0
5520	Miscellaneous Sales Expense						$0
5605	Executive Salaries and Expenses						$514,155
5610	Management Salaries and Expenses						$5,530,836
5615	General Administrative Salaries and Expenses						$11,365,039

USoA Account #	Accounts		Forecast Financial Statement	Model Adjustments	Reclassify accounts	Direct Allocation	Reclassified Balance
5620	Office Supplies and Expenses						$0
5625	Administrative Expense Transferred Credit						($4,337,299)
5630	Outside Services Employed						$0
5635	Property Insurance						$0
5640	Injuries and Damages						$1,086,443
5645	Employee Pensions and Benefits						$0
5650	Franchise Requirements						$0
5655	Regulatory Expenses						$1,091,500
5660	General Advertising Expenses						$0
5665	Miscellaneous General Expenses						$313,020
5670	Rent						$0
5675	Maintenance of General Plant						$9,219,951
5680	Electrical Safety Authority Fees						$97,850
5681	IFRS Placeholder Expense Account						$0
5682	IFRS Placeholder Expense Account						$0
5683	IFRS Placeholder Expense Account						$0
5684	IFRS Placeholder Expense Account						$0
5685	Independent Market Operator Fees and Penalties						$0
5705	Amortization Expense - Property, Plant, and Equipment						$25,575,554
5710	Amortization of Limited Term Electric Plant						$0
5715	Amortization of Intangibles and Other Electric Plant						$3,197,218
5720	Amortization of Electric Plant Acquisition Adjustments						$0
5725	Miscellaneous Amortization						$0
5730	Amortization of Unrecovered Plant and Regulatory Study Costs						$0
5735	Amortization of Deferred Development Costs						$0
5740	Amortization of Deferred Charges						$0
6005	Interest on Long Term Debt			($16,096,800)		$0	$18,395,000
6010	Amortization of Debt Discount and Expense						$0
6015	Amortization of Premium on Debt Credit						$0
6020	Amortization of Loss on Reacquired Debt						$0
6025	Amortization of Gain on Reacquired Debt--Credit						$0
6030	Interest on Debt to Associated Companies						$0
6035	Other Interest Expense						$316,099
6040	Allowance for Borrowed Funds Used During Construction--Credit						($50,407)
6042	Allowance For Other Funds Used During Construction						$0
6045	Interest Expense on Capital Lease Obligations						$0
6105	Taxes Other Than Income Taxes						$1,200,000
6110	Income Taxes			($2,815,000)		$0	$2,981,000
6115	Provision for Future Income Taxes						$2,298,000
6205	Donations						$150,000
6210	Life Insurance						$0
6215	Penalties						$0
6225	Other Deductions						$0
6305	Extraordinary Income		$0				$0
6310	Extraordinary Deductions		$0				$0
6315	Income Taxes, Extraordinary Items		$0				$0
6405	Discontinues Operations - Income/ Gains		$0				$0
6410	Discontinued Operations - Deductions/ Losses		$0				$0
6415	Income Taxes, Discontinued Operations		$0				$0
			($20,918,647)	($15,688,532)			
				$16,840,733	$0		
				($32,529,264)			
					Reclassification Equals to Zero. O.K. to Proceed.		
	Asset Accounts Directly Allocated					$0	

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet I4 Break Out Worksheet - Run 2

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

$0

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G14	$519,647,261

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description		BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$0		-	-					-				
1805	Land	$0		$0	-									
1805-1	Land Station >50 kV		0.00%	$0	-					-				
1805-2	Land Station <50 kV		100.00%	$0	-					-				
1806	Land Rights	$0		$0	-									
1806-1	Land Rights Station >50 kV		0.00%	$0	-					-				
1806-2	Land Rights Station <50 kV		100.00%	$0	-					-				
1808	Buildings and Fixtures	$35,768,173		($35,768,173)	-									
1808-1	Buildings and Fixtures > 50 kV		0.00%	$0	-									
1808-2	Buildings and Fixtures < 50 kV		100.00%	$35,768,173	35,768,173			$ (2,122,775)		33,645,398	$ 1,315,706			
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV		0.00%	$0	-					-				
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0		$0	-					-				
1820	Distribution Station Equipment - Normally Primary below 50 kV	$65,285,285		($65,285,285)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-			$ -		-	$ -			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		90.73%	$59,233,339	59,233,339			$ (4,417,941)		54,815,398	$ 1,794,940			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		9.27%	$6,051,946	6,051,946			$ (451,387)		5,600,559	$ 183,391			
1825	Storage Battery Equipment	$0		$0	-									
1825-1	Storage Battery Equipment > 50 kV			$0	-					-				
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$90,766,499		($90,766,499)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		0.00%	$0	-	$ -	$ -	$ -		-	$ -			
1830-4	Poles, Towers and Fixtures - Primary		71.84%	$65,206,653	65,206,653	$ (1,778,985)	$ 50,625	$ (3,911,865)		59,566,448	$ 1,901,910			
1830-5	Poles, Towers and Fixtures - Secondary		28.16%	$25,559,846	25,559,846	$ (697,323)	$ 19,844	$ (1,533,381)		23,348,986	$ 745,515			
1835	Overhead Conductors and Devices	$16,049,944		($16,049,944)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		0.00%	$0	-	$ -	$ -	$ -		-	$ -			
1835-4	Overhead Conductors and Devices - Primary		71.84%	$11,530,279	11,530,279	$ (195,632)	$ 7,012	$ (907,345)		10,434,314	$ 609,629			
1835-5	Overhead Conductors and Devices - Secondary		28.16%	$4,519,664	4,519,664	$ (76,684)	$ 2,749	$ (355,663)		4,090,065	$ 239,042			
1840	Underground Conduit	$36,710,743		($36,710,743)	-									
1840-3	Underground Conduit - Bulk Delivery		0.00%	$0	-					-				
1840-4	Underground Conduit - Primary		75.00%	$27,533,057	27,533,057	$ (657,305)	$ 19,762	$ (1,592,218)		25,303,304	$ 672,579			
1840-5	Underground Conduit - Secondary		25.00%	$9,177,686	9,177,686	$ (219,102)	$ 6,587	$ (530,737)		8,434,435	$ 224,193			
1845	Underground Conductors and Devices	$159,631,558		($159,631,558)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery		0.00%	$0	-	$ -	$ -	$ -		-	$ -			
1845-4	Underground Conductors and Devices - Primary		75.00%	$119,723,668	119,723,668	$ (2,795,536)	$ 122,223	$ (10,770,646)		106,279,716	$ 5,095,509			
1845-5	Underground Conductors and Devices - Secondary		25.00%	$39,907,889	39,907,889	$ (931,845)	$ 40,741	$ (3,590,213)		35,426,572	$ 1,698,503			
1850	Line Transformers	$57,276,606		$0	57,276,606	$ (833,059)	$ 24,704	$ (5,288,282)		51,179,969	$ 2,630,107			
1855	Services	$15,157,937		$0	15,157,937	$ (367,620)	$ 13,477	$ (1,159,603)		13,644,192	$ 559,354			
1860	Meters	$38,015,782		$0	38,015,782	$ (173,388)	$ 9,336	$ (6,002,383)		31,849,348	$ 3,035,846			
1880	IFRS Placeholder Account	$0		$0	-					-				
	Total	**$514,662,525**		**$0**	**$514,662,525**	**($8,726,459)**	**$317,061**	**($42,634,424)**	**$0**	**463,618,704**	**$20,706,423**	**$0**	**$0**	**$0**
	SUB TOTAL from I3	**$514,662,525**												

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet L4 Break Out Worksheet - Run 2

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
Please see Instructions tab for detailed instructions*

$0

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G14	$519,647,261

RATE BASE AND DISTRIBUTION ASSETS

Account	Description	BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
			BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	5705 Amortization Expense - Property, Plant, and Equipment	5710 Amortization of Limited Term Electric Plant	5715 Amortization of Intangibles and Other Electric Plant	5720 Amortization of Electric Plant Acquisition Adjustments
1905	Land	$10,401,532			10,401,532					$ 10,401,532				
1906	Land Rights	$0			-					$ -				
1908	Buildings and Fixtures	$0			-					$ -				
1910	Leasehold Improvements	$0			-					$ -				
1915	Office Furniture and Equipment	$5,260,385			5,260,385			($1,567,726)		$ 3,692,659	$ 734,835			
1920	Computer Equipment - Hardware	$6,065,439			6,065,439			($2,832,286)		$ 3,233,153	$ 1,482,321			
1925	Computer Software	$25,743,790			25,743,790				($6,446,650)	$ 19,297,140	-		$ 3,197,218	
1930	Transportation Equipment	$9,541,776			9,541,776			($2,721,070)		$ 6,820,706	$ 1,405,237			
1935	Stores Equipment	$0			-					$ -				
1940	Tools, Shop and Garage Equipment	$1,463,130			1,463,130			($434,523)		$ 1,028,607	$ 199,481			
1945	Measurement and Testing Equipment	$0			-					$ -				
1950	Power Operated Equipment	$0			-					$ -				
1955	Communication Equipment	$0			-					$ -				
1960	Miscellaneous Equipment	$0			-					$ -				
1970	Load Management Controls - Customer Premises	$0			-					$ -				
1975	Load Management Controls - Utility Premises	$0			-					$ -				
1980	System Supervisory Equipment	$13,856,478			13,856,478			($2,301,719)		$ 11,554,759	$ 1,047,257			
1990	Other Tangible Property	$0			-					$ -				
2005	Property Under Capital Leases	$0			-					$ -				
2010	Electric Plant Purchased or Sold	$0			-					$ -	-			
	Total	$72,332,531		$0	$72,332,531	$0	$0	($9,857,324)	($6,446,650)	$56,028,557	$4,869,131	$0	$3,197,218	$0
	SUB TOTAL from I3	$72,332,531												
	I3 Directly Allocated	$0												
	Grand Total	$586,995,056		$0	$586,995,056	($8,726,459)	$317,061	($52,491,748)	($6,446,650)	$519,647,261	$25,575,554	$0	$3,197,218	$0

To be Prorated

		#REF!												
1995	Contributed Capital - 1995	($8,726,459)												
						$8,726,459	Balanced							
2105	Accumulated Depreciation - 2105	($52,174,686)					$0	$52,174,686	Balanced					
2120	Accumulated Depreciation - 2120	($6,446,650)							$6,446,650	Balanced				
	Total	($67,347,795)												
	Net Assets	$519,647,261	Net Fixed Assets Match											

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$25,575,554									($25,575,554)	Balanced		
5710	Amortization of Limited Term Electric Plant	$0										$0	Balanced	
5715	Amortization of Intangibles and Other Electric Plant	$3,197,218											($3,197,218)	Balanced
5720	Amortization of Electric Plant Acquisition Adjustments	$0												$0 Balanced
	Total Amortization Expense	$28,772,772												

Ontario

2013 COST ALLOCATION

Enersource Hydro Mississauga

EB-2012-0033

Friday, April 27, 2012

Sheet I5.1 Miscellaneous Data Worksheet - Run 2

kMs of Roads in Service Area Where Distribution Lines Exist	2551.71
Deemed Equity Component of Rate Base (%)	40%
Working Capital Allowance to be included in Rate Base	13.5%
Portion of pole leasing revenue from Secondary - Remainder assumed to be Primary (%)	28%

	1	2	4	5	6	7	9
	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
Insert Approved Monthly Service Charge	12.64	40.70	70.63	1,539.04	13,857.67	1.34	10.69

ENERSOURCE HYDRO MISSISSAUGA
EB-2012-0033
Friday, April 27, 2012
Sheet I5.2 Weighting Factors Worksheet - Run 2

	1	2	4	5	6	7	9
	Residential	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
Insert Weighting Factor for Services	1	2	10	10	30	1	1
Insert Weighting Factor for Billing and Collecting	1	2	7	7	15	1	1

defaults from eb-2010-0219 board staff's implementation document

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet I6.1 Revenue Worksheet - Run 2

Total kWhs from Load Forecast	7,451,768,707
Total kWs from Load Forecast	13,083,516
Deficiency from RRWF	- 14,742,550
Miscellaneous Revenue	4,829,685

			1	2	4	5	6	7	9
	ID	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
Billing Data									
Forecast kWh	CEN	7,451,768,707	1,423,857,475	612,188,101	2,139,657,427	2,249,538,514	997,124,443	19,019,721	10,383,027
Forecast kW	CDEM	13,083,516			6,142,022	5,154,338	1,737,267	49,889	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		4,994,904	-	-	424,663	2,832,975	1,737,267		
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	7,451,768,707	1,423,857,475	612,188,101	2,139,657,427	2,249,538,514	997,124,443	19,019,721	10,383,027
kWh - 30 year weather normalized amount		7,452,317,082	1,421,380,267	612,401,754	2,140,531,792	2,225,035,934	1,023,548,458	19,032,452	10,386,424
Existing Monthly Charge			$12.64	$40.70	$70.63	$1,539.04	$13,857.67	$1.34	$10.69
Existing Distribution kWh Rate			$0.0119	$0.0116	$0.0000	$0.0000	$0.0000	$0.0000	$0.0195
Existing Distribution kW Rate					$4.2044	$2.0981	$2.9225	$10.2587	
Existing TFOA Rate					$0.40	$0.40	$0.40	$0.40	
Additional Charges									
Distribution Revenue from Rates		$116,542,615	$43,770,787	$15,747,527	$29,171,380	$19,383,691	$6,573,790	$1,315,572	$579,869
Transformer Ownership Allowance		$1,997,962	$0	$0	$169,865	$1,133,190	$694,907	$0	$0
Net Class Revenue	CREV	$114,544,654	$43,770,787	$15,747,527	$29,001,515	$18,250,501	$5,878,883	$1,315,572	$579,869
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		114,443,922	43,694,635	15,753,023	29,013,366	18,051,712	6,034,675	1,316,452	580,059

Weather Normalized Data from Hydro One	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
kWh - 30 year weather normalized amount	7,698,594,205	1,472,549,957	634,448,217	2,217,590,936	2,305,137,228	1,038,389,910	19,717,621	10,760,336
Loss Factor		1.0360	1.0360	1.0360	1.0360	1.0145	1.0360	1.0360

2013 COST ALLOCATION
Enersource Hydro Mississauga
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Sheet I6.2 Customer Data Worksheet - Run 2

			1	2	4	5	6	7	9
	ID	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$2,405,390	$1,206,738	$733,747	$387,154	$76,645	$0	$0	$1,105
Late Payment 3 Year Historical Average	LPHA	$1,268,340	$672,232	$221,635	$215,792	$156,507	$0	$0	$2,173
Number of Bills	CNB	1,328,994	1,061,190	212,436	47,400	5,568	108	12	2,280
Number of Devices								49,986	2,942
Number of Connections (Unmetered)	CCON	13,824						10,882	2,942
Total Number of Customers	CCA	199,182	176,865	17,703	3,950	464	9	1	190
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	199,093	176,865	17,616	3,948	464	9	1	190
Line Transformer Customer Base	CCLT	198,616	176,865	17,478	3,789	294	-	-	190
Secondary Customer Base	CCS	198,616	176,865	17,478	3,789	294	-	-	190
Weighted - Services	CWCS	266,475	176,865	34,956	37,890	2,940	-	10,882	2,942
Weighted Meter -Capital	CWMC	24,564,548	14,758,240	7,208,212	2,185,047	386,238	26,811	-	-
Weighted Meter Reading	CWMR	1,987,998	1,097,160	214,181	467,525	188,503	20,629	-	-
Weighted Bills	CWNB	1,860,750	1,061,190	424,872	331,800	38,976	1,620	12	2,280

Bad Debt Data

Historic Year: 2009		1,354,859	679,707	413,290	218,068	43,171	-	-	622
Historic Year: 2010		2,662,875	1,335,914	812,291	428,597	84,850	-	-	1,223
Historic Year: 2011		3,198,436	1,604,594	975,660	514,798	101,915	-	-	1,469
Three-year average		**2,405,390**	**1,206,738**	**733,747**	**387,154**	**76,645**	**-**	**-**	**1,105**

2013 COST ALLOCATION
Enersource Hydro Mississauga
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Friday, April 27, 2012
Sheet I7.1 Meter Capital Worksheet - Run 2

		Residential			GS < 50kW			GS 50 - 499kW			GS 500 - 4999kW			Large User > 5MW			Street Light			Unmetered			TOTAL		
		1	2	3	1	2	3	1	2	3	1	2	3	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	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				60.08%			29%			9%			2%			0%			0%			0%			100%
Cost Relative to Residential Average Cost				1.00			4.92			6.71			8.99			9.22			-			-			1.48
Total		177,599	14,758,240	83	17,629	7,208,212	409	3,921	2,185,047	557	517	386,238	747	35	26,811	766	-	-	-	-	-	-	199,701	24,564,548	123
Meter Types	**Cost per Meter (Installed)**																								
Single Phase 200 Amp Urban	286	1,413	404,118		117	33,462		16	4,576		0	-		0	-			-			-		1,546	442,156	
Single Phase 200 Amp Urban CO-GEN	74	57	4,218		1	74		0	-		0	-		0	-			-			-		58	4,292	
3 Phase noIT w/Dem	302	0	-		36	10,872		102	30,804		0	-		0	-			-			-		138	41,676	
3 Phase noIT w/Dem+Mass Memory	758	0	-		1	758		2	1,516		1	758		0	-			-			-		4	3,032	
Demand with IT	336	0	-		6	2,016		209	70,224		0	-		1	336			-			-		216	72,576	
Demand with IT and Interval Capability Secondary or Primary	719	0	-		49	35,231		1,888	1,357,472		494	355,186		33	23,727			-			-		2,464	1,771,616	
Demand with IT and Interval Capability Secondary or Primary Bidirectional	2,748	0	-		1	2,748		9	24,732		9	24,732		1	2,748			-			-		20	54,960	
IMS 3 Phase Commercial with Demand no IT	95	0	-		14	1,330		0	-		0	-		0	-			-			-		14	1,330	
IMS 3 Phase Commercial with Demand with IT	108	2	216		0	-		7	756		0	-		0	-			-			-		9	972	
IMS Urban Meter	306	7,740	2,368,440		20	6,120		4	1,224		1	306		0	-			-			-		7,765	2,376,090	
Smart Meters	71	168,219	11,943,549		568	40,328		0	-		0	-		0	-			-			-		168,787	11,983,877	
Smart Meters with Demand no IT	436	13	5,668		13,127	5,723,372		466	203,176		0	-		0	-										
Smart Meters with Demand no IT Bidirectional	432	0	-		9	3,888		3	1,296		0	-		0	-										
Smart Meters with Demand with IT	438	0	-		1,904	833,952		807	353,466		12	5,256		0	-										
Smart Meter with IT	205	151	30,955		222	45,510		18	3,690		0	-		0	-										
Three-phase No demand	269	4	1,076		1,301	349,969		1	269		0	-		0	-			-			-		1,306	351,314	
Three-phase with demand	478	0	-		237	113,286		21	10,038		0	-		0	-			-			-		258	123,324	
Three-phase with demand with IT	331	0	-		16	5,296		368	121,808		0	-		0	-			-			-		384	127,104	

2013 COST ALLOCATION
Enersource Hydro Mississauga
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Friday, April 27, 2012
Sheet I7.2 Meter Reading Worksheet - Run 2

Weighting Factors based on Contractor Pricing

Description		1 Residential			2 GS < 50kW			4 GS 50 - 499kW			5 GS 500 - 4999kW			6 Large User > 5MW			7 Street Light			9 Unmetered			TOTAL		
		Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs	Units	Weighted Factor	Weighted Average Costs
	Allocation Percentage Weighted Factor			55.19%			10.77%			23.52%			9.48%			1.04%			0.00%			0.00%			100.00%
	Cost Relative to Residential Average Cost			1.00			1.00			9.50			29.50			49.00			0.00			0.00			90.01
	Total	1,097,160	1,097,160	1.00	214,181	214,181	1.00	49,190	467,525	9.50	6,389	188,503	29.50	421	20,629	49.00	-	-	0	-	-	0	1,367,341	1,987,998	90
	Factor																								
Residential - Urban - Outside	1.00		0			0			0			0			0			0			0		-	-	
Residential - Urban - Outside with other services	1.00		0			0			0			0			0			0			0		-	-	
Residential - Urban - Inside	2.00		0			0			0			0			0			0			0		-	-	
Residential - Urban - Inside - with other services	1.00		0			0			0			0			0			0			0		-	-	
Residential - Rural - Outside	3.00		0			0			0			0			0			0			0		-	-	
Residential - Rural - Outside with other services	2.00		0			0			0			0			0			0			0		-	-	
LDC Specific 1			0			0			0			0			0		0	0		0	0		-	-	
LDC Specific 2			0			0			0			0			0			0			0		-	-	
GS - Walking	8.00		0			0		47,385	379,080		3,038	24,304			0			0			0		50,423	403,384	
GS - Walking - with other services	3.00		0			0			0			0			0			0			0		-	-	
GS - Vehicle with other services --- TOU Read	3.00		0			0			0			0			0			0			0		-	-	
GS - Vehicle with other services	3.00		0			0			0			0			0			0			0		-	-	
Smart Meter	1.00	1,097,160	1,097,160		214,181	214,181			0			0			0			0			0		1,311,341	1,311,341	
LDC Specific 4	0.00		0			0			0			0			0			0			0		-	-	
Interval	49.00		0			0		1,805	88,445		3,351	164,199		421	20,629			0			0		5,577	273,273	
LDC Specific 5			0			0			0			0			0			0			0		-	-	
LDC Specific 6			0			0			0			0			0			0			0		-	-	

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet I8 Demand Data Worksheet - Run 2

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

NOTE FROM 2008 MODEL:

LOSSES:

Interpretation per meeting at OEB with Neil Mather:
DCP is in fact the TCP
TCP is the load of the TS before the meter, therefore gross up b | SFLF | 1.0045
TCP is only significant if LDC owns TS

NCP

Primary = DNCP - SFLF	DLF - non LU	1.0386
Secondary = PNCP-DLF	DLF - LU	1.0100

Customer Classes		Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	1,256,471	307,101	74,904	426,933	337,956	108,453	-	1,124
Bulk Delivery CP	BCP1	1,250,842	305,725	74,569	425,021	336,442	107,967	-	1,119
Total Sytem CP	DCP1	1,250,842	305,725	74,569	425,021	336,442	107,967	-	1,119
4 CP									
Transformation CP	TCP4	4,766,201	1,086,680	299,316	1,594,140	1,347,759	433,811	-	4,495
Bulk Delivery CP	BCP4	4,744,849	1,081,812	297,975	1,586,998	1,341,721	431,868	-	4,475
Total Sytem CP	DCP4	4,744,849	1,081,812	297,975	1,586,998	1,341,721	431,868	-	4,475
12 CP									
Transformation CP	TCP12	13,340,918	2,990,226	859,817	4,319,337	3,727,185	1,407,211	22,559	14,582
Bulk Delivery CP	BCP12	13,281,153	2,976,830	855,965	4,299,987	3,710,488	1,400,907	22,458	14,517
Total Sytem CP	DCP12	13,281,153	2,976,830	855,965	4,299,987	3,710,488	1,400,907	22,458	14,517
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	1,383,636	368,715	90,149	425,021	363,441	130,185	4,777	1,349
Primary NCP	PNCP1	1,377,438	367,063	89,745	423,117	361,813	129,602	4,756	1,343
Line Transformer NCP	LTNCP1	1,201,044	353,421	86,290	407,240	348,222		4,579	1,293
Secondary NCP	SNCP1	1,201,044	353,421	86,290	407,240	348,222	-	4,579	1,293
4 NCP									
Classification NCP from Load Data Provider	DNCP4	5,263,256	1,322,968	355,208	1,636,507	1,403,880	520,407	18,894	5,393
Primary NCP	PNCP4	5,239,678	1,317,041	353,616	1,629,175	1,397,590	518,076	18,810	5,369
Line Transformer NCP	LTNCP4	4,044,081	1,268,093	338,067	1,505,966	908,675		18,111	5,169
Secondary NCP	SNCP4	4,044,081	1,268,093	338,067	1,505,966	908,675	-	18,111	5,169
12 NCP									
Classification NCP from Load Data Provider	DNCP12	14,621,159	3,462,435	1,009,205	4,587,026	3,934,159	1,556,636	55,566	16,131
Primary NCP	PNCP12	14,555,658	3,446,924	1,004,684	4,566,477	3,916,535	1,549,662	55,317	16,058
Line Transformer NCP	LTNCP12	12,502,109	3,318,818	960,507	4,389,924	3,764,137		53,262	15,462
Secondary NCP	SNCP12	12,502,109	3,318,818	960,507	4,389,924	3,764,137	-	53,262	15,462

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet I9 Direct Allocation Worksheet - Run 2

Instructions:
More Instructions provided on the first tab in this workbook.

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Instructions: **To Allocate Capital Contributions by Rate Classification, Input Allocation on Next Line**										
1995	Contributions and Grants - Credit	$0	Yes							
Instructions: **The Following is Used to Allocate Directly Allocated Costs from I3 to Rate Classifications**										
1805	Land	$0	Yes							
1806	Land Rights	$0	Yes							
1808	Buildings and Fixtures	$0	Yes							
1810	Leasehold Improvements	$0	Yes							
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	Yes							
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	Yes							
1825	Storage Battery Equipment	$0	Yes							
1830	Poles, Towers and Fixtures	$0	Yes							
1835	Overhead Conductors and Devices	$0	Yes							
1840	Underground Conduit	$0	Yes							
1845	Underground Conductors and Devices	$0	Yes							
1850	Line Transformers	$0	Yes							
1855	Services	$0	Yes							
1860	Meters	$0	Yes							
1555	IFRS Placeholder Asset Account	$0	Yes							
1905	Land	$0	Yes							
1906	Land Rights	$0	Yes							
1908	Buildings and Fixtures	$0	Yes							
1910	Leasehold Improvements	$0	Yes							
1915	Office Furniture and Equipment	$0	Yes							
1920	Computer Equipment - Hardware	$0	Yes							
1925	Computer Software	$0	Yes							
1930	Transportation Equipment	$0	Yes							
1935	Stores Equipment	$0	Yes							
1940	Tools, Shop and Garage Equipment	$0	Yes							
1945	Measurement and Testing Equipment	$0	Yes							
1950	Power Operated Equipment	$0	Yes							
1955	Communication Equipment	$0	Yes							
1960	Miscellaneous Equipment	$0	Yes							
1970	Load Management Controls - Customer Premises	$0	Yes							
1975	Load Management Controls - Utility Premises	$0	Yes							
1980	System Supervisory Equipment	$0	Yes							
1990	Other Tangible Property	$0	Yes							
2005	Property Under Capital Leases	$0	Yes							
2010	Electric Plant Purchased or Sold	$0	Yes							
2050	Completed Construction Not Classified--Electric	$0	Yes							

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	$0	Yes							
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	$0	Yes							
	Directly Allocated Net Fixed Assets			**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5005	Operation Supervision and Engineering	$0	Yes							
5010	Load Dispatching	$0	Yes							
5012	Station Buildings and Fixtures Expense	$0	Yes							
5014	Transformer Station Equipment - Operation Labour	$0	Yes							
5015	Transformer Station Equipment - Operation Supplies and Expenses	$0	Yes							
5016	Distribution Station Equipment - Operation Labour	$0	Yes							
5017	Distribution Station Equipment - Operation Supplies and Expenses	$0	Yes							
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	Yes							
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	Yes							
5030	Overhead Subtransmission Feeders - Operation	$0	Yes							
5035	Overhead Distribution Transformers- Operation	$0	Yes							
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	Yes							
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	Yes							
5050	Underground Subtransmission Feeders - Operation	$0	Yes							
5055	Underground Distribution Transformers - Operation	$0	Yes							
5065	Meter Expense	$0	Yes							
5070	Customer Premises - Operation Labour	$0	Yes							
5075	Customer Premises - Materials and Expenses	$0	Yes							
5085	Miscellaneous Distribution Expense	$0	Yes							
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	Yes							
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	Yes							
5096	Other Rent	$0	Yes							
5105	Maintenance Supervision and Engineering	$0	Yes							
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$0	Yes							
5112	Maintenance of Transformer Station Equipment	$0	Yes							
5114	Maintenance of Distribution Station Equipment	$0	Yes							
5120	Maintenance of Poles, Towers and Fixtures	$0	Yes							
5125	Maintenance of Overhead Conductors and Devices	$0	Yes							
5130	Maintenance of Overhead Services	$0	Yes							
5135	Overhead Distribution Lines and Feeders - Right of Way	$0	Yes							
5145	Maintenance of Underground Conduit	$0	Yes							
5150	Maintenance of Underground Conductors and Devices	$0	Yes							

USoA Account #	Accounts	Direct Allocation	Total Allocated to Rate Classifications?	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
5155	Maintenance of Underground Services	$0	Yes							
5160	Maintenance of Line Transformers	$0	Yes							
5175	Maintenance of Meters	$0	Yes							
5305	Supervision	$0	Yes							
5310	Meter Reading Expense	$0	Yes							
5315	Customer Billing	$0	Yes							
5320	Collecting	$0	Yes							
5325	Collecting- Cash Over and Short	$0	Yes							
5330	Collection Charges	$0	Yes							
5335	Bad Debt Expense	$0	Yes							
5340	Miscellaneous Customer Accounts Expenses	$0	Yes							
5405	Supervision	$0	Yes							
5410	Community Relations - Sundry	$0	Yes							
5415	Energy Conservation	$0	Yes							
5420	Community Safety Program	$0	Yes							
5425	Miscellaneous Customer Service and Informational Expenses	$0	Yes							
5505	Supervision	$0	Yes							
5510	Demonstrating and Selling Expense	$0	Yes							
5515	Advertising Expense	$0	Yes							
5520	Miscellaneous Sales Expense	$0	Yes							
5605	Executive Salaries and Expenses	$0	Yes							
5610	Management Salaries and Expenses	$0	Yes							
5615	General Administrative Salaries and Expenses	$0	Yes							
5620	Office Supplies and Expenses	$0	Yes							
5625	Administrative Expense Transferred Credit	$0	Yes							
5630	Outside Services Employed	$0	Yes							
5635	Property Insurance	$0	Yes							
5640	Injuries and Damages	$0	Yes							
5645	Employee Pensions and Benefits	$0	Yes							
5650	Franchise Requirements	$0	Yes							
5655	Regulatory Expenses	$0	Yes							
5660	General Advertising Expenses	$0	Yes							
5665	Miscellaneous General Expenses	$0	Yes							
5670	Rent	$0	Yes							
5675	Maintenance of General Plant	$0	Yes							
5680	Electrical Safety Authority Fees	$0	Yes							
5682	IFRS Placeholder Expense Account	$0	Yes							
5705	Amortization Expense - Property, Plant, and Equipment	$0	Yes							
5710	Amortization of Limited Term Electric Plant	$0	Yes							
5715	Amortization of Intangibles and Other Electric Plant	$0	Yes							
5720	Amortization of Electric Plant Acquisition Adjustments	$0	Yes							
6105	Taxes Other Than Income Taxes	$0	Yes							
6205	Donations	$0	Yes							
6210	Life Insurance	$0	Yes							
6215	Penalties	$0	Yes							
6225	Other Deductions	$0	Yes							
	Total Expenses			$0	$0	$0	$0	$0	$0	$0
	Depreciation Expense			$0	$0	$0	$0	$0	$0	$0

			Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
Total Net Fixed Assets Excluding Gen Plant	**$514,662,525**	**Allocated**							
Approved Total PILs	**$2,981,000**	**$0**	$0	$0	$0	$0	$0	$0	$0
Approved Total Return on Debt	**$18,395,000**	**$0**	$0	$0	$0	$0	$0	$0	$0
Approved Total Return on Equity	**$22,868,885**	**$0**	$0	$0	$0	$0	$0	$0	$0
		Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O1 Revenue to Cost Summary Worksheet - Run 2

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
crev	Distribution Revenue at Existing Rates	$114,544,654	$43,770,787	$15,747,527	$29,001,515	$18,250,501	$5,878,883	$1,315,572	$579,869
mi	Miscellaneous Revenue (mi)	$4,829,685	$2,683,342	$794,920	$814,488	$426,661	$49,329	$44,131	$16,813
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$119,374,339	$46,454,129	$16,542,447	$29,816,003	$18,677,162	$5,928,213	$1,359,703	$596,682
	Factor required to recover deficiency (1 + D)	1.1287							
	Distribution Revenue at Status Quo Rates	$129,287,204	$49,404,337	$17,774,324	$32,734,175	$20,599,445	$6,635,529	$1,484,893	$654,501
	Miscellaneous Revenue (mi)	$4,829,685	$2,683,342	$794,920	$814,488	$426,661	$49,329	$44,131	$16,813
	Total Revenue at Status Quo Rates	$134,116,889	$52,087,679	$18,569,243	$33,548,663	$21,026,106	$6,684,858	$1,529,024	$671,314
	Expenses								
di	Distribution Costs (di)	$18,328,876	$7,734,504	$1,533,095	$4,511,453	$3,215,321	$929,596	$318,079	$86,828
cu	Customer Related Costs (cu)	$16,538,865	$9,721,350	$3,979,509	$2,363,667	$340,080	$10,735	$87,824	$35,701
ad	General and Administration (ad)	$26,231,491	$13,005,977	$4,066,162	$5,240,218	$2,780,657	$739,907	$306,432	$92,139
dep	Depreciation and Amortization (dep)	$28,772,772	$11,875,942	$2,964,329	$6,982,977	$5,099,573	$1,404,145	$349,026	$96,778
INPUT	PILs (INPUT)	$2,981,000	$1,178,618	$269,960	$756,627	$566,986	$161,087	$37,349	$10,373
INT	Interest	$18,395,000	$7,272,954	$1,665,857	$4,668,957	$3,498,729	$994,028	$230,470	$64,006
	Total Expenses	$111,248,004	$50,789,344	$14,478,911	$24,523,900	$15,501,346	$4,239,498	$1,329,180	$385,825
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$22,868,885	$9,041,823	$2,071,013	$5,804,504	$4,349,661	$1,235,787	$286,523	$79,574
	Revenue Requirement (includes NI)	$134,116,889	$59,831,168	$16,549,924	$30,328,404	$19,851,007	$5,475,286	$1,615,703	$465,398
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$514,662,525	$204,670,586	$47,222,167	$129,952,961	$97,097,543	$27,470,244	$6,457,021	$1,792,003
gp	General Plant - Gross	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
accum dep	Accumulated Depreciation	($58,621,336)	($24,091,824)	($5,994,736)	($14,277,757)	($10,457,074)	($2,893,965)	($709,504)	($196,476)
co	Capital Contribution	($8,726,459)	($3,730,272)	($715,984)	($2,136,701)	($1,557,836)	($401,992)	($144,302)	($39,372)
	Total Net Plant	$519,647,261	$205,488,394	$47,050,839	$131,886,250	$98,825,281	$28,072,687	$6,514,638	$1,809,173
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$733,279,998	$140,112,535	$60,241,442	$210,549,744	$221,362,426	$98,120,519	$1,871,607	$1,021,726
	OM&A Expenses	$61,099,232	$30,461,831	$9,578,765	$12,115,338	$6,336,057	$1,680,238	$712,335	$214,667
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	$794,379,230	$170,574,367	$69,820,207	$222,665,082	$227,698,483	$99,800,757	$2,583,942	$1,236,393
	Working Capital	$107,241,196	$23,027,539	$9,425,728	$30,059,786	$30,739,295	$13,473,102	$348,832	$166,913
	Total Rate Base	$626,888,457	$228,515,934	$56,476,567	$161,946,036	$129,564,576	$41,545,789	$6,863,470	$1,976,086
		Rate Base Input equals Output							
	Equity Component of Rate Base	$250,755,383	$91,406,373	$22,590,627	$64,778,414	$51,825,830	$16,618,316	$2,745,388	$790,434
	Net Income on Allocated Assets	$22,868,885	$1,298,335	$4,090,332	$9,024,763	$5,524,760	$2,445,360	$199,844	$285,490
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$22,868,885	$1,298,335	$4,090,332	$9,024,763	$5,524,760	$2,445,360	$199,844	$285,490
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	87.06%	112.20%	110.62%	105.92%	122.09%	94.64%	144.25%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($14,742,550)	($13,377,038)	($7,477)	($512,401)	($1,173,845)	$452,927	($256,000)	$131,284
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($7,743,488)	$2,019,319	$3,220,260	$1,175,099	$1,209,573	($86,679)	$205,916
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.12%	1.42%	18.11%	13.93%	10.66%	14.71%	7.28%	36.12%

2013 COST ALLOCATION

Enersource Hydro Mississauga

EB-2012-0033

Friday, April 27, 2012

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Run 2

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	4	5	6	7	9
	Residential	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
Customer Unit Cost per month - Avoided Cost	$3.75	$15.45	$25.56	-$2.26	$74.62	$0.66	$0.71
Customer Unit Cost per month - Directly Related	$5.95	$23.43	$44.09	$19.87	$135.37	$1.17	$1.33
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.67	$51.09	$121.59	$122.19	$652.63	$4.38	$8.60
Existing Approved Fixed Charge	$12.64	$40.70	$70.63	$1,539.04	$13,857.67	$1.34	$10.69

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O2.1 Line Transformer Worksheet - Run 2

Line Transformers Demand Unit Cost for PLCC
Adjustment to Customer Related Cost
Allocation by rate classification

		1	2	4	5	6	7	9
Description	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
Depreciation on Acct 1850 Line Transformers	$1,709,570	$454,615	$143,108	$692,186	$419,125	$0	$323	$213
Depreciation on General Plant Assigned to Line Transformers	$578,642	$154,139	$48,370	$234,204	$141,746	$0	$110	$73
Acct 5035 - Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5055 - Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5160 - Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$640,438	$170,308	$53,611	$259,306	$157,012	$0	$121	$80
Admin and General Assigned to Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
PILs on Line Transformers	$213,902	$56,882	$17,906	$86,606	$52,441	$0	$40	$27
Debt Return on Line Transformers	$1,319,934	$351,002	$110,492	$534,427	$323,600	$0	$249	$165
Equity Return on Line Transformers	$1,640,958	$436,369	$137,365	$664,406	$402,303	$0	$310	$205
Total	**$6,103,443**	**$1,623,314**	**$510,851**	**$2,471,135**	**$1,496,228**	**$0**	**$1,153**	**$761**
Line Tranformer NCP	3,704,481	985,109	310,103	1,499,904	908,205	0	700	462
PLCC Amount	339,600	282,984	27,965	6,062	470	0	17,411	4,707
Adjustment to Customer Related Cost for PLCC	**$559,609**	**$466,316**	**$46,068**	**$9,988**	**$775**	**$0**	**$28,703**	**$7,760**
General Plant - Gross Assets	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
General Plant - Accumulated Depreciation	($16,303,974)	($6,455,522)	($1,473,999)	($4,135,638)	($3,097,635)	($878,711)	($205,438)	($57,031)
General Plant - Net Fixed Assets	$56,028,557	$22,184,382	$5,065,392	$14,212,109	$10,645,013	$3,019,688	$705,985	$195,987
General Plant - Depreciation	$8,066,349	$3,193,853	$729,257	$2,046,096	$1,532,547	$434,740	$101,640	$28,216
Total Net Fixed Assets Excluding General Plant	**$463,618,704**	**$183,304,012**	**$41,985,446**	**$117,674,141**	**$88,180,268**	**$25,052,998**	**$5,808,653**	**$1,613,186**
Total Administration and General Expense	$26,231,495	$13,005,981	$4,066,162	$5,240,218	$2,780,657	$739,907	$306,432	$92,139
Total O&M	**$34,702,741**	**$17,373,250**	**$5,486,517**	**$6,842,586**	**$3,538,576**	**$935,881**	**$403,982**	**$121,949**
Line Transformer Rate Base								
Acct 1850 - Line Transformers - Gross Assets	$37,229,794	$9,900,280	$3,116,510	$15,073,933	$9,127,398	$0	$7,031	$4,642
Line Transformers - Accumulated Depreciation	($3,962,814)	($1,053,806)	($331,728)	($1,604,500)	($971,539)	$0	($748)	($494)
Line Transformers - Net Fixed Assets	$33,266,980	$8,846,474	$2,784,783	$13,469,434	$8,155,859	$0	$6,282	$4,147
General Plant Assigned to Line Transformers - NFA	$4,019,224	$1,070,645	$335,974	$1,626,773	$984,565	$0	$764	$504
Line Transformer Net Fixed Assets Including General Plant	$37,286,204	$9,917,120	$3,120,757	$15,096,206	$9,140,424	$0	$7,046	$4,651
General Expenses								
Acct 5005 - Operation Supervision and Engineering	$1,770,210	$402,772	$126,768	$625,497	$483,482	$131,003	$454	$233
Acct 5010 - Load Dispatching	$1,742,955	$396,571	$124,817	$615,867	$476,038	$128,986	$447	$230
Acct 5085 - Miscellaneous Distribution Expense	$1,796,741	$408,809	$128,668	$634,872	$490,728	$132,967	$461	$237
Acct 5105 - Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0
Total	$5,309,907	$1,208,152	$380,253	$1,876,236	$1,450,248	$392,956	$1,362	$700
Acct 1850 - Line Transformers - Gross Assets	$37,229,794	$9,900,280	$3,116,510	$15,073,933	$9,127,398	$0	$7,031	$4,642
Acct 1815 - 1855	$308,674,253	$70,231,982	$22,104,796	$109,068,894	$84,305,461	$22,843,239	$79,169	$40,713

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O2.2 Primary Cost PLCC Adjustment Worksheet - Run 2

Primary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

		1	2	4	5	6	7	9
Description	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$1,331,337	$280,994	$88,432	$440,995	$379,579	$140,778	$380	$180
Depreciation on Acct 1835-4 Primary Overhead Conductors	$426,880	$90,098	$28,355	$141,401	$121,708	$45,139	$122	$58
Depreciation on Acct 1840-4 Primary Underground Conduit	$470,806	$99,369	$31,273	$155,950	$134,232	$49,784	$134	$64
Depreciation on Acct 1845-4 Primary Underground Conductors	$3,566,856	$752,826	$236,924	$1,181,492	$1,016,949	$377,165	$1,018	$481
Depreciation on General Plant Assigned to Primary C&P	$2,453,627	$518,926	$162,802	$812,726	$699,213	$258,922	$705	$333
Primary C&P Operations and Maintenance	$3,199,969	$675,901	$212,715	$1,060,674	$912,113	$337,221	$913	$432
Allocation of General Expenses	$2,697,244	$569,285	$179,161	$893,440	$769,013	$285,211	$770	$364
Admin and General Assigned to Primary C&P	$2,460,306	$505,994	$157,647	$812,289	$716,750	$266,607	$692	$326
PILs on Primary C&P	$907,308	$191,498	$60,267	$300,538	$258,683	$95,940	$259	$122
Debt Return on Primary C&P	$5,598,768	$1,181,685	$371,891	$1,854,546	$1,596,269	$592,023	$1,598	$756
Equity Return on Primary C&P	$6,960,456	$1,469,085	$462,339	$2,305,594	$1,984,501	$736,010	$1,987	$940
Total	**$30,073,556**	**$6,335,661**	**$1,991,805**	**$9,959,645**	**$8,589,011**	**$3,184,799**	**$8,579**	**$4,056**
Primary NCP	4,899,316	1,034,057	325,431	1,622,859	1,396,848	518,061	1,399	661
PLCC Amount	340,362	282,984	28,186	6,317	742	14	17,411	4,707
Adjustment to Customer Related Cost for PLCC	**$2,085,434**	**$1,733,841**	**$172,510**	**$38,767**	**$4,565**	**$89**	**$106,796**	**$28,867**
General Plant - Gross Assets	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
General Plant - Accumulated Depreciation	($16,303,974)	($6,455,522)	($1,473,999)	($4,135,638)	($3,097,635)	($878,711)	($205,438)	($57,031)
General Plant - Net Fixed Assets	$56,028,557	$22,184,382	$5,065,392	$14,212,109	$10,645,013	$3,019,688	$705,985	$195,987
General Plant - Depreciation	$8,066,349	$3,193,853	$729,257	$2,046,096	$1,532,547	$434,740	$101,640	$28,216
Total Net Fixed Assets Excluding General Plant	**$463,618,704**	**$183,304,012**	**$41,985,446**	**$117,674,141**	**$88,180,268**	**$25,052,998**	**$5,808,653**	**$1,613,186**
Total Administration and General Expense	**$26,231,495**	**$13,005,981**	**$4,066,162**	**$5,240,218**	**$2,780,657**	**$739,907**	**$306,432**	**$92,139**
Total O&M	**$34,702,741**	**$17,373,250**	**$5,486,517**	**$6,842,586**	**$3,538,576**	**$935,881**	**$403,982**	**$121,949**
Primary Conductors and Poles Gross Assets								
Acct 1830-4 Primary Poles, Towers & Fixtures	$45,644,657	$9,633,833	$3,031,888	$15,119,420	$13,013,785	$4,826,538	$13,031	$6,162
Acct 1835-4 Primary Overhead Conductors	$8,071,196	$1,703,519	$536,119	$2,673,518	$2,301,185	$853,461	$2,304	$1,090
Acct 1840-4 Primary Underground Conduit	$19,273,140	$4,067,819	$1,280,194	$6,384,070	$5,494,980	$2,037,972	$5,502	$2,602
Acct 1845-4 Primary Underground Conductors	$83,806,568	$17,688,346	$5,566,744	$27,760,242	$23,894,158	$8,861,840	$23,925	$11,313
Subtotal	*$156,795,560*	*$33,093,517*	*$10,414,944*	*$51,937,251*	*$44,704,109*	*$16,579,811*	*$44,762*	*$21,166*

		1	2	4	5	6	7	9
Description	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
Primary Conductors and Poles Accumulated Depreciation								
Acct 1830-4 Primary Poles, Towers & Fixtures	($3,948,144)	($833,301)	($262,250)	($1,307,790)	($1,125,658)	($417,483)	($1,127)	($533)
Acct 1835-4 Primary Overhead Conductors	($767,176)	($161,921)	($50,959)	($254,121)	($218,730)	($81,122)	($219)	($104)
Acct 1840-4 Primary Underground Conduit	($1,560,827)	($329,431)	($103,676)	($517,011)	($445,009)	($165,044)	($446)	($211)
Acct 1845-4 Primary Underground Conductors	($9,410,767)	($1,986,251)	($625,098)	($3,117,240)	($2,683,111)	($995,109)	($2,687)	($1,270)
Subtotal	***($15,686,913)***	***($3,310,904)***	***($1,041,983)***	***($5,196,162)***	***($4,472,508)***	***($1,658,759)***	***($4,478)***	***($2,118)***
Primary Conductor & Pools - Net Fixed Assets	$141,108,647	$29,782,612	$9,372,961	$46,741,089	$40,231,600	$14,921,052	$40,284	$19,049
General Plant Assigned to Primary C&P - NFA	$17,042,802	$3,604,443	$1,130,814	$5,645,161	$4,856,709	$1,798,465	$4,896	$2,314
Primary C&P Net Fixed Assets Including General Plant	$158,151,449	$33,387,055	$10,503,775	$52,386,250	$45,088,309	$16,719,517	$45,180	$21,363
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-5 Secondary Poles, Towers & Fixtures	$17,891,892	$4,757,876	$1,497,732	$7,244,230	$4,386,444	$0	$3,379	$2,231
Acct 1835-5 Secondary Overhead Conductors	$3,163,765	$841,320	$264,839	$1,280,974	$775,641	$0	$597	$394
Acct 1840-5 Secondary Underground Conduit	$6,424,380	$1,708,394	$537,786	$2,601,161	$1,575,025	$0	$1,213	$801
Acct 1845-5 Secondary Underground Conductors	$27,935,523	$7,428,714	$2,338,486	$11,310,785	$6,848,779	$0	$5,276	$3,483
Subtotal	***$55,415,560***	***$14,736,304***	***$4,638,843***	***$22,437,150***	***$13,585,889***	***$0***	***$10,465***	***$6,909***
Operations and Maintenance								
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$989,913	$224,226	$70,572	$348,430	$271,099	$75,198	$256	$131
Acct 5025 Overhead Distribution Lines & Feeders - Other	$216,977	$49,148	$15,469	$76,372	$59,422	$16,483	$56	$29
Acct 5040 Underground Distribution Lines & Feeders - Labour	$2,248,113	$505,324	$159,043	$786,061	$618,510	$178,289	$587	$298
Acct 5045 Underground Distribution Lines & Feeders - Other	$200,816	$45,139	$14,207	$70,216	$55,249	$15,926	$52	$27
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$675,636	$153,039	$48,167	$237,811	$185,031	$51,325	$174	$89
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$4,331,454**	**$976,875**	**$307,458**	**$1,518,890**	**$1,189,311**	**$337,221**	**$1,126**	**$573**
General Expenses								
Acct 5005 - Operation Supervision and Engineering	$1,770,210	$402,772	$126,768	$625,497	$483,482	$131,003	$454	$233
Acct 5010 - Load Dispatching	$1,742,955	$396,571	$124,817	$615,867	$476,038	$128,986	$447	$230
Acct 5085 - Miscellaneous Distribution Expense	$1,796,741	$408,809	$128,668	$634,872	$490,728	$132,967	$461	$237
Acct 5105 - Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$5,309,907**	**$1,208,152**	**$380,253**	**$1,876,236**	**$1,450,248**	**$392,956**	**$1,362**	**$700**
Primary Conductors and Poles Gross Assets	$156,795,560	$33,093,517	$10,414,944	$51,937,251	$44,704,109	$16,579,811	$44,762	$21,166
Acct 1815 - 1855	$308,674,253	$70,231,982	$22,104,796	$109,068,894	$84,305,461	$22,843,239	$79,169	$40,713

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O2.3 Secondary Cost PLCC Adjustment Worksheet - Run 2

Secondary Conductors and Poles Cost Pool Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Allocation by Rate Classification

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$521,860	$138,775	$43,685	$211,296	$127,941	$0	$99	$65
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$239,042	$104,254	$19,912	$69,030	$41,122	$0	$3,708	$1,015
Depreciation on Acct 1840-5 Secondary Underground Conduit	$224,193	$97,778	$18,676	$64,742	$38,568	$0	$3,478	$952
Depreciation on Acct 1845-5 Secondary Underground Conductors	$1,698,503	$740,772	$141,487	$490,490	$292,194	$0	$26,349	$7,211
Depreciation on General Plant Assigned to Secondary C&P	$868,129	$231,253	$72,568	$351,373	$212,660	$0	$165	$109
Secondary C&P Operations and Maintenance	$1,131,486	$300,974	$94,744	$458,216	$277,198	$0	$213	$141
Allocation of General Expenses	$953,275	$253,498	$79,799	$385,971	$233,709	$0	$180	$119
Admin and General Assigned to Primary C&P	$864,539	$225,315	$70,216	$350,913	$217,825	$0	$162	$107
PILs on Secondary C&P	$320,914	$85,339	$26,864	$129,935	$78,677	$0	$61	$40
Debt Return on Secondary C&P	$1,980,281	$526,603	$165,770	$801,794	$485,493	$0	$374	$247
Equity Return on Secondary C&P	$2,461,909	$654,680	$206,087	$996,800	$603,571	$0	$465	$307
Total	**$11,264,131**	**$3,359,242**	**$939,807**	**$4,310,559**	**$2,608,958**	**$0**	**$35,253**	**$10,312**
Secondary NCP	3,704,481	985,109	310,103	1,499,904	908,205	0	700	462
PLCC Amount	340,347	282,984	28,186	6,317	742	0	17,411	4,707
Adjustment to Customer Related Cost for PLCC	**$2,053,157**	**$964,981**	**$85,420**	**$18,154**	**$2,133**	**$0**	**$877,369**	**$105,100**
General Plant - Gross Assets	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
General Plant - Accumulated Depreciation	($16,303,974)	($6,455,522)	($1,473,999)	($4,135,638)	($3,097,635)	($878,711)	($205,438)	($57,031)
General Plant - Net Fixed Assets	$56,028,557	$22,184,382	$5,065,392	$14,212,109	$10,645,013	$3,019,688	$705,985	$195,987
General Plant - Depreciation	$8,066,349	$3,193,853	$729,257	$2,046,096	$1,532,547	$434,740	$101,640	$28,216
Total Net Fixed Assets Excluding General Plant	$463,618,704	$183,304,012	$41,985,446	$117,674,141	$88,180,268	$25,052,998	$5,808,653	$1,613,186
Total Administration and General Expense	$26,231,495	$13,005,981	$4,066,162	$5,240,218	$2,780,657	$739,907	$306,432	$92,139
Total O&M	$34,702,741	$17,373,250	$5,486,517	$6,842,586	$3,538,576	$935,881	$403,982	$121,949
Secondary Conductors and Poles Gross Plant								
Acct 1830-5 Secondary Poles, Towers & Fixtures	$17,891,892	$4,757,876	$1,497,732	$7,244,230	$4,386,444	$0	$3,379	$2,231
Acct 1835-5 Secondary Overhead Conductors	$3,163,765	$841,320	$264,839	$1,280,974	$775,641	$0	$597	$394
Acct 1840-5 Secondary Underground Conduit	$6,424,380	$1,708,394	$537,786	$2,601,161	$1,575,025	$0	$1,213	$801
Acct 1845-5 Secondary Underground Conductors	$27,935,523	$7,428,714	$2,338,486	$11,310,785	$6,848,779	$0	$5,276	$3,483
Subtotal	***$55,415,560***	***$14,736,304***	***$4,638,843***	***$22,437,150***	***$13,585,889***	***$0***	***$10,465***	***$6,909***
Secondary Conductors and Poles Accumulated Depreciation								
Acct 1830-5 Secondary Poles, Towers & Fixtures	($1,547,602)	($411,544)	($129,550)	($626,607)	($379,416)	$0	($292)	($193)
Acct 1835-5 Secondary Overhead Conductors	($300,719)	($79,968)	($25,173)	($121,758)	($73,725)	$0	($57)	($37)
Acct 1840-5 Secondary Underground Conduit	($520,276)	($138,354)	($43,552)	($210,654)	($127,553)	$0	($98)	($65)
Acct 1845-5 Secondary Underground Conductors	($3,136,922)	($834,182)	($262,592)	($1,270,105)	($769,060)	$0	($592)	($391)

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Subtotal	***($5,505,519)***	***($1,464,047)***	***($460,868)***	***($2,229,124)***	***($1,349,754)***	***$0***	***($1,040)***	***($686)***
Secondary Conductor & Pools - Net Fixed Assets	$49,910,041	$13,272,257	$4,177,975	$20,208,026	$12,236,135	$0	$9,426	$6,222
General Plant Assigned to Secondary C&P - NFA	$6,029,993	$1,606,276	$504,058	$2,440,627	$1,477,131	$0	$1,146	$756
Secondary C&P Net Fixed Assets Including General Plant	$55,940,034	$14,878,532	$4,682,033	$22,648,652	$13,713,266	$0	$10,571	$6,978
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$45,644,657	$9,633,833	$3,031,888	$15,119,420	$13,013,785	$4,826,538	$13,031	$6,162
Acct 1835-4 Primary Overhead Conductors	$8,071,196	$1,703,519	$536,119	$2,673,518	$2,301,185	$853,461	$2,304	$1,090
Acct 1840-4 Primary Underground Conduit	$19,273,140	$4,067,819	$1,280,194	$6,384,070	$5,494,980	$2,037,972	$5,502	$2,602
Acct 1845-4 Primary Underground Conductors	$83,806,568	$17,688,346	$5,566,744	$27,760,242	$23,894,158	$8,861,840	$23,925	$11,313
Subtotal	***$156,795,560***	***$33,093,517***	***$10,414,944***	***$51,937,251***	***$44,704,109***	***$16,579,811***	***$44,762***	***$21,166***
Operations and Maintenance								
Acct 5020 Overhead Distribution Lines & Feeders - Labour	$989,913	$224,226	$70,572	$348,430	$271,099	$75,198	$256	$131
Acct 5025 Overhead Distribution Lines & Feeders - Other	$216,977	$49,148	$15,469	$76,372	$59,422	$16,483	$56	$29
Acct 5040 Underground Distribution Lines & Feeders - Labour	$2,248,113	$505,324	$159,043	$786,061	$618,510	$178,289	$587	$298
Acct 5045 Underground Distribution Lines & Feeders - Other	$200,816	$45,139	$14,207	$70,216	$55,249	$15,926	$52	$27
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5120 Maintenance of Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5125 Maintenance of Overhead Conductors & Devices	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way	$675,636	$153,039	$48,167	$237,811	$185,031	$51,325	$174	$89
Acct 5145 Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5150 Maintenance of Underground Conductors & Devices	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$4,331,454**	**$976,875**	**$307,458**	**$1,518,890**	**$1,189,311**	**$337,221**	**$1,126**	**$573**
General Expenses								
Acct 5005 - Operation Supervision and Engineering	$1,770,210	$402,772	$126,768	$625,497	$483,482	$131,003	$454	$233
Acct 5010 - Load Dispatching	$1,742,955	$396,571	$124,817	$615,867	$476,038	$128,986	$447	$230
Acct 5085 - Miscellaneous Distribution Expense	$1,796,741	$408,809	$128,668	$634,872	$490,728	$132,967	$461	$237
Acct 5105 - Maintenance Supervision and Engineering	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$5,309,907**	**$1,208,152**	**$380,253**	**$1,876,236**	**$1,450,248**	**$392,956**	**$1,362**	**$700**
Secondary Conductors and Poles Gross Assets	$55,415,560	$14,736,304	$4,638,843	$22,437,150	$13,585,889	$0	$10,465	$6,909
Acct 1815 - 1855	$308,674,253	$70,231,982	$22,104,796	$109,068,894	$84,305,461	$22,843,239	$79,169	$40,713

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O3.1 Line Transformers Unit Cost Worksheet - Run 2

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Depreciation on Acct 1850 Line Transformers	$2,630,107	$1,221,686	$218,911	$708,619	$420,400	$0	$47,518	$12,973
Depreciation on General Plant Assigned to Line Transformers	$890,746	$414,218	$73,991	$239,764	$142,178	$0	$16,180	$4,415
Acct 5035 - Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5055 - Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5160 - Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$985,508	$457,842	$82,026	$265,471	$157,492	$0	$17,813	$4,863
Admin and General Assigned to Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0
PILs on Line Transformers	$329,080	$152,858	$27,390	$88,663	$52,601	$0	$5,946	$1,623
Debt Return on Line Transformers	$2,030,668	$943,246	$169,018	$547,114	$324,585	$0	$36,688	$10,016
Equity Return on Line Transformers	$2,524,550	$1,172,655	$210,125	$680,179	$403,527	$0	$45,611	$12,452
Total	**$9,390,658**	**$4,362,506**	**$781,462**	**$2,529,811**	**$1,500,782**	**$0**	**$169,756**	**$46,342**
Billed kW without Line Transformer Allowance		0	0	5,717,360	2,321,363	0	49,889	0
Billed kWh without Line Transformer Allowance		1,423,857,475	612,188,101	2,139,657,427	2,249,538,514	997,124,443	19,019,721	10,383,027
Line Transformation Unit Cost ($/kW)		**$0.0000**	**$0.0000**	**$0.4425**	**$0.6465**	**$0.0000**	**$3.4027**	**$0.0000**
Line Transformation Unit Cost ($/kWh)		**$0.0031**	**$0.0013**	**$0.0012**	**$0.0007**	**$0.0000**	**$0.0089**	**$0.0045**
General Plant - Gross Assets	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
General Plant - Accumulated Depreciation	($16,303,974)	($6,455,522)	($1,473,999)	($4,135,638)	($3,097,635)	($878,711)	($205,438)	($57,031)
General Plant - Net Fixed Assets	$56,028,557	$22,184,382	$5,065,392	$14,212,109	$10,645,013	$3,019,688	$705,985	$195,987
General Plant - Depreciation	$8,066,349	$3,193,853	$729,257	$2,046,096	$1,532,547	$434,740	$101,640	$28,216
Total Net Fixed Assets Excluding General Plant	$463,618,704	$183,304,012	$41,985,446	$117,674,141	$88,180,268	$25,052,998	$5,808,653	$1,613,186
Total Administration and General Expense	$26,231,495	$13,005,981	$4,066,162	$5,240,218	$2,780,657	$739,907	$306,432	$92,139
Total O&M	$34,702,741	$17,373,250	$5,486,517	$6,842,586	$3,538,576	$935,881	$403,982	$121,949
Line Transformer Rate Base								
Acct 1850 - Line Transformers - Gross Assets	$57,276,606	$26,605,016	$4,767,291	$15,431,801	$9,155,166	$0	$1,034,821	$282,511
Line Transformers - Accumulated Depreciation	($6,096,637)	($2,831,891)	($507,440)	($1,642,592)	($974,494)	$0	($110,148)	($30,071)
Line Transformers - Net Fixed Assets	$51,179,969	$23,773,125	$4,259,851	$13,789,209	$8,180,672	$0	$924,673	$252,440

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
General Plant Assigned to Line Transformers - NFA	$6,187,088	$2,877,144	$513,936	$1,665,393	$987,561	$0	$112,385	$30,669
Line Transformer Net Fixed Assets Including General Plant	$57,367,057	$26,650,269	$4,773,787	$15,454,602	$9,168,232	$0	$1,037,058	$283,109
General Expenses								
Acct 5005 - Operation Supervision and Engineering								
Acct 5010 - Load Dispatching								
Acct 5085 - Miscellaneous Distribution Expense								
Acct 5105 - Maintenance Supervision and Engineering								
Total	**$7,585,581**	**$2,991,139**	**$580,905**	**$1,978,173**	**$1,488,142**	**$406,945**	**$110,105**	**$30,173**
Acct 1850 - Line Transformers - Gross Assets	$57,276,606	$26,605,016	$4,767,291	$15,431,801	$9,155,166	$0	$1,034,821	$282,511
Acct 1815 - 1855	$440,878,570	$173,813,864	$33,761,584	$114,990,888	$86,506,895	$23,655,895	$6,396,537	$1,752,907

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O3.2 Substation Transformers Unit Cost Worksheet - Run 2

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Depreciation on Acct 1820-2 Distribution Station Equipment	$1,794,940	$378,843	$119,227	$594,559	$511,757	$189,800	$512	$242
Depreciation on Acct 1825-2 Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1805-2 Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1806-2 Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on Acct 1808-2 Buildings and Fixtures < 50 KV	$1,315,706	$294,902	$84,797	$425,981	$367,582	$138,782	$2,225	$1,438
Depreciation on Acct 1810-2 Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation on General Plant Assigned to Substation Transformers	$508,241	$115,150	$32,567	$163,964	$141,475	$53,478	$973	$633
Acct 5012 - Station Buildings and Fixtures Expense	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5016 - Distributon Station Equipment - Labour	$1,544,169	$325,915	$102,569	$511,493	$440,259	$163,283	$441	$208
Acct 5017 - Distributon Station Equipment - Other	$166,820	$35,209	$11,081	$55,258	$47,562	$17,640	$48	$23
Acct 5114 - Maintenance of Distribution Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0
Allocation of General Expenses	$0	$0	$0	$0	$0	$0	$0	$0
Admin and General Assigned to SubstationTransformers	$1,315,524	$270,345	$84,228	$434,032	$383,336	$143,037	$371	$175
PILs on SubstationTransformers	$187,928	$42,494	$12,056	$60,632	$52,341	$19,815	$358	$233
Debt Return on Substation Transformers	$1,159,658	$262,217	$74,393	$374,147	$322,981	$122,276	$2,207	$1,435
Equity Return on Substation Transformers	$1,441,701	$325,992	$92,487	$465,145	$401,533	$152,015	$2,744	$1,785
Total	**$9,434,686**	**$2,051,067**	**$613,405**	**$3,085,212**	**$2,668,826**	**$1,000,126**	**$9,879**	**$6,171**
Billed kW without Substation Transformer Allowance		0	0	6,142,022	5,154,338	1,737,267	49,889	0
Billed kWh without Substation Transformer Allowance		1,423,857,475	612,188,101	2,139,657,427	2,249,538,514	997,124,443	19,019,721	10,383,027
Substation Transformation Unit Cost ($/kW)		**$0.0000**	**$0.0000**	**$0.5023**	**$0.5178**	**$0.5757**	**$0.1980**	**$0.0000**
Substation Transformation Unit Cost ($/kWh)		**$0.0014**	**$0.0010**	**$0.0014**	**$0.0012**	**$0.0010**	**$0.0005**	**$0.0006**
General Plant - Gross Assets	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
General Plant - Accumulated Depreciation	($16,303,974)	($6,455,522)	($1,473,999)	($4,135,638)	($3,097,635)	($878,711)	($205,438)	($57,031)
General Plant - Net Fixed Assets	$56,028,557	$22,184,382	$5,065,392	$14,212,109	$10,645,013	$3,019,688	$705,985	$195,987
General Plant - Depreciation	$8,066,349	$3,193,853	$729,257	$2,046,096	$1,532,547	$434,740	$101,640	$28,216
Total Net Fixed Assets Excluding General Plant	$463,618,704	$183,304,012	$41,985,446	$117,674,141	$88,180,268	$25,052,998	$5,808,653	$1,613,186
Total Administration and General Expense	$26,231,495	$13,005,981	$4,066,162	$5,240,218	$2,780,657	$739,907	$306,432	$92,139

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O3.3 Primary Conductors and Poles Cost Pool Worksheet - Run 2

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Depreciation on Acct 1830-4 Primary Poles, Towers & Fixtures	$1,901,910	$755,381	$135,682	$451,584	$380,823	$140,802	$29,568	$8,071
Depreciation on Acct 1835-4 Primary Overhead Conductors	$609,829	$242,206	$43,505	$144,796	$122,107	$45,147	$9,481	$2,588
Depreciation on Acct 1840-4 Primary Underground Conduit	$672,579	$267,128	$47,982	$159,695	$134,672	$49,792	$10,456	$2,854
Depreciation on Acct 1845-4 Primary Underground Conductors	$5,095,509	$2,023,781	$363,513	$1,209,862	$1,020,284	$377,230	$79,216	$21,623
Depreciation on General Plant Assigned to Primary C&P	$3,507,300	$1,395,001	$249,787	$832,241	$701,506	$258,967	$54,837	$14,962
Primary C&P Operations and Maintenance	$4,571,575	$1,816,291	$326,298	$1,086,127	$915,102	$337,279	$71,076	$19,401
Allocation of General Expenses	$3,853,948	$1,530,960	$274,948	$914,924	$771,547	$285,266	$59,941	$16,361
Admin and General Assigned to Primary C&P	$3,487,645	$1,359,714	$241,826	$831,783	$719,098	$266,652	$53,913	$14,658
PILs on Primary C&P	$1,296,154	$514,793	$92,467	$307,755	$259,531	$95,957	$20,150	$5,500
Debt Return on Primary C&P	$7,998,240	$3,176,658	$570,593	$1,899,078	$1,601,503	$592,124	$124,343	$33,940
Equity Return on Primary C&P	$9,943,508	$3,949,260	$709,368	$2,360,957	$1,991,008	$736,136	$154,585	$42,195
Total	**$42,938,196**	**$17,031,173**	**$3,055,969**	**$10,198,803**	**$8,617,182**	**$3,185,351**	**$667,565**	**$182,154**
General Plant - Gross Assets	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
General Plant - Accumulated Depreciation	($16,303,974)	($6,455,522)	($1,473,999)	($4,135,638)	($3,097,635)	($878,711)	($205,438)	($57,031)
General Plant - Net Fixed Assets	$56,028,557	$22,184,382	$5,065,392	$14,212,109	$10,645,013	$3,019,688	$705,985	$195,987
General Plant - Depreciation	$8,066,349	$3,193,853	$729,257	$2,046,096	$1,532,547	$434,740	$101,640	$28,216
Total Net Fixed Assets Excluding General Plant	$463,618,704	$183,304,012	$41,985,446	$117,674,141	$88,180,268	$25,052,998	$5,808,653	$1,613,186
Total Administration and General Expense	$26,231,495	$13,005,981	$4,066,162	$5,240,218	$2,780,657	$739,907	$306,432	$92,139
Total O&M	$34,702,741	$17,373,250	$5,486,517	$6,842,586	$3,538,576	$935,881	$403,982	$121,949
Primary Conductors and Poles Gross Assets								
Acct 1830-4 Primary Poles, Towers & Fixtures	$65,206,653	$25,898,103	$4,651,832	$15,482,473	$13,056,454	$4,827,366	$1,013,721	$276,704
Acct 1835-4 Primary Overhead Conductors	$11,530,279	$4,579,477	$822,568	$2,737,715	$2,308,730	$853,607	$179,253	$48,929
Acct 1840-4 Primary Underground Conduit	$27,533,057	$10,935,294	$1,964,204	$6,537,367	$5,512,997	$2,038,322	$428,036	$116,836
Acct 1845-4 Primary Underground Conductors	$119,723,668	$47,550,607	$8,541,066	$28,426,831	$23,972,501	$8,863,359	$1,861,257	$508,047
Subtotal	**$223,993,657**	**$88,963,482**	**$15,979,670**	**$53,184,386**	**$44,850,682**	**$16,582,654**	**$3,482,267**	**$950,516**
Primary Conductors and Poles Accumulated Depreciation								
Acct 1830-4 Primary Poles, Towers & Fixtures	($5,640,205)	($2,240,118)	($402,371)	($1,339,194)	($1,129,349)	($417,555)	($87,684)	($23,934)
Acct 1835-4 Primary Overhead Conductors	($1,095,965)	($435,284)	($78,186)	($260,223)	($219,447)	($81,136)	($17,038)	($4,651)

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Acct 1840-4 Primary Underground Conduit	($2,229,753)	($885,590)	($159,070)	($529,426)	($446,468)	($165,073)	($34,664)	($9,462)
Acct 1845-4 Primary Underground Conductors	($13,443,952)	($5,339,530)	($959,089)	($3,192,092)	($2,691,908)	($995,280)	($209,003)	($57,049)
Subtotal	**($22,409,876)**	**($8,900,522)**	**($1,598,717)**	**($5,320,934)**	**($4,487,173)**	**($1,659,044)**	**($348,390)**	**($95,096)**
Primary Conductor & Pools - Net Fixed Assets	$201,583,782	$80,062,959	$14,380,953	$47,863,452	$40,363,509	$14,923,611	$3,133,877	$855,420
General Plant Assigned to Primary C&P - NFA	$24,361,574	$9,689,626	$1,735,010	$5,780,714	$4,872,633	$1,798,773	$380,892	$103,925
Primary C&P Net Fixed Assets Including General Plant	$225,945,356	$89,752,585	$16,115,963	$53,644,167	$45,236,142	$16,722,384	$3,514,769	$959,345
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Acct 1830-5 Secondary Poles, Towers & Fixtures	$25,559,846	$11,147,478	$2,129,160	$7,381,115	$4,397,066	$0	$396,511	$108,516
Acct 1835-5 Secondary Overhead Conductors	$4,519,664	$1,971,172	$376,492	$1,305,179	$777,519	$0	$70,114	$19,189
Acct 1840-5 Secondary Underground Conduit	$9,177,686	$4,002,686	$764,510	$2,650,312	$1,578,839	$0	$142,374	$38,965
Acct 1845-5 Secondary Underground Conductors	$39,907,889	$17,405,125	$3,324,366	$11,524,511	$6,865,363	$0	$619,093	$169,432
Subtotal	**$79,165,085**	**$34,526,461**	**$6,594,529**	**$22,861,116**	**$13,618,786**	**$0**	**$1,228,092**	**$336,101**
Operations and Maintenance								
Acct 5020 Overhead Distribution Lines & Feeders - Labour								
Acct 5025 Overhead Distribution Lines & Feeders - Other								
Acct 5040 Underground Distribution Lines & Feeders - Labour								
Acct 5045 Underground Distribution Lines & Feeders - Other								
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid								
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid								
Acct 5120 Maintenance of Poles, Towers & Fixtures								
Acct 5125 Maintenance of Overhead Conductors & Devices								
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way								
Acct 5145 Maintenance of Underground Conduit								
Acct 5150 Maintenance of Underground Conductors & Devices								
Total	**$6,187,792**	**$2,521,188**	**$460,956**	**$1,552,995**	**$1,192,970**	**$337,279**	**$96,143**	**$26,261**
General Expenses								
Acct 5005 - Operation Supervision and Engineering								
Acct 5010 - Load Dispatching								
Acct 5085 - Miscellaneous Distribution Expense								
Acct 5105 - Maintenance Supervision and Engineering								
Total	**$7,585,581**	**$2,991,139**	**$580,905**	**$1,978,173**	**$1,488,142**	**$406,945**	**$110,105**	**$30,173**
Primary Conductors and Poles Gross Assets	$223,993,657	$88,963,482	$15,979,670	$53,184,386	$44,850,682	$16,582,654	$3,482,267	$950,516
Acct 1815 - 1855	$440,878,570	$173,813,864	$33,761,584	$114,990,888	$86,506,895	$23,655,895	$6,396,537	$1,752,907

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Grouping of Operation and Maintenance	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ 2,689,322	$ 1,097,624	$ 200,914	$ 677,426	$ 517,131	$ 143,030	$ 41,784	$ 11,414
1840 & 1845	$ 3,498,470	$ 1,423,564	$ 260,042	$ 875,570	$ 675,840	$ 194,249	$ 54,359	$ 14,848
Total	**$ 6,187,792**	**$ 2,521,188**	**$ 460,956**	**$ 1,552,995**	**$ 1,192,970**	**$ 337,279**	**$ 96,143**	**$ 26,261**

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O3.4 Secondary Cost Pool Worksheet - Run 2

ALLOCATION BY RATE CLASSIFICATION

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Depreciation on Acct 1830-5 Secondary Poles, Towers & Fixtures	$745,515	$325,143	$62,102	$215,288	$128,251	$0	$11,565	$3,165
Depreciation on Acct 1835-5 Secondary Overhead Conductors	$239,042	$104,254	$19,912	$69,030	$41,122	$0	$3,708	$1,015
Depreciation on Acct 1840-5 Secondary Underground Conduit	$224,193	$97,778	$18,676	$64,742	$38,568	$0	$3,478	$952
Depreciation on Acct 1845-5 Secondary Underground Conductors	$1,698,503	$740,772	$141,487	$490,490	$292,194	$0	$26,349	$7,211
Depreciation on General Plant Assigned to Secondary C&P	$1,240,815	$541,815	$103,162	$358,013	$213,175	$0	$19,354	$5,295
Secondary C&P Operations and Maintenance	$1,616,217	$704,897	$134,658	$466,868	$277,868	$0	$25,067	$6,860
Allocation of General Expenses	$1,362,107	$594,161	$113,466	$393,277	$234,278	$0	$21,139	$5,785
Admin and General Assigned to Primary C&P	$1,227,586	$527,701	$99,797	$357,539	$218,352	$0	$19,014	$5,183
PILs on Secondary C&P	$458,449	$199,944	$38,189	$132,390	$78,867	$0	$7,112	$1,946
Debt Return on Secondary C&P	$2,828,973	$1,233,807	$235,656	$816,944	$486,669	$0	$43,886	$12,011
Equity Return on Secondary C&P	$3,517,013	$1,533,883	$292,971	$1,015,635	$605,032	$0	$54,560	$14,932
Total	**$15,158,412**	**$6,604,156**	**$1,260,076**	**$4,380,216**	**$2,614,378**	**$0**	**$235,232**	**$64,355**
General Plant - Gross Assets	$72,332,531	$28,639,905	$6,539,391	$18,347,747	$13,742,648	$3,898,400	$911,423	$253,018
General Plant - Accumulated Depreciation	($16,303,974)	($6,455,522)	($1,473,999)	($4,135,638)	($3,097,635)	($878,711)	($205,438)	($57,031)
General Plant - Net Fixed Assets	$56,028,557	$22,184,382	$5,065,392	$14,212,109	$10,645,013	$3,019,688	$705,985	$195,987
General Plant - Depreciation	$8,066,349	$3,193,853	$729,257	$2,046,096	$1,532,547	$434,740	$101,640	$28,216
Total Net Fixed Assets Excluding General Plant	**$463,618,704**	**$183,304,012**	**$41,985,446**	**$117,674,141**	**$88,180,268**	**$25,052,998**	**$5,808,653**	**$1,613,186**
Total Administration and General Expense	**$26,231,495**	**$13,005,981**	**$4,066,162**	**$5,240,218**	**$2,780,657**	**$739,907**	**$306,432**	**$92,139**
Total O&M	**$34,702,741**	**$17,373,250**	**$5,486,517**	**$6,842,586**	**$3,538,576**	**$935,881**	**$403,982**	**$121,949**
Secondary Conductors and Poles Gross Plant								
Acct 1830-5 Secondary Poles, Towers & Fixtures	$25,559,846	$11,147,478	$2,129,160	$7,381,115	$4,397,066	$0	$396,511	$108,516
Acct 1835-5 Secondary Overhead Conductors	$4,519,664	$1,971,172	$376,492	$1,305,179	$777,519	$0	$70,114	$19,189
Acct 1840-5 Secondary Underground Conduit	$9,177,686	$4,002,686	$764,510	$2,650,312	$1,578,839	$0	$142,374	$38,965
Acct 1845-5 Secondary Underground Conductors	$39,907,889	$17,405,125	$3,324,366	$11,524,511	$6,865,363	$0	$619,093	$169,432
Subtotal	***$79,165,085***	***$34,526,461***	***$6,594,529***	***$22,861,116***	***$13,618,786***	***$0***	***$1,228,092***	***$336,101***
Secondary Conductors and Poles Accumulated Depreciation								
Acct 1830-5 Secondary Poles, Towers & Fixtures	($2,210,860)	($964,228)	($184,167)	($638,447)	($380,335)	$0	($34,297)	($9,386)
Acct 1835-5 Secondary Overhead Conductors	($429,599)	($187,362)	($35,786)	($124,059)	($73,904)	$0	($6,664)	($1,824)
Acct 1840-5 Secondary Underground Conduit	($743,251)	($324,156)	($61,914)	($214,634)	($127,862)	$0	($11,530)	($3,156)
Acct 1845-5 Secondary Underground Conductors	($4,481,317)	($1,954,448)	($373,298)	($1,294,105)	($770,922)	$0	($69,519)	($19,026)
Subtotal	***($7,865,027)***	***($3,430,193)***	***($655,164)***	***($2,271,245)***	***($1,353,022)***	***$0***	***($122,011)***	***($33,392)***
Secondary Conductor & Pools - Net Fixed Assets	$71,300,058	$31,096,267	$5,939,364	$20,589,872	$12,265,764	$0	$1,106,081	$302,710
General Plant Assigned to Secondary C&P - NFA	$8,618,653	$3,763,428	$716,563	$2,486,744	$1,480,708	$0	$134,433	$36,776
Secondary C&P Net Fixed Assets Including General Plant	$79,918,711	$34,859,696	$6,655,927	$23,076,616	$13,746,472	$0	$1,240,515	$339,486

Description	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Acct 1830-3 Bulk Poles, Towers & Fixtures	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1835-3 Bulk Overhead Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1840-3 Bulk Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0
Acct 1845-3 Bulk Underground Conductors	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
Acct 1830-4 Primary Poles, Towers & Fixtures	$65,206,653	$25,898,103	$4,651,832	$15,482,473	$13,056,454	$4,827,366	$1,013,721	$276,704
Acct 1835-4 Primary Overhead Conductors	$11,530,279	$4,579,477	$822,568	$2,737,715	$2,308,730	$853,607	$179,253	$48,929
Acct 1840-4 Primary Underground Conduit	$27,533,057	$10,935,294	$1,964,204	$6,537,367	$5,512,997	$2,038,322	$428,036	$116,836
Acct 1845-4 Primary Underground Conductors	$119,723,668	$47,550,607	$8,541,066	$28,426,831	$23,972,501	$8,863,359	$1,861,257	$508,047
Subtotal	***$223,993,657***	***$88,963,482***	***$15,979,670***	***$53,184,386***	***$44,850,682***	***$16,582,654***	***$3,482,267***	***$950,516***
Operations and Maintenance								
Acct 5020 Overhead Distribution Lines & Feeders - Labour								
Acct 5025 Overhead Distribution Lines & Feeders - Other								
Acct 5040 Underground Distribution Lines & Feeders - Labour								
Acct 5045 Underground Distribution Lines & Feeders - Other								
Acct 5090 Underground Distribution Lines & Feeders - Rental Paid								
Acct 5095 Overhead Distribution Lines & Feeders - Rental Paid								
Acct 5120 Maintenance of Poles, Towers & Fixtures								
Acct 5125 Maintenance of Overhead Conductors & Devices								
Acct 5135 Overhead Distribution Lines & Feeders - Right of Way								
Acct 5145 Maintenance of Underground Conduit								
Acct 5150 Maintenance of Underground Conductors & Devices								
Total	**$6,187,792**	**$2,521,188**	**$460,956**	**$1,552,995**	**$1,192,970**	**$337,279**	**$96,143**	**$26,261**
General Expenses								
Acct 5005 - Operation Supervision and Engineering								
Acct 5010 - Load Dispatching								
Acct 5085 - Miscellaneous Distribution Expense								
Acct 5105 - Maintenance Supervision and Engineering								
Total	**$7,585,581**	**$2,991,139**	**$580,905**	**$1,978,173**	**$1,488,142**	**$406,945**	**$110,105**	**$30,173**
Secondary Conductors and Poles Gross Assets	$79,165,085	$34,526,461	$6,594,529	$22,861,116	$13,618,786	$0	$1,228,092	$336,101
Acct 1815 - 1855	$440,878,570	$173,813,864	$33,761,584	$114,990,888	$86,506,895	$23,655,895	$6,396,537	$1,752,907

Grouping of Operation and Maintenance	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ 2,689,322	$ 1,097,624	$ 200,914	$ 677,426	$ 517,131	$ 143,030	$ 41,784	$ 11,414
1840 & 1845	$ 3,498,470	$ 1,423,564	$ 260,042	$ 875,570	$ 675,840	$ 194,249	$ 54,359	$ 14,848
Total	**$ 6,187,792**	**$ 2,521,188**	**$ 460,956**	**$ 1,552,995**	**$ 1,192,970**	**$ 337,279**	**$ 96,143**	**$ 26,261**

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O3.5 USL Metering Credit Worksheet - Run 2

ALLOCATION BY RATE CLASSIFICATION

Description	GS < 50kW
Depreciation on Acct 1860 Metering	$890,837
Depreciation on General Plant Assigned to Metering	$162,331
Acct 5065 - Meter expense	$295,367
Acct 5070 & 5075 - Customer Premises	$142,785
Acct 5175 - Meter Maintenance	$528,754
Acct 5310 - Meter Reading	$2,586
Admin and General Assigned to Metering	$718,508
PILs on Metering	$60,093
Debt Return on Metering	$370,816
Equity Return on Metering	$461,003
Total	$3,633,079
Number of Customers	17,703
Metering Unit Cost ($/Customer/Month)	**$17.10**
General Plant - Gross Assets	$6,539,391
General Plant - Accumulated Depreciation	($1,473,999)
General Plant - Net Fixed Assets	$5,065,392
General Plant - Depreciation	$729,257
Total Net Fixed Assets Excluding General Plant	$41,985,446
Total Administration and General Expense	$4,066,162
Total O&M	$5,486,517
Metering Rate Base	
Acct 1860 - Metering - Gross Assets	$11,155,337
Metering - Accumulated Depreciation	($1,809,476)
Metering - Net Fixed Assets	$9,345,861
General Plant Assigned to Metering - NFA	$1,127,544
Metering Net Fixed Assets Including General Plant	$10,473,405

Ontario

2013 COST ALLOCATION

Enersource Hydro Mississauga

EB-2012-0033

Friday, April 27, 2012

Sheet O3.6 MicroFIT Charge Worksheet - Run 2

Instructions:
More Instructions provided on the first tab in this workbook.

ALLOCATION BY RATE CLASSIFICATION

Description	Residential	Monthly Unit Cost
Customer Premises - Operations Labour (5070)	$ 1,354,596.80	$ 0.64
Customer Premises - Materials and Expenses (5075)	$ 71,921.15	$ 0.03
Meter Expenses (5065)	$ 604,740.90	$ 0.28
Maintenance of Meters (5175)	$ 1,082,580.83	$ 0.51
Meter Reading Expenses (5310)	$ 13,245.41	$ 0.01
Customer Billing (5315)	$ 2,422,213.01	$ 1.14
Amortization Expense - General Plant Assigned to Meters	$ 333,402.82	$ 0.16
Admin and General Expenses allocated to O&M expenses for meters	$ 1,300,313.64	$ 0.61
Allocated PILS (general plant assigned to meters)	$ 13,282.73	$ 0.01
Interest Expense	$ 81,964.39	$ 0.04
Income Expenses	$ 101,899.12	$ 0.05
Total Cost	$ 7,380,160.81	$ 3.48
Number of Residential Customers	176865	

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O4 Summary of Allocators by Class & Accounts - Run 2

ALLOCATION BY RATE CLASSIFICATION

				1	2	4	5	6	7	9
USoA Account #	**Accounts**	**O1 Grouping**	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
1565	Conservation and Demand Management Expenditures and Recoveries	dp								
1608	Franchises and Consents	gp								
1805	Land	dp								
1805-1	Land Station >50 kV	dp								
1805-2	Land Station <50 kV	dp								
1806	Land Rights	dp								
1806-1	Land Rights Station >50 kV	dp								
1806-2	Land Rights Station <50 kV	dp								
1808	Buildings and Fixtures	dp								
1808-1	Buildings and Fixtures > 50 kV	dp								
1808-2	Buildings and Fixtures < 50 KV	dp								
1810	Leasehold Improvements	dp								
1810-1	Leasehold Improvements >50 kV	dp								
1810-2	Leasehold Improvements <50 kV	dp								
1815	Transformer Station Equipment - Normally Primary above 50 kV	dp								
1820	Distribution Station Equipment - Normally Primary below 50 kV	dp								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	dp								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	dp								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	dp								
1825	Storage Battery Equipment	dp								
1825-1	Storage Battery Equipment > 50 kV	dp								
1825-2	Storage Battery Equipment <50 kV	dp								
1830	Poles, Towers and Fixtures	dp								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	dp								
1830-4	Poles, Towers and Fixtures - Primary	dp								
1830-5	Poles, Towers and Fixtures - Secondary	dp								
1835	Overhead Conductors and Devices	dp								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	dp								
1835-4	Overhead Conductors and Devices - Primary	dp								
1835-5	Overhead Conductors and Devices - Secondary	dp								
1840	Underground Conduit	dp								
1840-3	Underground Conduit - Bulk Delivery	dp								
1840-4	Underground Conduit - Primary	dp								
1840-5	Underground Conduit - Secondary	dp								
1845	Underground Conductors and Devices	dp								
1845-3	Underground Conductors and Devices - Bulk Delivery	dp								
1845-4	Underground Conductors and Devices - Primary	dp								
1845-5	Underground Conductors and Devices - Secondary	dp								
1850	Line Transformers	dp								
1855	Services	dp								
1860	Meters	dp								
1880	IFRS Placeholder Asset Account	dp								
1905	Land	gp								
1906	Land Rights	gp								
1908	Buildings and Fixtures	gp								
1910	Leasehold Improvements	gp								

				1	2	4	5	6	7	9
USoA Account #	Accounts	O1 Grouping	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
1915	Office Furniture and Equipment	gp								
1920	Computer Equipment - Hardware	gp								
1925	Computer Software	gp								
1930	Transportation Equipment	gp								
1935	Stores Equipment	gp								
1940	Tools, Shop and Garage Equipment	gp								
1945	Measurement and Testing Equipment	gp								
1950	Power Operated Equipment	gp								
1955	Communication Equipment	gp								
1960	Miscellaneous Equipment	gp								
1970	Load Management Controls - Customer Premises	gp								
1975	Load Management Controls - Utility Premises	gp								
1980	System Supervisory Equipment	gp								
1990	Other Tangible Property	gp								
1995	Contributions and Grants - Credit	co								
2005	Property Under Capital Leases	gp								
2010	Electric Plant Purchased or Sold	gp								
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	accum dep								
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	accum dep								
3046	Balance Transferred From Income	NI								
4080	Distribution Services Revenue	CREV								
4080-1	Revenue from Rates	CREV								
4080-2	SSS Admin Charge	mi								
4082	Retail Services Revenues	mi								
4084	Service Transaction Requests (STR) Revenues	mi								
4090	Electric Services Incidental to Energy Sales	mi								
4205	Interdepartmental Rents	mi								
4210	Rent from Electric Property	mi								
4215	Other Utility Operating Income	mi								
4220	Other Electric Revenues	mi								
4225	Late Payment Charges	mi								
4235	Miscellaneous Service Revenues	mi								
4235-1	Account Set Up Charges	mi								
4235-90	Miscellaneous Service Revenues - Residual	mi								
4240	Provision for Rate Refunds	mi								
4245	Government Assistance Directly Credited to Income	mi								
4305	Regulatory Debits	mi								
4310	Regulatory Credits	mi								
4315	Revenues from Electric Plant Leased to Others	mi								
4320	Expenses of Electric Plant Leased to Others	mi								
4325	Revenues from Merchandise, Jobbing, Etc.	mi								
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	mi								
4335	Profits and Losses from Financial Instrument Hedges	mi								
4340	Profits and Losses from Financial Instrument Investments	mi								
4345	Gains from Disposition of Future Use Utility Plant	mi								
4350	Losses from Disposition of Future Use Utility Plant	mi								
4355	Gain on Disposition of Utility and Other Property	mi								
4360	Loss on Disposition of Utility and Other Property	mi								
4365	Gains from Disposition of Allowances for Emission	mi								
4370	Losses from Disposition of Allowances for Emission	mi								
4375	Revenues from Non-Utility Operations	mi								
4380	Expenses of Non-Utility Operations	mi								

				1	2	4	5	6	7	9
USoA Account #	Accounts	O1 Grouping	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
4390	Miscellaneous Non-Operating Income	mi								
4395	Rate-Payer Benefit Including Interest	mi								
4398	Foreign Exchange Gains and Losses, Including Amortization	mi								
4405	Interest and Dividend Income	mi								
4415	Equity in Earnings of Subsidiary Companies	mi								
4705	Power Purchased	cop								
4708	Charges-WMS	cop								
4710	Cost of Power Adjustments	cop								
4712	Charges-One-Time	cop								
4714	Charges-NW	cop								
4715	System Control and Load Dispatching	cop								
4716	Charges-CN	cop								
4730	Rural Rate Assistance Expense	cop								
4750	Charges-LV	cop								
5005	Operation Supervision and Engineering	di								
5010	Load Dispatching	di								
5012	Station Buildings and Fixtures Expense	di								
5014	Transformer Station Equipment - Operation Labour	di								
5015	Transformer Station Equipment - Operation Supplies and Expenses	di								
5016	Distribution Station Equipment - Operation Labour	di								
5017	Distribution Station Equipment - Operation Supplies and Expenses	di								
5020	Overhead Distribution Lines and Feeders - Operation Labour	di								
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	di								
5030	Overhead Subtransmission Feeders - Operation	di								
5035	Overhead Distribution Transformers- Operation	di								
5040	Underground Distribution Lines and Feeders - Operation Labour	di								
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	di								
5050	Underground Subtransmission Feeders - Operation	di								
5055	Underground Distribution Transformers - Operation	di								
5065	Meter Expense	cu								
5070	Customer Premises - Operation Labour	cu								
5075	Customer Premises - Materials and Expenses	cu								
5085	Miscellaneous Distribution Expense	di								
5090	Underground Distribution Lines and Feeders - Rental Paid	di								
5095	Overhead Distribution Lines and Feeders - Rental Paid	di								
5096	Other Rent	di								
5105	Maintenance Supervision and Engineering	di								
5110	Maintenance of Buildings and Fixtures - Distribution Stations	di								
5112	Maintenance of Transformer Station Equipment	di								
5114	Maintenance of Distribution Station Equipment	di								
5120	Maintenance of Poles, Towers and Fixtures	di								
5125	Maintenance of Overhead Conductors and Devices	di								
5130	Maintenance of Overhead Services	di								
5135	Overhead Distribution Lines and Feeders - Right of Way	di								
5145	Maintenance of Underground Conduit	di								
5150	Maintenance of Underground Conductors and Devices	di								
5155	Maintenance of Underground Services	di								
5160	Maintenance of Line Transformers	di								
5175	Maintenance of Meters	cu								

				1	2	4	5	6	7	9
USoA Account #	Accounts	O1 Grouping	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
5305	Supervision	cu								
5310	Meter Reading Expense	cu								
5315	Customer Billing	cu								
5320	Collecting	cu								
5325	Collecting- Cash Over and Short	cu								
5330	Collection Charges	cu								
5335	Bad Debt Expense	cu								
5340	Miscellaneous Customer Accounts Expenses	cu								
5405	Supervision	ad								
5410	Community Relations - Sundry	ad								
5415	Energy Conservation	ad								
5420	Community Safety Program	ad								
5425	Miscellaneous Customer Service and Informational Expenses	ad								
5505	Supervision	ad								
5510	Demonstrating and Selling Expense	ad								
5515	Advertising Expense	ad								
5520	Miscellaneous Sales Expense	ad								
5605	Executive Salaries and Expenses	ad								
5610	Management Salaries and Expenses	ad								
5615	General Administrative Salaries and Expenses	ad								
5620	Office Supplies and Expenses	ad								
5625	Administrative Expense Transferred Credit	ad								
5630	Outside Services Employed	ad								
5635	Property Insurance	ad								
5640	Injuries and Damages	ad								
5645	Employee Pensions and Benefits	ad								
5650	Franchise Requirements	ad								
5655	Regulatory Expenses	ad								
5660	General Advertising Expenses	ad								
5665	Miscellaneous General Expenses	ad								
5670	Rent	ad								
5675	Maintenance of General Plant	ad								
5680	Electrical Safety Authority Fees	ad								
5681	IFRS Placeholder Expense Account	ad								
5682	IFRS Placeholder Expense Account	ad								
5683	IFRS Placeholder Expense Account	ad								
5684	IFRS Placeholder Expense Account	ad								
5685	Independent Market Operator Fees and Penalties	cop								
5705	Amortization Expense - Property, Plant, and Equipment	dep								
5710	Amortization of Limited Term Electric Plant	dep								
5715	Amortization of Intangibles and Other Electric Plant	dep								
5720	Amortization of Electric Plant Acquisition Adjustments	dep								
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	dep								
5735	Amortization of Deferred Development Costs	dep								
5740	Amortization of Deferred Charges	dep								
6005	Interest on Long Term Debt	INT								
6105	Taxes Other Than Income Taxes	ad								
6110	Income Taxes	Input								
6205	Donations	ad								
6210	Life Insurance	ad								

USoA Account #	Accounts	O1 Grouping	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
6215	Penalties	ad								
6225	Other Deductions	ad								
			$1,336,476,697	$384,665,112	$118,905,259	$360,340,902	$330,912,729	$129,147,587	$9,384,771	$3,120,337
				$1,336,476,697						

Grouping by Allocator	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 1,710,989	$ 361,124	$ 113,650	$ 566,751	$ 487,821	$ 180,923	$ 488	$ 231
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 2,679,514	$ 1,778,449	$ 351,497	$ 380,999	$ 29,563	$ -	$ 109,422	$ 29,583
1860	$ 1,801,916	$ 1,082,581	$ 528,754	$ 160,283	$ 28,332	$ 1,967	$ -	$ -
1815-1855	$ 7,585,581	$ 2,991,139	$ 580,905	$ 1,978,173	$ 1,488,142	$ 406,945	$ 110,105	$ 30,173
1830 & 1835	$ 2,689,322	$ 1,097,624	$ 200,914	$ 677,426	$ 517,131	$ 143,030	$ 41,784	$ 11,414
1840 & 1845	$ 3,498,470	$ 1,423,564	$ 260,042	$ 875,570	$ 675,840	$ 194,249	$ 54,359	$ 14,848
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 3,550,000	$ 1,780,967	$ 1,082,902	$ 571,383	$ 113,117	$ -	$ -	$ 1,630
Break Out	-$ 38,575,023	-$ 15,946,154	-$ 3,746,390	-$ 9,431,481	-$ 6,915,337	-$ 1,891,812	-$ 504,780	-$ 139,069
CCA	$ 1,716,475	$ 1,426,518	$ 142,785	$ 31,859	$ 3,742	$ 73	$ 87,769	$ 23,729
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 90,831,798	$ 17,355,817	$ 7,462,141	$ 26,080,913	$ 27,420,286	$ 12,154,243	$ 231,837	$ 126,562
CEN EWMP	$ 648,500,146	$ 123,913,103	$ 53,276,489	$ 186,206,552	$ 195,769,100	$ 86,776,089	$ 1,655,217	$ 903,597
CREV	-$ 535,964	-$ 445,426	-$ 44,584	-$ 9,948	-$ 1,169	-$ 23	-$ 27,406	-$ 7,409
CWCS	$ 15,157,937	$ 10,060,640	$ 1,988,408	$ 2,155,303	$ 167,236	$ -	$ 619,000	$ 167,350
CWMC	$ 39,022,351	$ 23,444,405	$ 11,450,704	$ 3,471,086	$ 613,564	$ 42,591	$ -	$ -
CWMR	$ 24,000	$ 13,245	$ 2,586	$ 5,644	$ 2,276	$ 249	$ -	$ -
CWNB	$ 7,480,391	$ 4,279,911	$ 1,721,817	$ 1,330,018	$ 140,738	$ 1,380	-$ 2,197	$ 8,725
DCP	$ 35,768,173	$ 8,017,058	$ 2,305,246	$ 11,580,522	$ 9,992,911	$ 3,772,857	$ 60,484	$ 39,096
LPHA	-$ 1,800,000	-$ 954,017	-$ 314,540	-$ 306,248	-$ 222,111	$ -	$ -	-$ 3,083
LTNCP	$ 57,276,606	$ 26,605,016	$ 4,767,291	$ 15,431,801	$ 9,155,166	$ -	$ 1,034,821	$ 282,511
NFA	-$ 1,357,092	-$ 598,270	-$ 149,705	-$ 313,878	-$ 213,196	-$ 58,757	-$ 18,140	-$ 5,147
NFA ECC	$ 72,332,531	$ 28,639,905	$ 6,539,391	$ 18,347,747	$ 13,742,648	$ 3,898,400	$ 911,423	$ 253,018
O&M	$ 25,196,495	$ 12,614,133	$ 3,983,576	$ 4,968,172	$ 2,569,241	$ 679,512	$ 293,318	$ 88,543
PNCP	$ 283,226,996	$ 101,465,363	$ 19,914,169	$ 72,804,947	$ 61,738,747	$ 22,846,082	$ 3,499,177	$ 958,512
SNCP	$ 79,165,085	$ 34,526,461	$ 6,594,529	$ 22,861,116	$ 13,618,786	$ -	$ 1,228,092	$ 336,101
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 1,336,946,697**	**$ 384,933,154**	**$ 119,012,576**	**$ 360,424,710**	**$ 330,922,574**	**$ 129,147,996**	**$ 9,384,774**	**$ 3,120,913**

2013 COST ALLOCATION
Enersource Hydro Mississauga

EB-2012-0033
Friday, April 27, 2012
Sheet O5 Details of Allocators by Class and Account Worksheet - Run 2

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Allocation - Demand Related							Allocation - Customer Related						
					Categorization			1	2	4	5	6	7	9		1	2	4	5	6	7	9
								Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total - Demand	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
1565	Conservation and Demand Management Expenditures and Recoveries																					
1608	Franchises and Consents																					
1805	Land																					
1805-1	Land Station >50 kV																					
1805-2	Land Station <50 kV																					
1806	Land Rights																					
1806-1	Land Rights Station >50 kV																					
1806-2	Land Rights Station <50 kV																					
1808	Buildings and Fixtures																					
1808-1	Buildings and Fixtures > 50 kV																					
1808-2	Buildings and Fixtures < 50 kV																					
1810	Leasehold Improvements																					
1810-1	Leasehold Improvements >50 kV																					
1810-2	Leasehold Improvements <50 kV																					
1815	Transformer Station Equipment - Normally Primary above 50 kV																					
1820	Distribution Station Equipment - Normally Primary below 50 kV																					
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)																					
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)																					
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)																					
1825	Storage Battery Equipment																					
1825-1	Storage Battery Equipment > 50 kV																					
1825-2	Storage Battery Equipment <50 kV																					
1830	Poles, Towers and Fixtures																					
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery																					
1830-4	Poles, Towers and Fixtures - Primary																					
1830-5	Poles, Towers and Fixtures - Secondary																					
1835	Overhead Conductors and Devices																					
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery																					
1835-4	Overhead Conductors and Devices - Primary																					
1835-5	Overhead Conductors and Devices - Secondary																					
1840	Underground Conduit																					
1840-3	Underground Conduit - Bulk Delivery																					
1840-4	Underground Conduit - Primary																					
1840-5	Underground Conduit - Secondary																					
1845	Underground Conductors and Devices																					
1845-3	Underground Conductors and Devices - Bulk Delivery																					
1845-4	Underground Conductors and Devices - Primary																					
1845-5	Underground Conductors and Devices - Secondary																					
1850	Line Transformers																					
1855	Services																					
1860	Meters																					
1880	IFRS Placeholder Asset Account																					
1905	Land																					
1906	Land Rights																					
1908	Buildings and Fixtures																					
1910	Leasehold Improvements																					
1915	Office Furniture and Equipment																					
1920	Computer Equipment - Hardware																					
1925	Computer Software																					
1930	Transportation Equipment																					
1935	Stores Equipment																					
1940	Tools, Shop and Garage Equipment																					
1945	Measurement and Testing Equipment																					
1950	Power Operated Equipment																					
1955	Communication Equipment																					
1960	Miscellaneous Equipment																					
1970	Load Management Controls - Customer Premises																					
1975	Load Management Controls - Utility Premises																					
1980	System Supervisory Equipment																					
1990	Other Tangible Property																					

					Categorization			1	2	4	5	6	7	9		1	2	4	5	6	7	9
USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total - Demand	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
1995	Contributions and Grants - Credit																					
2005	Property Under Capital Leases																					
2010	Electric Plant Purchased or Sold																					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment																					
2120	Accumulated Amortization of Electric Utility Plant - Intangibles																					
3046	Balance Transferred From Income																					
4080	Distribution Services Revenue																					
4080-1	Revenue from Rates																					
4080-2	SSS Admin Charge																					
4082	Retail Services Revenues																					
4084	Service Transaction Requests (STR) Revenues																					
4090	Electric Services Incidental to Energy Sales																					
4205	Interdepartmental Rents																					
4210	Rent from Electric Property																					
4215	Other Utility Operating Income																					
4220	Other Electric Revenues																					
4225	Late Payment Charges																					
4235	Miscellaneous Service Revenues																					
4235-1	Account Set Up Charges																					
4235-90	Miscellaneous Service Revenues - Residual																					
4240	Provision for Rate Refunds																					
4245	Government Assistance Directly Credited to Income																					
4305	Regulatory Debits																					
4310	Regulatory Credits																					
4315	Revenues from Electric Plant Leased to Others																					
4320	Expenses of Electric Plant Leased to Others																					
4325	Revenues from Merchandise, Jobbing, Etc.																					
4330	Costs and Expenses of Merchandising, Jobbing, Etc.																					
4335	Profits and Losses from Financial Instrument Hedges																					
4340	Profits and Losses from Financial Instrument Investments																					
4345	Gains from Disposition of Future Use Utility Plant																					
4350	Losses from Disposition of Future Use Utility Plant																					
4355	Gain on Disposition of Utility and Other Property																					
4360	Loss on Disposition of Utility and Other Property																					
4365	Gains from Disposition of Allowances for Emission																					
4370	Losses from Disposition of Allowances for Emission																					
4375	Revenues from Non-Utility Operations																					
4380	Expenses of Non-Utility Operations																					
4390	Miscellaneous Non-Operating Income																					
4395	Rate-Payer Benefit Including Interest																					
4398	Foreign Exchange Gains and Losses, Including Amortization																					
4405	Interest and Dividend Income																					
4415	Equity in Earnings of Subsidiary Companies																					
4705	Power Purchased																					
4708	Charges-WMS																					
4710	Cost of Power Adjustments																					
4712	Charges-One-Time																					
4714	Charges-NW																					
4715	System Control and Load Dispatching																					
4716	Charges-CN																					
4730	Rural Rate Assistance Expense																					
4750	Charges-LV																					
5005	Operation Supervision and Engineering																					
5010	Load Dispatching																					
5012	Station Buildings and Fixtures Expense																					
5014	Transformer Station Equipment - Operation Labour																					
5015	Transformer Station Equipment - Operation Supplies and Expenses																					
5016	Distribution Station Equipment - Operation Labour																					
5017	Distribution Station Equipment - Operation Supplies and Expenses																					
5020	Overhead Distribution Lines and Feeders - Operation Labour																					
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses																					
5030	Overhead Subtransmission Feeders - Operation																					
5035	Overhead Distribution Transformers- Operation																					

					Categorization			1	2	4	5	6	7	9		1	2	4	5	6	7	9
USoA Account #	Accounts	Reclassified Balance	Financial Statement Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total - Demand	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
5040	Underground Distribution Lines and Feeders - Operation Labour																					
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses																					
5050	Underground Subtransmission Feeders - Operation																					
5055	Underground Distribution Transformers - Operation																					
5065	Meter Expense																					
5070	Customer Premises - Operation Labour																					
5075	Customer Premises - Materials and Expenses																					
5085	Miscellaneous Distribution Expense																					
5090	Underground Distribution Lines and Feeders - Rental Paid																					
5095	Overhead Distribution Lines and Feeders - Rental Paid																					
5096	Other Rent																					
5105	Maintenance Supervision and Engineering																					
5110	Maintenance of Buildings and Fixtures - Distribution Stations																					
5112	Maintenance of Transformer Station Equipment																					
5114	Maintenance of Distribution Station Equipment																					
5120	Maintenance of Poles, Towers and Fixtures																					
5125	Maintenance of Overhead Conductors and Devices																					
5130	Maintenance of Overhead Services																					
5135	Overhead Distribution Lines and Feeders - Right of Way																					
5145	Maintenance of Underground Conduit																					
5150	Maintenance of Underground Conductors and Devices																					
5155	Maintenance of Underground Services																					
5160	Maintenance of Line Transformers																					
5175	Maintenance of Meters																					
5305	Supervision																					
5310	Meter Reading Expense																					
5315	Customer Billing																					
5320	Collecting																					
5325	Collecting- Cash Over and Short																					
5330	Collection Charges																					
5335	Bad Debt Expense																					
5340	Miscellaneous Customer Accounts Expenses																					
5405	Supervision																					
5410	Community Relations - Sundry																					
5415	Energy Conservation																					
5420	Community Safety Program																					
5425	Miscellaneous Customer Service and Informational Expenses																					
5505	Supervision																					
5510	Demonstrating and Selling Expense																					
5515	Advertising Expense																					
5520	Miscellaneous Sales Expense																					
5605	Executive Salaries and Expenses																					
5610	Management Salaries and Expenses																					
5615	General Administrative Salaries and Expenses																					
5620	Office Supplies and Expenses																					
5625	Administrative Expense Transferred Credit																					
5630	Outside Services Employed																					
5635	Property Insurance																					
5640	Injuries and Damages																					
5645	Employee Pensions and Benefits																					
5650	Franchise Requirements																					
5655	Regulatory Expenses																					
5660	General Advertising Expenses																					
5665	Miscellaneous General Expenses																					
5670	Rent																					
5675	Maintenance of General Plant																					
5680	Electrical Safety Authority Fees																					
5681	IFRS Placeholder Expense Account																					
5682	IFRS Placeholder Expense Account																					
5683	IFRS Placeholder Expense Account																					
5684	IFRS Placeholder Expense Account																					
5685	Independent Market Operator Fees and Penalties																					
5705	Amortization Expense - Property, Plant, and Equipment																					
5710	Amortization of Limited Term Electric Plant																					
5715	Amortization of Intangibles and Other Electric Plant	$3,197,218	$0	$3,197,218			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0	$0	$0			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

USoA Account #	Accounts	Reclassified Balance	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total - Demand	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
				Categorization				1	2	4	5	6	7	9		1	2	4	5	6	7	9
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0		$0																		
5735	Amortization of Deferred Development Costs	$0		$0																		
5740	Amortization of Deferred Charges	$0		$0																		
6005	Interest on Long Term Debt	$18,395,000		$18,395,000				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6105	Taxes Other Than Income Taxes	$1,200,000		$1,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6110	Income Taxes	$2,981,000		$2,981,000			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6205	Donations	$150,000		$150,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6210	Life Insurance	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$1,221,932,043	$0	$1,221,932,043	$355,794,775	$193,570,491	$549,365,266	$76,451,000	$23,849,029	$117,887,362	$92,229,145	$26,118,811	$136,611	$78,028	$336,749,985	$132,908,351	$25,858,007	$11,566,246	$3,056,725	$839,473	$6,323,411	$1,725,670
							O5 Summary	O4 Summary														
					$19,044,790	$11,292,608	$1,336,476,697	$1,336,476,697														
							($114,544,654)															
				$0			$1,221,932,043															

Grouping by Allocator	Adjusted TB	Demand	Customer	Total	Residential	GS < 50kW	GS>50-Regular	GS 50 - 499kW	Large User > 5MW	Street Light	Sentinel	Unmetered	Back-up/Standby Power	GS < 50kW	GS>50-Regular	GS 50 - 499kW	Large User > 5MW	Street Light	Sentinel	Unmetered	Back-up/Standby Power
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 1,710,989.00	$ 1,710,989.00	$ -	$ 1,710,989.00	$ 361,124.02	$ 113,650.25	$ -	$ 566,751.16	$ 180,922.69	$ 488.46	$ -	$ 230.97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 2,679,514.00	$ -	$ 2,679,514.00	$ 2,679,514.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 351,496.79	$ -	$ 380,999.36	$ -	$ 109,422.45	$ -	$ 29,583.01	$ -
1860	$ 1,801,916.00	$ -	$ 1,801,916.00	$ 1,801,916.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 528,753.57	$ -	$ 160,282.66	$ 1,966.70	$ -	$ -	$ -	$ -
1815-1855	$ 7,585,581.00	$ 5,309,906.70	$ 2,275,674.30	$ 7,585,581.00	$ 1,208,151.53	$ 380,253.30	$ -	$ 1,876,235.70	$ 392.956.22	$ 1,361.88	$ -	$ 700.35	$ -	$ 200,651.95	$ -	$ 101,937.12	$ 13,988.51	$ 108,742.84	$ -	$ 29,472.54	$ -
1830 & 1835	$ 2,689,322.00	$ 1,882,525.40	$ 806,796.60	$ 2,689,322.00	$ 426,412.16	$ 134,208.18	$ -	$ 662,612.95	$ 143,005.58	$ 486.20	$ -	$ 248.66	$ -	$ 66,705.93	$ -	$ 14,812.67	$ 24.52	$ 41,297.58	$ -	$ 11,165.04	$ -
1840 & 1845	$ 3,498,470.00	$ 2,448,929.00	$ 1,049,541.00	$ 3,498,470.00	$ 550,463.09	$ 173,250.26	$ -	$ 856,276.92	$ 194,215.23	$ 639.96	$ -	$ 324.27	$ -	$ 86,791.43	$ -	$ 19,292.89	$ 33.30	$ 53,719.15	$ -	$ 14,523.29	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 3,550,000.00	$ -	$ 3,550,000.00	$ 3,550,000.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,082,902.45	$ -	$ 571,382.75	$ -	$ -	$ -	$ 1,630.19	$ -
Break Out	$ (38,575,022.70)	$ -	$ -	$ -	$ (4,344,190.85)	$ (1,362,374.42)	$ -	$ (6,723,930.99)	$ (1,408,384.17)	$ (6,018.21)	$ -	$ (3,285.05)	$ -	$ (1,639,274.06)	$ -	$ (618,007.62)	$ (39,456.80)	$ (394,963.47)	$ -	$ (106,969.19)	$ -
CCA	$ 1,716,475.00	$ -	$ 1,716,475.00	$ 1,716,475.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 142,784.88	$ -	$ 31,859.02	$ 72.59	$ 87,769.20	$ -	$ 23,728.92	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 90,831,797.92	$ -	$ 6,051,945.92	$ 6,051,945.92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 497,187.91	$ -	$ 1,737,720.47	$ 809,813.54	$ 15,446.85	$ -	$ 8,432.56	$ -
CEN EWMP	$648,500,146.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	##############	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ 15,157,937.12	$ -	$ 15,157,937.12	$ 15,157,937.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,988,407.71	$ -	$ 2,155,302.90	$ -	$ 618,999.82	$ -	$ 167,350.25	$ -
CWMC	$ 39,022,350.93	$ -	$ 39,022,350.93	$ 39,022,350.93	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,450,704.41	$ -	$ 3,471,086.50	$ 42,590.98	$ -	$ -	$ -	$ -
CWMR	$ 24,000.00	$ -	$ 24,000.00	$ 24,000.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,585.69	$ -	$ 5,644.17	$ 249.04	$ -	$ -	$ -	$ -
CWNB	$ 7,480,391.00	$ -	$ 8,439,905.00	$ 8,439,905.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,927,115.04	$ -	$ 1,504,963.31	$ 7,347.92	$ 54.43	$ -	$ 10,341.52	$ -
DCP	$ 35,768,172.58	$ 35,768,172.58	$ -	$ 35,768,172.58	$ 8,017,057.59	$ 2,305,245.70	$ -	$ 11,580,521.89	$ 3,772,856.64	$ 60,483.93	$ -	$ 39,096.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (1,800,000.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ 57,276,605.79	$ 37,229,793.76	$ 20,046,812.03	$ 57,276,605.79	$ 9,900,279.96	$ 3,116,510.33	$ -	$ 15,073,933.34	$ -	$ 7,030.88	$ -	$ 4,641.52	$ -	$ 1,650,780.96	$ -	$ 357,867.55	$ -	$ 1,027,790.34	$ -	$ 277,869.18	$ -
NFA	$ (1,357,092.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ 72,332,530.81	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 25,196,495.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$283,226,996.32	$ 216,028,899.16	$ 67,198,097.17	$283,226,996.32	$ 45,595,398.18	$ 14,349,442.34	$ -	$ 71,557,811.49	$ 22,843,238.80	$ 61,672.42	$ -	$ 29,162.29	$ -	$ 5,564,726.20	$ -	$ 1,247,135.50	$ 2,843.01	$ 3,437,504.80	$ -	$ 929,349.71	$ -
SNCP	$ 79,165,085.18	$ 55,415,559.63	$ 23,749,525.55	$ 79,165,085.18	$ 14,736,303.88	$ 4,638,842.89	$ -	$ 22,437,149.59	$ -	$ 10,465.27	$ -	$ 6,908.78	$ -	$ 1,955,685.75	$ -	$ 423,966.89	$ -	$ 1,217,626.67	$ -	$ 329,192.56	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 1,222,938,007**	**$ 355,794,775**	**$ 193,570,491**	**$ 549,365,266**	**$ 76,451,000**	**$ 23,849,029**	**$ -**	**$ 117,887,362**	**$ 26,118,811**	**$ 136,611**	**$ -**	**$ 78,028**	**$ -**	**$ 25,858,007**	**$ -**	**$ 11,566,246**	**$ 839,473**	**$ 6,323,411**	**$ -**	**$ 1,725,670**	**$ -**

2013 COST ALLOCATION
Enersource Hydro Missi
EB-2012-0033
Friday, April 27, 2012
Sheet O5 Details of Allo

Uniform System of Accounts - Detail Accounts

USoA Account #	Accounts	Total - Customer	Allocation of Miscellaneous Revenue 1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered	Total - Mis	Allocation of General Plant and Administration 1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
1565	Conservation and Demand Management Expenditures and Recoveries																
1608	Franchises and Consents																
1805	Land																
1805-1	Land Station >50 kV																
1805-2	Land Station <50 kV																
1806	Land Rights																
1806-1	Land Rights Station >50 kV																
1806-2	Land Rights Station <50 kV																
1808	Buildings and Fixtures																
1808-1	Buildings and Fixtures > 50 kV																
1808-2	Buildings and Fixtures < 50 kV																
1810	Leasehold Improvements																
1810-1	Leasehold Improvements >50 kV																
1810-2	Leasehold Improvements <50 kV																
1815	Transformer Station Equipment - Normally Primary above 50 kV																
1820	Distribution Station Equipment - Normally Primary below 50 kV																
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)																
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)																
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)																
1825	Storage Battery Equipment																
1825-1	Storage Battery Equipment > 50 kV																
1825-2	Storage Battery Equipment <50 kV																
1830	Poles, Towers and Fixtures																
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery																
1830-4	Poles, Towers and Fixtures - Primary																
1830-5	Poles, Towers and Fixtures - Secondary																
1835	Overhead Conductors and Devices																
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery																
1835-4	Overhead Conductors and Devices - Primary																
1835-5	Overhead Conductors and Devices - Secondary																
1840	Underground Conduit																
1840-3	Underground Conduit - Bulk Delivery																
1840-4	Underground Conduit - Primary																
1840-5	Underground Conduit - Secondary																
1845	Underground Conductors and Devices																
1845-3	Underground Conductors and Devices - Bulk Delivery																
1845-4	Underground Conductors and Devices - Primary																
1845-5	Underground Conductors and Devices - Secondary																
1850	Line Transformers																
1855	Services																
1860	Meters																
1880	IFRS Placeholder Asset Account																
1905	Land																
1906	Land Rights																
1908	Buildings and Fixtures																
1910	Leasehold Improvements																
1915	Office Furniture and Equipment																
1920	Computer Equipment - Hardware																
1925	Computer Software																
1930	Transportation Equipment																
1935	Stores Equipment																
1940	Tools, Shop and Garage Equipment																
1945	Measurement and Testing Equipment																
1950	Power Operated Equipment																
1955	Communication Equipment																
1960	Miscellaneous Equipment																
1970	Load Management Controls - Customer Premises																
1975	Load Management Controls - Utility Premises																
1980	System Supervisory Equipment																
1990	Other Tangible Property																

			1	2	4	5	6	7	9		1	2	4	5	6	7	9
USoA Account #	Accounts	Total - Customer	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total - Mis	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered
1995	Contributions and Grants - Credit																
2005	Property Under Capital Leases																
2010	Electric Plant Purchased or Sold																
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment																
2120	Accumulated Amortization of Electric Utility Plant - Intangibles																
3046	Balance Transferred From Income																
4080	Distribution Services Revenue																
4080-1	Revenue from Rates																
4080-2	SSS Admin Charge																
4082	Retail Services Revenues																
4084	Service Transaction Requests (STR) Revenues																
4090	Electric Services Incidental to Energy Sales																
4205	Interdepartmental Rents																
4210	Rent from Electric Property																
4215	Other Utility Operating Income																
4220	Other Electric Revenues																
4225	Late Payment Charges																
4235	Miscellaneous Service Revenues																
4235-1	Account Set Up Charges																
4235-90	Miscellaneous Service Revenues - Residual																
4240	Provision for Rate Refunds																
4245	Government Assistance Directly Credited to Income																
4305	Regulatory Debits																
4310	Regulatory Credits																
4315	Revenues from Electric Plant Leased to Others																
4320	Expenses of Electric Plant Leased to Others																
4325	Revenues from Merchandise, Jobbing, Etc.																
4330	Costs and Expenses of Merchandising, Jobbing, Etc.																
4335	Profits and Losses from Financial Instrument Hedges																
4340	Profits and Losses from Financial Instrument Investments																
4345	Gains from Disposition of Future Use Utility Plant																
4350	Losses from Disposition of Future Use Utility Plant																
4355	Gain on Disposition of Utility and Other Property																
4360	Loss on Disposition of Utility and Other Property																
4365	Gains from Disposition of Allowances for Emission																
4370	Losses from Disposition of Allowances for Emission																
4375	Revenues from Non-Utility Operations																
4380	Expenses of Non-Utility Operations																
4390	Miscellaneous Non-Operating Income																
4395	Rate-Payer Benefit Including Interest																
4398	Foreign Exchange Gains and Losses, Including Amortization																
4405	Interest and Dividend Income																
4415	Equity in Earnings of Subsidiary Companies																
4705	Power Purchased																
4708	Charges-WMS																
4710	Cost of Power Adjustments																
4712	Charges-One-Time																
4714	Charges-NW																
4715	System Control and Load Dispatching																
4716	Charges-CN																
4730	Rural Rate Assistance Expense																
4750	Charges-LV																
5005	Operation Supervision and Engineering																
5010	Load Dispatching																
5012	Station Buildings and Fixtures Expense																
5014	Transformer Station Equipment - Operation Labour																
5015	Transformer Station Equipment - Operation Supplies and Expenses																
5016	Distribution Station Equipment - Operation Labour																
5017	Distribution Station Equipment - Operation Supplies and Expenses																
5020	Overhead Distribution Lines and Feeders - Operation Labour																
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses																
5030	Overhead Subtransmission Feeders - Operation																
5035	Overhead Distribution Transformers- Operation																

USoA Account #	Accounts	Total - Customer	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered	Total - Mis	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
5040	Underground Distribution Lines and Feeders - Operation Labour																
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses																
5050	Underground Subtransmission Feeders - Operation																
5055	Underground Distribution Transformers - Operation																
5065	Meter Expense																
5070	Customer Premises - Operation Labour																
5075	Customer Premises - Materials and Expenses																
5085	Miscellaneous Distribution Expense																
5090	Underground Distribution Lines and Feeders - Rental Paid																
5095	Overhead Distribution Lines and Feeders - Rental Paid																
5096	Other Rent																
5105	Maintenance Supervision and Engineering																
5110	Maintenance of Buildings and Fixtures - Distribution Stations																
5112	Maintenance of Transformer Station Equipment																
5114	Maintenance of Distribution Station Equipment																
5120	Maintenance of Poles, Towers and Fixtures																
5125	Maintenance of Overhead Conductors and Devices																
5130	Maintenance of Overhead Services																
5135	Overhead Distribution Lines and Feeders - Right of Way																
5145	Maintenance of Underground Conduit																
5150	Maintenance of Underground Conductors and Devices																
5155	Maintenance of Underground Services																
5160	Maintenance of Line Transformers																
5175	Maintenance of Meters																
5305	Supervision																
5310	Meter Reading Expense																
5315	Customer Billing																
5320	Collecting																
5325	Collecting- Cash Over and Short																
5330	Collection Charges																
5335	Bad Debt Expense																
5340	Miscellaneous Customer Accounts Expenses																
5405	Supervision																
5410	Community Relations - Sundry																
5415	Energy Conservation																
5420	Community Safety Program																
5425	Miscellaneous Customer Service and Informational Expenses																
5505	Supervision																
5510	Demonstrating and Selling Expense																
5515	Advertising Expense																
5520	Miscellaneous Sales Expense																
5605	Executive Salaries and Expenses																
5610	Management Salaries and Expenses																
5615	General Administrative Salaries and Expenses																
5620	Office Supplies and Expenses																
5625	Administrative Expense Transferred Credit																
5630	Outside Services Employed																
5635	Property Insurance																
5640	Injuries and Damages																
5645	Employee Pensions and Benefits																
5650	Franchise Requirements																
5655	Regulatory Expenses																
5660	General Advertising Expenses																
5665	Miscellaneous General Expenses																
5670	Rent																
5675	Maintenance of General Plant																
5680	Electrical Safety Authority Fees																
5681	IFRS Placeholder Expense Account																
5682	IFRS Placeholder Expense Account																
5683	IFRS Placeholder Expense Account																
5684	IFRS Placeholder Expense Account																
5685	Independent Market Operator Fees and Penalties																
5705	Amortization Expense - Property, Plant, and Equipment																
5710	Amortization of Limited Term Electric Plant																
5715	Amortization of Intangibles and Other Electric Plant	$0									$1,265,931	$289,052	$811,001	$607,448	$172,316	$40,286	$11,184
5720	Amortization of Electric Plant Acquisition Adjustments	$0									$0	$0	$0	$0	$0	$0	$0

USoA Account #	Accounts	Total - Customer	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered	Total - Mis	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
5730	Amortization of Unrecovered Plant and Regulatory Study Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5735	Amortization of Deferred Development Costs		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,272,954	$1,665,857	$4,668,957	$3,498,729	$994,028	$230,470	$64,006
6105	Taxes Other Than Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$474,452	$108,672	$304,580	$228,240	$64,846	$15,035	$4,175
6110	Income Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,178,618	$269,960	$756,627	$566,986	$161,087	$37,349	$10,373
6205	Donations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$75,095	$23,715	$29,577	$15,295	$4,045	$1,746	$527
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		$182,277,882	($11,725,165)	($2,865,932)	($6,618,992)	($4,776,323)	($1,285,117)	($330,654)	($96,387)	($27,698,570)	$187,030,927	$72,064,156	$237,506,286	$240,403,182	$103,474,419	$3,255,403	$1,413,026

Grouping by Allocator	GS < 50kW	GS>50-Regular	GS 50 - 499kW	Large User > 5MW	Street Light	Sentinel	Unmetered	Back-up/Standby Power	GS < 50kW	GS>50-Regular	GS 50 - 499kW	Large User > 5MW	Street Light	Sentinel	Unmetered	Back-up/Standby Power
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (744,741.68)	$ -	$ (2,089,541.99)	$ (443,971.11)	$ (103,797.83)	$ -	$ (28,815.02)	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,964,952.70	$ -	$ 24,343,192.48	$ 11,344,429.22	$ 216,390.12	$ -	$ 118,129.20	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53,276,488.90	$ -	$186,206,551.51	$ 86,776,089.30	$ 1,655,216.66	$ -	$ 903,596.79	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ (205,297.62)	$ -	$ (174,945.60)	$ (5,967.71)	$ (2,251.93)	$ -	$ (1,616.69)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ (314,540.03)	$ -	$ (306,247.77)	$ -	$ -	$ -	$ (3,083.40)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ (2,194,193.83)	$ -	$ (6,044,042.50)	$ (1,278,717.26)	$ (300,993.43)	$ -	$ (83,701.24)	$ -	$ 2,044,489.21	$ -	$ 5,730,164.43	$ 1,219,960.46	$ 282,853.43	$ -	$ 78,554.41	$ -
NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,539,391.07	$ -	$ 18,347,747.44	$ 3,898,399.65	$ 911,422.90	$ -	$ 253,017.50	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,983,575.74	$ -	$ 4,968,172.11	$ 679,511.73	$ 293,317.89	$ -	$ 88,542.90	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**-$ 2,714,031**	**$ -**	**-$ 6,525,236**	**-$ 1,284,685**	**-$ 303,245**	**$ -**	**-$ 88,401**	**$ -**	**$ 72,064,156**	**$ -**	**$ 237,506,286**	**$ 103,474,419**	**$ 3,255,403**	**$ -**	**$ 1,413,026**	**$ -**

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O6 Composite Allocator Detail Worksheet - Run 2

Details:
Output Sheet Details How Various Composite Allocators are Derived

Demand Allocators can be found in columns C to AG
Customer Allocators can be found in columns AJ to BN

		Demand Allocators								Customer Allocators								
			1	2	4	5	6	7	9		1	2	4	5	6	7	9	
		Demand Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Customer Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total
Composite allocators																		
Rate Base																		
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-1	Land Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805-2	Land Station <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1805	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-1	Land Rights Station >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806-2	Land Rights Station <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1806	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-1	Buildings and Fixtures > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808-2	Buildings and Fixtures < 50 kV		$8,017,058	$2,305,246	$11,580,522	$9,992,911	$3,772,857	$60,484	$39,096	$0	$0	$0	$0	$0	$0	$0	$0	$0
1808	Total	$35,768,173	$8,017,058	$2,305,246	$11,580,522	$9,992,911	$3,772,857	$60,484	$39,096	$0	$0	$0	$0	$0	$0	$0	$0	$35,768,173
1810-1	Leasehold Improvements >50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810-2	Leasehold Improvements <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1810	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$59,233,339	$12,501,881	$3,934,499	$19,620,561	$16,888,065	$6,263,427	$16,910	$7,996	$0	$0	$0	$0	$0	$0	$0	$0	$59,233,339
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$6,051,946	$1,156,384	$497,188	$1,737,720	$1,826,960	$809,814	$15,447	$8,433	$6,051,946
1820	Total	$59,233,339	$12,501,881	$3,934,499	$19,620,561	$16,888,065	$6,263,427	$16,910	$7,996	$6,051,946	$1,156,384	$497,188	$1,737,720	$1,826,960	$809,814	$15,447	$8,433	$65,285,285
1815 & 1820	Total	$59,233,339	$12,501,881	$3,934,499	$19,620,561	$16,888,065	$6,263,427	$16,910	$7,996	$6,051,946	$1,156,384	$497,188	$1,737,720	$1,826,960	$809,814	$15,447	$8,433	$65,285,285
1825-1	Storage Battery Equipment > 50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825-2	Storage Battery Equipment <50 kV		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1825	Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary		$9,633,833	$3,031,888	$15,119,420	$13,013,785	$4,826,538	$13,031	$6,162	$19,561,996	$16,264,270	$1,619,944	$363,053	$42,669	$828	$1,000,690	$270,542	$19,561,996
1830-5	Poles, Towers and Fixtures - Secondary		$4,757,876	$1,497,732	$7,244,230	$4,386,444	$0	$3,379	$2,231	$7,667,954	$6,389,602	$631,428	$136,885	$10,621	$0	$393,132	$106,286	$7,667,954
1830	Total	$63,536,549	$14,391,709	$4,529,620	$22,363,651	$17,400,229	$4,826,538	$16,410	$8,392	$27,229,950	$22,653,872	$2,251,372	$499,938	$53,290	$828	$1,393,822	$376,828	$90,766,499
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary		$1,703,519	$536,119	$2,673,518	$2,301,185	$853,461	$2,304	$1,090	$3,459,084	$2,875,958	$286,449	$64,197	$7,545	$146	$176,949	$47,839	$3,459,084
1835-5	Overhead Conductors and Devices - Secondary		$841,320	$264,839	$1,280,974	$775,641	$0	$597	$394	$1,355,899	$1,129,852	$111,653	$24,205	$1,878	$0	$69,516	$18,794	$1,355,899
1835	Total	$11,234,960	$2,544,839	$800,958	$3,954,491	$3,076,826	$853,461	$2,902	$1,484	$4,814,983	$4,005,810	$398,103	$88,402	$9,423	$146	$246,465	$66,633	$16,049,944
1830 & 1835	Total	$74,771,510	$16,936,548	$5,330,578	$26,318,142	$20,477,055	$5,680,000	$19,311	$9,876	$32,044,933	$26,659,682	$2,649,474	$588,340	$62,713	$974	$1,640,287	$443,461	$106,816,442
1840-3	Underground Conduit - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary		$4,067,819	$1,280,194	$6,384,070	$5,494,980	$2,037,972	$5,502	$2,602	$8,259,917	$6,867,475	$684,010	$153,297	$18,017	$349	$422,534	$114,235	$8,259,917
1840-5	Underground Conduit - Secondary		$1,708,394	$537,786	$2,601,161	$1,575,025	$0	$1,213	$801	$2,753,306	$2,294,292	$226,725	$49,151	$3,814	$0	$141,161	$38,164	$2,753,306
1840	Total	$25,697,520	$5,776,213	$1,817,979	$8,985,231	$7,070,006	$2,037,972	$6,715	$3,403	$11,013,223	$9,161,768	$910,735	$202,447	$21,830	$349	$563,695	$152,398	$36,710,743
1845-3	Underground Conductors and Devices - Bulk Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary		$17,688,346	$5,566,744	$27,760,242	$23,894,158	$8,861,840	$23,925	$11,313	$35,917,100	$29,862,261	$2,974,323	$666,589	$78,343	$1,520	$1,837,332	$496,734	$35,917,100
1845-5	Underground Conductors and Devices - Secondary		$7,428,714	$2,338,486	$11,310,785	$6,848,779	$0	$5,276	$3,483	$11,972,367	$9,976,411	$985,880	$213,726	$16,584	$0	$613,817	$165,949	$11,972,367
1845	Total	$111,742,090	$25,117,060	$7,905,230	$39,071,028	$30,742,937	$8,861,840	$29,201	$14,796	$47,889,467	$39,838,672	$3,960,203	$880,315	$94,926	$1,520	$2,451,149	$662,683	$159,031,558
1840 & 1845	Total	$137,439,610	$30,893,273	$9,723,209	$48,056,259	$37,812,943	$10,899,812	$35,916	$18,199	$58,902,690	$49,000,439	$4,870,938	$1,082,762	$116,757	$1,869	$3,014,844	$815,081	$196,342,300
1850	Line Transformers	$37,229,794	$9,900,280	$3,116,510	$15,073,933	$9,127,398	$0	$7,031	$4,642	$20,046,812	$16,704,736	$1,650,781	$357,868	$27,768	$0	$1,027,790	$277,869	$57,276,606
1815- 1850	Total	$308,674,253	$70,231,982	$22,104,796	$109,068,894	$84,305,461	$22,843,239	$79,169	$40,713	$117,046,381	$93,521,242	$9,668,381	$3,766,690	$2,034,198	$812,657	$5,698,369	$1,544,844	$425,720,633
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$15,157,937	$10,060,640	$1,988,408	$2,155,303	$167,236	$0	$619,000	$167,350	$15,157,937
1815- 1855	Total	$308,674,253	$70,231,982	$22,104,796	$109,068,894	$84,305,461	$22,843,239	$79,169	$40,713	$132,204,318	$103,581,882	$11,656,789	$5,921,993	$2,201,435	$812,657	$6,317,368	$1,712,194	$440,878,570
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$38,015,782	$22,839,664	$11,155,337	$3,381,551	$597,737	$41,492	$0	$0	$38,015,782
1815-1860	Total	$308,674,253	$70,231,982	$22,104,796	$109,068,894	$84,305,461	$22,843,239	$79,169	$40,713	$170,220,100	$126,421,546	$22,812,126	$9,303,544	$2,799,172	$854,149	$6,317,368	$1,712,194	$478,894,352
1880	FRS Placeholder Asset Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1815-1880	Total	$308,674,253	$70,231,982	$22,104,796	$109,068,894	$84,305,461	$22,843,239	$79,169	$40,713	$170,220,100	$126,421,546	$22,812,126	$9,303,544	$2,799,172	$854,149	$6,317,368	$1,712,194	$478,894,352
1565-1880	Total	$344,442,425	$78,249,040	$24,410,041	$120,649,416	$94,298,371	$26,616,095	$139,653	$79,809	$170,220,100	$126,421,546	$22,812,126	$9,303,544	$2,799,172	$854,149	$6,317,368	$1,712,194	$514,662,525
Distribution Plant	GFA - Distribution plant (credit to contributed capital)	$505,936,066	$200,940,314	$46,506,183	$127,816,259	$95,539,707	$27,068,252	$6,312,719	$1,752,632									
	GFA - Distribution plant (exclude credit for contributed capital)	$514,662,525	$204,670,586	$47,222,167	$129,952,961	$97,097,543	$27,470,244	$6,457,021	$1,792,003									

		Demand Allocators								Customer Allocators								
			1	2	4	5	6	7	9		1	2	4	5	6	7	9	
		Demand Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Customer Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total
	Accum Depreciation - NFA	($42,317,362)	($17,636,302)	($4,520,737)	($10,142,118)	($7,359,439)	($2,015,254)	($504,067)	($139,445)									
	Accum Depreciation - NFA ECC	($42,634,424)	($17,772,119)	($4,547,366)	($10,219,111)	($7,415,683)	($2,030,042)	($509,251)	($140,860)									
NFA	Net Fixed Assets	$463,618,704	$183,304,012	$41,985,446	$117,674,141	$88,180,268	$25,052,998	$5,808,653	$1,613,186									
NFA ECC	Net Fixed Assets Excluding credit for Capital Contribution	$472,028,101	$186,898,476	$42,674,801	$119,733,850	$89,681,860	$25,440,202	$5,947,769	$1,651,143									
1830-4	Primary Poles Demand and Customer																	
1830-5 POLE	Secondary Poles Demand and Customer																	
Operating and Maintenance																		
Acccounts																		
5005	Operation Supervision and Engineering																	
5010	Load Dispatching																	
5012	Station Buildings and Fixtures Expense																	
5014	Transformer Station Equipment - Operation Labour																	
5015	Transformer Station Equipment - Operation Supplies and Expenses																	
5016	Distribution Station Equipment - Operation Labour																	
5017	Distribution Station Equipment - Operation Supplies and Expenses																	
5020	Overhead Distribution Lines and Feeders - Operation Labour																	
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses																	
5030	Overhead Subtransmission Feeders - Operation																	
5035	Overhead Distribution Transformers- Operation																	
5040	Underground Distribution Lines and Feeders - Operation Labour																	
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses																	
5050	Underground Subtransmission Feeders - Operation																	
5055	Underground Distribution Transformers - Operation																	
5065	Meter Expense																	
5070	Customer Premises - Operation Labour																	
5075	Customer Premises - Materials and Expenses																	
5085	Miscellaneous Distribution Expense																	
5090	Underground Distribution Lines and Feeders - Rental Paid																	
5095	Overhead Distribution Lines and Feeders - Rental Paid																	
5096	Other Rent																	
5105	Maintenance Supervision and Engineering																	
5110	Maintenance of Buildings and Fixtures - Distribution Stations																	
5112	Maintenance of Transformer Station Equipment																	
5114	Maintenance of Distribution Station Equipment																	
5120	Maintenance of Poles, Towers and Fixtures																	
5125	Maintenance of Overhead Conductors and Devices																	
5130	Maintenance of Overhead Services																	
5135	Overhead Distribution Lines and Feeders - Right of Way																	
5145	Maintenance of Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5150	Maintenance of Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5160	Maintenance of Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5175	Maintenance of Meters	$0	$0	$0	$0	$0	$0	$0	$0	$1,771,617	$1,082,581	$528,754	$160,283	$28,332	$1,967	$0	$0	
5305	Supervision	$0	$0	$0	$0	$0	$0	$0	$0	$3,753,984	$2,191,415	$877,384	$685,185	$80,488	$3,345	$25	$4,708	
5310	Meter Reading Expense	$0	$0	$0	$0	$0	$0	$0	$0	$21,475	$13,245	$2,586	$5,644	$2,276	$249	$0	$0	
5315	Customer Billing	$0	$0	$0	$0	$0	$0	$0	$0	$4,149,350	$2,422,213	$969,789	$757,348	$88,964	$3,698	$27	$5,204	
5320	Collecting	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5325	Collecting- Cash Over and Short	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
5335	Bad Debt Expense	$0	$0	$0	$0	$0	$0	$0	$0	$3,435,253	$1,780,967	$1,082,902	$571,383	$113,117	$0	$0	$1,630	
5340	Miscellaneous Customer Accounts Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$342,041	$199,669	$79,942	$62,430	$7,334	$305	$2	$429	
O&M DC	Total	$11,352,350	$2,546,151	$801,362	$3,961,877	$3,127,380	$911,100	$2,977	$1,504	$22,392,964	$14,827,099	$4,685,155	$2,880,710	$411,196	$24,781	$401,006	$120,445	
O&M	Total Demand and Customer	$34,702,741	$17,373,250	$5,486,517	$6,842,586	$3,538,576	$935,881	$403,982	$121,949									
Accounts																		
4705	Power Purchased																	
4708	Charges-WMS																	
4710	Cost of Power Adjustments																	
4712	Charges-One-Time																	
4714	Charges-NW																	
4716	Charges-CN																	
4730	Rural Rate Assistance Expense																	
4750	Charges-LV																	
5685	Independent Market Operator Fees and Penalties																	
COP	Cost of Power																	

		Demand Allocators								Customer Allocators									
			1	2	4	5	6	7	9		1	2	4	5	6	7	9		
		Demand Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Customer Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total
Acccounts																			
5005	Operation Supervision and Engineering																		
5010	Load Dispatching																		
5012	Station Buildings and Fixtures Expense																		
5014	Transformer Station Equipment - Operation Labour																		
5015	Transformer Station Equipment - Operation Supplies and Expenses																		
5016	Distribution Station Equipment - Operation Labour																		
5017	Distribution Station Equipment - Operation Supplies and Expenses																		
5020	Overhead Distribution Lines and Feeders - Operation Labour																		
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses																		
5030	Overhead Subtransmission Feeders - Operation																		
5035	Overhead Distribution Transformers- Operation																		
5040	Underground Distribution Lines and Feeders - Operation Labour																		
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses																		
5050	Underground Subtransmission Feeders - Operation																		
5055	Underground Distribution Transformers - Operation																		
5065	Meter Expense																		
5070	Customer Premises - Operation Labour																		
5075	Customer Premises - Materials and Expenses																		
5085	Miscellaneous Distribution Expense																		
5090	Underground Distribution Lines and Feeders - Rental Paid																		
5095	Overhead Distribution Lines and Feeders - Rental Paid																		
5096	Other Rent																		
5105	Maintenance Supervision and Engineering																		
5110	Maintenance of Buildings and Fixtures - Distribution Stations																		
5112	Maintenance of Transformer Station Equipment																		
5114	Maintenance of Distribution Station Equipment																		
5120	Maintenance of Poles, Towers and Fixtures																		
5125	Maintenance of Overhead Conductors and Devices																		
5130	Maintenance of Overhead Services																		
5135	Overhead Distribution Lines and Feeders - Right of Way																		
5145	Maintenance of Underground Conduit																		
5150	Maintenance of Underground Conductors and Devices																		
5155	Maintenance of Underground Services																		
5160	Maintenance of Line Transformers																		
5175	Maintenance of Meters																		
5305	Supervision																		
5310	Meter Reading Expense																		
5315	Customer Billing																		
5320	Collecting																		
5325	Collecting- Cash Over and Short																		
5330	Collection Charges																		
5335	Bad Debt Expense																		
5340	Miscellaneous Customer Accounts Expenses																		
5405	Supervision																		
5410	Community Relations - Sundry																		
5415	Energy Conservation																		
5420	Community Safety Program																		
5425	Miscellaneous Customer Service and Informational Expenses																		
5505	Supervision																		
5510	Demonstrating and Selling Expense																		
5515	Advertising Expense																		
5520	Miscellaneous Sales Expense																		
5605	Executive Salaries and Expenses																		
5610	Management Salaries and Expenses																		
5615	General Administrative Salaries and Expenses																		
5620	Office Supplies and Expenses																		
5625	Administrative Expense Transferred Credit																		
5630	Outside Services Employed																		
5635	Property Insurance																		
5640	Injuries and Damages	$1,086,443	$543,906	$171,767	$214,222	$110,783	$29,300	$12,648	$3,818	$1,086,443									
5645	Employee Pensions and Benefits	$0	$0	$0	$0	$0	$0	$0	$0	$0									
5650	Franchise Requirements	$0	$0	$0	$0	$0	$0	$0	$0	$0									
5655	Regulatory Expenses	$1,091,500	$546,438	$172,567	$215,219	$111,298	$29,436	$12,706	$3,836	$1,091,500									
5660	General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0									
5665	Miscellaneous General Expenses	$313,020	$156,707	$49,489	$61,720	$31,918	$8,442	$3,644	$1,100	$313,020									
5670	Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0									
5675	Maintenance of General Plant	$9,219,951	$4,615,788	$1,457,678	$1,817,963	$940,142	$248,648	$107,331	$32,400	$9,219,951									
5680	Electrical Safety Authority Fees	$97,850	$48,987	$15,470	$19,294	$9,978	$2,639	$1,139	$344	$97,850									
5681	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0									
5682	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0									
5683	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0									
5684	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0									
6105	Taxes Other Than Income Taxes	$1,200,000	$474,452	$108,672	$304,580	$228,240	$64,846	$15,035	$4,175	$1,200,000									
6205	Donations	$150,000	$75,065	$23,715	$29,577	$15,295	$4,045	$1,746	$527	$150,000									
6210	Life Insurance	$0	$0	$0	$0	$0	$0	$0	$0	$0									
6215	Penalties	$0	$0	$0	$0	$0	$0	$0	$0	$0									
6225	Other Deductions	$0	$0	$0	$0	$0	$0	$0	$0	$0									
	OM&A Expenses	**$61,099,236**	**$30,461,835**	**$9,578,765**	**$12,115,338**	**$6,336,057**	**$1,680,238**	**$712,335**	**$214,667**	**$61,099,236**									

	Demand Allocators								Customer Allocators							
		1	2	4	5	6	7	9		1	2	4	5	6	7	9	
	Demand Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Customer Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total

Grouping of Operating and Maintenance Distribution Costs (lines 106 - 148)

	Demand Allocators									Customer Allocators							
	Demand Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Customer Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 1,710,989	$ 361,124	$ 113,650	$ 566,751	$ 487,821	$ 180,923	$ 488	$ 231	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,510,946	$ 1,778,449	$ 351,497	$ 380,999	$ 29,563	$ -	$ 109,422	$ 29,583	$ -
1860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,771,617	$ 1,082,581	$ 528,754	$ 160,283	$ 28,332	$ 1,967	$ -	$ -	$ -
1815-1855	$ 5,309,907	$ 1,208,152	$ 380,253	$ 1,876,236	$ 1,450,248	$ 392,956	$ 1,362	$ 700	$ 2,085,576	$ 1,782,987	$ 200,652	$ 101,937	$ 37,894	$ 13,989	$ 108,743	$ 29,473	$ -
1830 & 1835	$ 1,882,525	$ 426,412	$ 134,208	$ 662,613	$ 515,552	$ 143,006	$ 486	$ 249	$ 752,731	$ 671,212	$ 66,706	$ 14,813	$ 1,579	$ 25	$ 41,298	$ 11,165	$ -
1840 & 1845	$ 2,448,929	$ 550,463	$ 173,250	$ 856,277	$ 673,759	$ 194,215	$ 640	$ 324	$ 979,185	$ 873,101	$ 86,791	$ 19,293	$ 2,080	$ 33	$ 53,719	$ 14,523	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,435,253	$ 1,780,967	$ 1,082,902	$ 571,383	$ 113,117	$ -	$ -	$ 1,630	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,601,162	$ 1,426,518	$ 142,785	$ 31,859	$ 3,742	$ 73	$ 87,769	$ 23,729	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 989,644	$ 604,741	$ 295,367	$ 89,536	$ 15,827	$ 1,099	$ -	$ -	$ -
CWMR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,475	$ 13,245	$ 2,586	$ 5,644	$ 2,276	$ 249	$ -	$ -	$ -
CWNB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,245,376	$ 4,813,297	$ 1,927,115	$ 1,504,963	$ 176,786	$ 7,348	$ 54	$ 10,342	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 11,352,350	$ 2,546,151	$ 801,362	$ 3,961,877	$ 3,127,380	$ 911,100	$ 2,977	$ 1,504	$ 22,392,964	$ 14,827,099	$ 4,685,155	$ 2,880,710	$ 411,196	$ 24,781	$ 401,006	$ 120,445	$ -

Grouping of OM&A (lines 168 - 240)

	Demand Allocators									Customer Allocators							
	Demand Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Customer Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 1,710,989	$ 361,124	$ 113,650	$ 566,751	$ 487,821	$ 180,923	$ 488	$ 231	$ 1,710,989	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 2,679,514	$ 1,778,449	$ 351,497	$ 380,999	$ 29,563	$ -	$ 109,422	$ 29,583	$ 2,679,514	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1860	$ 1,801,916	$ 1,082,581	$ 528,754	$ 160,283	$ 28,332	$ 1,967	$ -	$ -	$ 1,801,916	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815-1855	$ 7,585,581	$ 2,991,139	$ 580,905	$ 1,978,173	$ 1,488,142	$ 406,945	$ 110,105	$ 30,173	$ 7,585,581	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830 & 1835	$ 2,689,322	$ 1,097,624	$ 200,914	$ 677,426	$ 517,131	$ 143,030	$ 41,784	$ 11,414	$ 2,689,322	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840 & 1845	$ 3,498,470	$ 1,423,564	$ 260,042	$ 875,570	$ 675,840	$ 194,249	$ 54,359	$ 14,848	$ 3,498,470	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 3,550,000	$ 1,780,967	$ 1,082,902	$ 571,383	$ 113,117	$ -	$ -	$ 1,630	$ 3,550,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Break Out	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA	$ 1,716,475	$ 1,426,518	$ 142,785	$ 31,859	$ 3,742	$ 73	$ 87,769	$ 23,729	$ 1,716,475	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN EWMP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CREV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWCS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMC	$ 1,006,569	$ 604,741	$ 295,367	$ 89,536	$ 15,827	$ 1,099	$ -	$ -	$ 1,006,569	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWMR	$ 24,000	$ 13,245	$ 2,586	$ 5,644	$ 2,276	$ 249	$ -	$ -	$ 24,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CWNB	$ 8,439,905	$ 4,813,297	$ 1,927,115	$ 1,504,963	$ 176,786	$ 7,348	$ 54	$ 10,342	$ 8,439,905	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPHA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LTNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA	$ 1,200,000	$ 474,452	$ 108,672	$ 304,580	$ 228,240	$ 64,846	$ 15,035	$ 4,175	$ 1,200,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NFA ECC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M	$ 25,196,495	$ 12,614,133	$ 3,983,576	$ 4,968,172	$ 2,569,241	$ 679,512	$ 293,318	$ 88,543	$ 25,196,495	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SNCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 61,099,236	$ 30,461,835	$ 9,578,765	$ 12,115,338	$ 6,336,057	$ 1,680,238	$ 712,335	$ 214,667	$ 61,099,236	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet O7 Amortization Output Worksheet - Run 2

Categorization and Allocation of Contributed Capital
Contributed Capital - 1995

						Demand Allocation								Customer Allocation								A & G Allocation							
						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV (Wholesale)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV (Other)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-4	Poles, Towers and Fixtures - Primary	($1,778,965)	($1,245,275)	($533,689)	($1,778,965)	($262,832)	($82,716)	($412,487)	($355,041)	($131,677)	($356)	($168)	($1,245,275)	($443,721)	($44,195)	($9,905)	($1,164)	($23)	($27,301)	($7,381)	($533,689)								
1830-5	Poles, Towers and Fixtures - Secondary	($697,323)	($488,126)	($209,197)	($697,323)	($129,804)	($40,861)	($197,637)	($119,671)	$0	($92)	($61)	($488,126)	($174,321)	($17,227)	($3,734)	($290)	$0	($10,725)	($2,900)	($209,197)								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	($195,632)	($136,943)	($58,690)	($195,632)	($28,903)	($9,096)	($45,361)	($39,044)	($14,481)	($39)	($18)	($136,943)	($48,796)	($4,860)	($1,089)	($128)	($2)	($3,002)	($812)	($58,690)								
1835-5	Overhead Conductors and Devices - Secondary	($76,684)	($53,679)	($23,005)	($76,684)	($14,275)	($4,403)	($21,734)	($13,160)	$0	($10)	($7)	($53,679)	($19,170)	($1,894)	($411)	($32)	$0	($1,179)	($319)	($23,005)								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	($657,305)	($460,114)	($197,192)	($657,305)	($97,112)	($30,562)	($152,409)	($131,183)	($48,653)	($131)	($62)	($460,114)	($163,949)	($16,330)	($3,660)	($430)	($8)	($10,087)	($2,727)	($197,192)								
1840-5	Underground Conduit - Secondary	($219,102)	($153,371)	($65,731)	($219,102)	($40,785)	($12,839)	($62,098)	($37,601)	$0	($29)	($19)	($153,371)	($54,772)	($5,413)	($1,173)	($91)	$0	($3,370)	($911)	($65,731)								
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	($2,795,536)	($1,956,875)	($838,661)	($2,795,536)	($413,021)	($129,983)	($648,199)	($557,926)	($206,923)	($559)	($264)	($1,956,875)	($697,281)	($69,450)	($15,565)	($1,829)	($35)	($42,902)	($11,599)	($838,661)								
1845-5	Underground Conductors and Devices - Secondary	($931,845)	($652,292)	($279,554)	($931,845)	($173,460)	($54,603)	($264,106)	($159,918)	$0	($123)	($81)	($652,292)	($232,948)	($23,020)	($4,990)	($387)	$0	($14,333)	($3,875)	($279,554)								
1850	Line Transformers	($833,059)	($541,488)	($291,571)	($833,059)	($143,995)	($45,328)	($219,243)	($132,753)	$0	($102)	($68)	($541,488)	($242,962)	($24,010)	($5,205)	($404)	$0	($14,949)	($4,041)	($291,571)								
1855	Services	($367,620)	$0	($367,620)	($367,620)	$0	$0	$0	$0	$0	$0	$0	$0	($243,997)	($48,224)	($52,272)	($4,056)	$0	($15,012)	($4,059)	($367,620)								
1860	Meters	($173,388)	$0	($173,388)	($173,388)	$0	$0	$0	$0	$0	$0	$0	$0	($104,170)	($50,879)	($15,423)	($2,726)	($189)	$0	$0	($173,388)								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	**($8,726,459)**	**($5,688,163)**	**($3,038,296)**	**($8,726,459)**	**($1,304,185)**	**($410,482)**	**($2,023,274)**	**($1,546,299)**	**($401,734)**	**($1,441)**	**($748)**	**($5,688,163)**	**($2,426,088)**	**($305,502)**	**($113,427)**	**($11,537)**	**($258)**	**($142,860)**	**($38,623)**	**($3,038,296)**								
General Plant																													
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 1995	**($8,726,459)**	**($5,688,163)**	**($3,038,296)**	**($8,726,459)**	**($1,304,185)**	**($410,482)**	**($2,023,274)**	**($1,546,299)**	**($401,734)**	**($1,441)**	**($748)**	**($5,688,163)**	**($2,426,088)**	**($305,502)**	**($113,427)**	**($11,537)**	**($258)**	**($142,860)**	**($38,623)**	**($3,038,296)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Accumulated Depreciation - 2105 Capital Contribution

	Demand Allocation								Customer Allocation								A & G Allocation							
	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-4	Poles, Towers and Fixtures - Primary	$50,625	$35,437	$15,187	$50,625	$7,479	$2,354	$11,738	$10,104	$3,747	$10	$5	$35,437	$12,627	$1,258	$282	$33	$1	$777	$210	$15,187								
1830-5	Poles, Towers and Fixtures - Secondary	$19,844	$13,891	$5,953	$19,844	$3,694	$1,163	$5,624	$3,406	$0	$3	$2	$13,891	$4,961	$490	$106	$8	$0	$305	$83	$5,953								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	$7,012	$4,908	$2,104	$7,012	$1,036	$326	$1,626	$1,399	$519	$1	$1	$4,908	$1,749	$174	$39	$5	$0	$108	$29	$2,104								
1835-5	Overhead Conductors and Devices - Secondary	$2,749	$1,924	$825	$2,749	$512	$161	$779	$472	$0	$0	$0	$1,924	$687	$68	$15	$1	$0	$42	$11	$825								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	$19,762	$13,834	$5,929	$19,762	$2,920	$919	$4,582	$3,944	$1,463	$4	$2	$13,834	$4,929	$491	$110	$13	$0	$303	$82	$5,929								
1840-5	Underground Conduit - Secondary	$6,587	$4,611	$1,976	$6,587	$1,226	$386	$1,867	$1,130	$0	$1	$1	$4,611	$1,647	$163	$35	$3	$0	$101	$27	$1,976								
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	$122,223	$85,556	$36,667	$122,223	$18,058	$5,683	$28,340	$24,393	$9,047	$24	$12	$85,556	$30,486	$3,036	$681	$80	$2	$1,876	$507	$36,667								
1845-5	Underground Conductors and Devices - Secondary	$40,741	$28,519	$12,222	$40,741	$7,584	$2,387	$11,547	$6,992	$0	$5	$4	$28,519	$10,185	$1,006	$218	$17	$0	$627	$169	$12,222								
1850	Line Transformers	$24,704	$16,058	$8,647	$24,704	$4,270	$1,344	$6,502	$3,937	$0	$3	$2	$16,058	$7,205	$712	$154	$12	$0	$443	$120	$8,647								
1855	Services	$13,477	$0	$13,477	$13,477	$0	$0	$0	$0	$0	$0	$0	$0	$8,945	$1,768	$1,916	$149	$0	$550	$149	$13,477								
1860	Meters	$9,336	$0	$9,336	$9,336	$0	$0	$0	$0	$0	$0	$0	$0	$5,609	$2,740	$830	$147	$10	$0	$0	$9,336								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	**$317,061**	**$204,738**	**$112,323**	**$317,061**	**$46,779**	**$14,723**	**$72,605**	**$55,776**	**$14,776**	**$52**	**$27**	**$204,738**	**$89,030**	**$11,906**	**$4,387**	**$467**	**$13**	**$5,133**	**$1,388**	**$112,323**								
General Plant																													
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$0**																				$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 2105 CC	$317,061	$204,738	$112,323	$317,061	$46,779	$14,723	$72,605	$55,776	$14,776	$52	$27	$204,738	$89,030	$11,906	$4,387	$467	$13	$5,133	$1,388	$112,323	$0	$0	$0	$0	$0	$0	$0	$0

Accumulated Depreciation - 2105 Fixed Assets Only

						Demand Allocation 1	2	4	5	6	7	9	Sub -total	Customer Allocation 1	2	4	5	6	7	9	Sub -total	A & G Allocation 1	2	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	($2,122,775)	($2,122,775)	$0	($2,122,775)	($475,797)	($136,812)	($687,282)	($593,061)	($223,912)	($3,590)	($2,320)	($2,122,775)	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	($4,417,941)	($4,417,941)	$0	($4,417,941)	($932,457)	($293,456)	($1,463,407)	($1,259,603)	($467,160)	($1,261)	($596)	($4,417,941)	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	($451,387)	$0	($451,387)	($451,387)	$0	$0	$0	$0	$0	$0	$0	$0	($86,249)	($37,083)	($129,609)	($136,265)	($60,400)	($1,152)	($629)	($451,387)								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-4	Poles, Towers and Fixtures - Primary	($3,911,865)	($2,738,306)	($1,173,560)	($3,911,865)	($577,951)	($181,888)	($907,041)	($780,721)	($289,553)	($782)	($370)	($2,738,306)	($975,723)	($97,183)	($21,780)	($2,560)	($50)	($60,033)	($16,230)	($1,173,560)								
1830-5	Poles, Towers and Fixtures - Secondary	($1,533,381)	($1,073,367)	($460,014)	($1,533,381)	($295,434)	($89,852)	($434,594)	($263,151)	$0	($203)	($134)	($1,073,367)	($383,324)	($37,880)	($8,212)	($637)	$0	($23,585)	($6,376)	($460,014)								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	($907,345)	($635,142)	($272,204)	($907,345)	($134,054)	($42,188)	($210,385)	($181,086)	($67,161)	($181)	($86)	($635,142)	($226,316)	($22,541)	($5,052)	($594)	($12)	($13,925)	($3,765)	($272,204)								
1835-5	Overhead Conductors and Devices - Secondary	($355,663)	($248,964)	($106,699)	($355,663)	($66,205)	($20,841)	($100,803)	($61,037)	$0	($47)	($31)	($248,964)	($88,911)	($8,786)	($1,905)	($148)	$0	($5,470)	($1,479)	($106,699)								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	($1,592,210)	($1,114,547)	($477,663)	($1,592,210)	($235,238)	($74,032)	($369,185)	($317,769)	($117,854)	($318)	($150)	($1,114,547)	($397,139)	($39,556)	($8,865)	($1,042)	($20)	($24,435)	($6,606)	($477,663)								
1840-5	Underground Conduit - Secondary	($530,737)	($371,516)	($159,221)	($530,737)	($99,795)	($31,100)	($150,423)	($91,062)	$0	($70)	($46)	($371,516)	($132,477)	($13,111)	($2,842)	($221)	$0	($8,163)	($2,207)	($159,221)								
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	($10,770,640)	($7,539,448)	($3,231,192)	($10,770,640)	($1,591,288)	($500,798)	($2,497,381)	($2,149,578)	($797,233)	($2,152)	($1,018)	($7,539,448)	($2,686,483)	($267,577)	($59,968)	($7,048)	($137)	($165,291)	($44,687)	($3,231,192)								
1845-5	Underground Conductors and Devices - Secondary	($3,590,213)	($2,513,149)	($1,077,064)	($3,590,213)	($668,306)	($210,376)	($1,017,546)	($616,133)	$0	($475)	($313)	($2,513,149)	($897,503)	$88,692)	($19,227)	($1,492)	$0	($55,221)	($14,929)	($1,077,064)								
1850	Line Transformers	($5,288,282)	($3,437,383)	($1,850,899)	($5,288,282)	($914,081)	($287,744)	($1,391,759)	($842,722)	$0	($649)	($429)	($3,437,383)	($1,542,329)	($152,415)	($33,041)	($2,564)	$0	($94,895)	($25,655)	($1,850,899)								
1855	Services	($1,159,603)	$0	($1,159,603)	($1,159,603)	$0	$0	$0	$0	$0	$0	$0	$0	($769,653)	($152,116)	($164,884)	($12,794)	$0	($47,354)	($12,803)	($1,159,603)								
1860	Meters	($6,002,383)	$0	($6,002,383)	($6,002,383)	$0	$0	$0	$0	$0	$0	$0	$0	($3,606,197)	($1,761,337)	($533,919)	($94,378)	($6,551)	$0	$0	$0								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	**($42,634,424)**	**($26,212,536)**	**($16,421,887)**	**($42,634,424)**	**($5,979,606)**	**($1,869,087)**	**($9,229,806)**	**($7,155,942)**	**($1,962,873)**	**($9,728)**	**($5,493)**	**($26,212,536)**	**($11,792,504)**	**($2,678,279)**	**($986,304)**	**($259,741)**	**($67,170)**	**($499,523)**	**($135,367)**	**($16,421,887)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant																													
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	($1,567,726)																				($620,738)	($141,734)	($397,667)	($297,856)	($84,493)	($19,754)	($5,484)	($1,567,726)
1920	Computer Equipment - Hardware	($2,832,286)																				($1,121,437)	($256,059)	($718,433)	($538,113)	($152,648)	($35,688)	($9,907)	($2,832,286)
1925	Computer Software	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	($2,721,070)																				($1,077,402)	($246,005)	($690,222)	($516,983)	($146,653)	($34,287)	($9,518)	($2,721,070)
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	($434,523)																				($172,048)	($39,284)	($110,220)	($82,556)	($23,419)	($5,475)	($1,520)	($434,523)
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	($2,301,719)																				($911,361)	($208,092)	($583,850)	($437,310)	($124,052)	($29,003)	($8,051)	($2,301,719)
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($9,857,324)**																				($3,902,985)	($891,174)	($2,500,392)	($1,872,819)	($531,266)	($124,207)	($34,481)	($9,857,324)
	TOTAL - 2105 FA	($52,491,748)	($26,212,536)	($16,421,887)	($42,634,424)	($5,979,606)	($1,869,087)	($9,229,806)	($7,155,942)	($1,962,873)	($9,728)	($5,493)	($26,212,536)	($11,792,504)	($2,678,279)	($986,304)	($259,741)	($67,170)	($499,523)	($135,367)	($16,421,887)	($3,902,985)	($891,174)	($2,500,392)	($1,872,819)	($531,266)	($124,207)	($34,481)	($9,857,324)

Accumulated Depreciation - 2120

						Demand Allocation 1	2	4	5	6	7	9	Sub -total	Customer Allocation 1	2	4	5	6	7	9	Sub -total	A & G Allocation 1	2	4	5	6	7	9	Sub -total
Account	Description	Accumulated Depreciation	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant																													
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	($6,446,650)																				($2,552,537)	($562,824)	($1,635,246)	($1,224,816)	($347,446)	($81,231)	($22,550)	($6,446,650)
1930	Transportation Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**($6,446,650)**				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**($2,552,537)**	**($562,824)**	**($1,635,246)**	**($1,224,816)**	**($347,446)**	**($81,231)**	**($22,550)**	**($6,446,650)**
	TOTAL - 2120	($6,446,650)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,552,537)	($562,824)	($1,635,246)	($1,224,816)	($347,446)	($81,231)	($22,550)	($6,446,650)

Categorization and Allocation of Amortization Expense - Property, Plant and Equipment - 5705

						Demand Allocation 1	2	4	5	6	7	9	Sub -total	Customer Allocation 1	2	4	5	6	7	9	Sub -total	A & G Allocation 1	2	4	5	6	7	9	Sub -total
Account	Description	Depreciation	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	$1,315,706	$1,315,706	$0	$1,315,706	$294,902	$84,797	$425,981	$367,582	$138,782	$2,225	$1,438	$1,315,706	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$1,794,940	$1,794,940	$0	$1,794,940	$378,843	$119,227	$594,559	$511,757	$189,800	$512	$242	$1,794,940	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$183,391	$0	$183,391	$183,391	$0	$0	$0	$0	$0	$0	$0	$0	$35,042	$15,066	$52,658	$55,362	$24,540	$468	$256	$183,391								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-4	Poles, Towers and Fixtures - Primary	$1,901,910	$1,331,337	$570,573	$1,901,910	$280,994	$88,432	$440,995	$379,579	$140,778	$380	$180	$1,331,337	$474,387	$47,250	$10,589	$1,245	$24	$29,188	$7,891	$570,573								
1830-5	Poles, Towers and Fixtures - Secondary	$745,515	$521,860	$223,654	$745,515	$138,775	$43,685	$211,256	$127,941	$0	$99	$65	$521,860	$186,368	$18,417	$3,993	$310	$0	$11,467	$3,100	$223,654								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	$609,829	$426,880	$182,949	$609,829	$90,098	$28,355	$141,401	$121,708	$45,139	$122	$58	$426,880	$152,108	$15,150	$3,395	$399	$8	$9,359	$2,530	$182,949								
1835-5	Overhead Conductors and Devices - Secondary	$239,042	$167,330	$71,713	$239,042	$44,497	$14,007	$67,750	$41,023	$0	$32	$21	$167,330	$59,757	$5,905	$1,280	$99	$0	$3,677	$994	$71,713								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	$672,579	$470,806	$201,774	$672,579	$99,369	$31,273	$155,950	$134,232	$49,784	$134	$64	$470,806	$167,759	$16,709	$3,745	$440	$9	$10,322	$2,791	$201,774								
1840-5	Underground Conduit - Secondary	$224,193	$156,935	$67,258	$224,193	$41,733	$13,137	$63,541	$38,475	$0	$30	$20	$156,935	$56,045	$5,538	$1,201	$93	$0	$3,448	$932	$67,258								

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	$5,095,509	$3,566,856	$1,528,653	$5,095,509	$752,826	$236,924	$1,181,492	$1,016,949	$377,165	$1,018	$481	$3,566,856	$1,270,955	$126,589	$28,370	$3,334	$65	$78,198	$21,141	$1,528,653								
1845-5	Underground Conductors and Devices - Secondary	$1,698,503	$1,188,952	$509,551	$1,698,503	$316,170	$99,527	$481,394	$291,488	$0	$225	$148	$1,188,952	$424,602	$41,960	$9,096	$706	$0	$26,124	$7,063	$509,551								
1850	Line Transformers	$2,630,107	$1,709,570	$920,537	$2,630,107	$454,615	$143,108	$692,186	$419,125	$0	$323	$213	$1,709,570	$767,071	$75,803	$16,433	$1,275	$0	$47,196	$12,760	$920,537								
1855	Services	$559,354	$0	$559,354	$559,354	$0	$0	$0	$0	$0	$0	$0	$0	$371,255	$73,376	$79,534	$6,171	$0	$22,842	$6,176	$559,354								
1860	Meters	$3,035,845	$0	$3,035,845	$3,035,845	$0	$0	$0	$0	$0	$0	$0	$0	$1,823,918	$890,837	$270,042	$47,734	$3,313	$0	$0	$3,035,845								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	**$20,706,423**	**$12,651,171**	**$8,055,252**	**$20,706,423**	**$2,892,821**	**$902,472**	**$4,456,544**	**$3,449,858**	**$941,447**	**$5,099**	**$2,930**	**$12,651,171**	**$5,789,267**	**$1,332,600**	**$480,337**	**$117,168**	**$27,958**	**$242,288**	**$65,633**	**$8,055,252**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant																													
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$734,835																				$290,956	$66,434	$186,397	$139,613	$39,604	$9,259	$2,570	$734,835
1920	Computer Equipment - Hardware	$1,482,321																				$586,922	$134,013	$376,003	$281,630	$79,890	$18,678	$5,185	$1,482,321
1925	Computer Software	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$1,405,237																				$556,400	$127,044	$356,450	$266,985	$75,736	$17,707	$4,915	$1,405,237
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$199,481																				$78,984	$18,035	$50,600	$37,900	$10,751	$2,514	$698	$199,481
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$1,047,257																				$414,659	$94,680	$265,645	$198,971	$56,442	$13,196	$3,663	$1,047,257
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	**$4,869,131**				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,927,922	$440,205	$1,235,096	$925,099	$262,424	$61,353	$17,032	$4,869,131
	TOTAL - 5705	$25,575,554	$12,651,171	$8,055,252	$20,706,423	$2,892,821	$902,472	$4,456,544	$3,449,858	$941,447	$5,099	$2,930	$12,651,171	$5,789,267	$1,332,600	$480,337	$117,168	$27,958	$242,288	$65,633	$8,055,252	$1,927,922	$440,205	$1,235,096	$925,099	$262,424	$61,353	$17,032	$4,869,131

Categorization and Allocation of Amortization of Limited Term Electric Plant - 5710

						Demand Allocation 1	2	4	5	6	7	9	Sub -total	Customer Allocation 1	2	4	5	6	7	9	Sub -total	A & G Allocation 1	2	4	5	6	7	9	Sub -total
Account	Description	Depreciation	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
General Plant																													

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5710	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Categorization and Allocation of Accumulated Amortization of Electric Utility Plant - Intangibles - 5715

						Demand Allocation 1	2	4	5	6	7	9	Sub -total	Customer Allocation 1	2	4	5	6	7	9	Sub -total	A & G Allocation 1	2	4	5	6	7	9	Sub -total
Account	Description	Depreciation	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																													
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$3,197,218																				$1,265,931	$289,052	$811,001	$607,448	$172,316	$40,286	$11,184	$3,197,218
1930	Transportation Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	**Description**	**Contributed Capital**	**Demand**	**Customer**	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**	**Sub -total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**	**Sub -total**
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$3,197,218				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,265,931	$289,052	$811,001	$607,448	$172,316	$40,286	$11,184	$3,197,218
	TOTAL - 5715	$3,197,218	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,265,931	$289,052	$811,001	$607,448	$172,316	$40,286	$11,184	$3,197,218

Categorization and Allocation of Accum. Amortization of Electric Utility Plant- Property, Plant & Equipment - 5720

						Demand Allocation								Customer Allocation								A & G Allocation							
						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	**Description**	**Depreciation**	**Demand**	**Customer**	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**	**Sub -total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**	**Sub -total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**	**Sub -total**
1565	Conservation and Demand Management	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1805-1	Land Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1805-2	Land Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-1	Land Rights Station >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1806-2	Land Rights Station <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808	Buildings and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-1	Buildings and Fixtures > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1808-2	Buildings and Fixtures < 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-1	Leasehold Improvements >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1810-2	Leasehold Improvements <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820	Distribution Station Equipment - Normally Primary below 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-1	Storage Battery Equipment > 50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1825-2	Storage Battery Equipment <50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-4	Poles, Towers and Fixtures - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1830-5	Poles, Towers and Fixtures - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-4	Overhead Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1835-5	Overhead Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1840-5	Underground Conduit - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-4	Underground Conductors and Devices - Primary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1850	Line Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1855	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1860	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
1880	IFRS Placeholder Expense Account	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0								
	Sub - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General Plant																													
1905	Land	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1906	Land Rights	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1908	Buildings and Fixtures	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1910	Leasehold Improvements	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture and Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equipment - Hardware	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1925	Computer Software	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1930	Transportation Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1935	Stores Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop and Garage Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1945	Measurement and Testing Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1950	Power Operated Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1955	Communication Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1960	Miscellaneous Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1970	Load Management Controls - Customer Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1975	Load Management Controls - Utility Premises	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1980	System Supervisory Equipment	$0																				$0	$0	$0	$0	$0	$0	$0	$0
1990	Other Tangible Property	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2005	Property Under Capital Leases	$0																				$0	$0	$0	$0	$0	$0	$0	$0
2010	Electric Plant Purchased or Sold	$0																				$0	$0	$0	$0	$0	$0	$0	$0
	Sub - Total	$0				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TOTAL - 5720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description	Contributed Capital	Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
						Demand Allocation								Customer Allocation								A & G Allocation							
						1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total	1	2	4	5	6	7	9	Sub -total
Account	Description		Demand	Customer	Total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total	Residential	GS < 50kW	GS 50 - 499kW	GS 500 - 4999kW	Large User > 5MW	Street Light	Unmetered	Sub -total
1565	Conservation and Demand Management	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	50.06%	15.81%	19.72%	10.20%	2.70%	1.16%	0.35%	100.00%								
1805	Land					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1805-1	Land Station >50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1805-2	Land Station <50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1806	Land Rights					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1806-1	Land Rights Station >50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1806-2	Land Rights Station <50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1808	Buildings and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1808-1	Buildings and Fixtures > 50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1808-2	Buildings and Fixtures < 50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1810	Leasehold Improvements					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1810-1	Leasehold Improvements >50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1810-2	Leasehold Improvements <50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1815	Transformer Station Equipment - Normally Primary above 50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1820	Distribution Station Equipment - Normally Primary below 50 kV					22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	100%	100%	0%	100%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	19.11%	8.22%	28.71%	30.19%	13.38%	0.26%	0.14%	100.00%								
1825	Storage Battery Equipment					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1825-1	Storage Battery Equipment > 50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1825-2	Storage Battery Equipment <50 kV	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1830	Poles, Towers and Fixtures					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1830-4	Poles, Towers and Fixtures - Primary	100%	70%	30%	100%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%	100.00%	83.14%	8.28%	1.86%	0.22%	0.00%	5.12%	1.38%	100.00%								
1830-5	Poles, Towers and Fixtures - Secondary	100%	70%	30%	100%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%	100.00%								
1835	Overhead Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1835-4	Overhead Conductors and Devices - Primary	100%	70%	30%	100%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%	100.00%	83.14%	8.28%	1.86%	0.22%	0.00%	5.12%	1.38%	100.00%								
1835-5	Overhead Conductors and Devices - Secondary	100%	70%	30%	100%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%	100.00%								
1840	Underground Conduit					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1840-3	Underground Conduit - Bulk Delivery	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1840-4	Underground Conduit - Primary	100%	70%	30%	100%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%	100.00%	83.14%	8.28%	1.86%	0.22%	0.00%	5.12%	1.38%	100.00%								
1840-5	Underground Conduit - Secondary	100%	70%	30%	100%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%	100.00%								
1845	Underground Conductors and Devices					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1845-3	Underground Conductors and Devices - Bulk Delivery	100%	100%	0%	100%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
1845-4	Underground Conductors and Devices - Primary	100%	70%	30%	100%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%	100.00%	83.14%	8.28%	1.86%	0.22%	0.00%	5.12%	1.38%	100.00%								
1845-5	Underground Conductors and Devices - Secondary	100%	70%	30%	100%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%	100.00%								
1850	Line Transformers	100%	65%	35%	100%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%	100.00%								
1855	Services	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	66.37%	13.12%	14.22%	1.10%	0.00%	4.08%	1.10%	100.00%								
1860	Meters	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	60.08%	29.34%	8.90%	1.57%	0.11%	0.00%	0.00%	100.00%								
1880	IFRS Placeholder Expense Account	100%	0%	100%	100%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%								
General Plant																													
1905	Land	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1906	Land Rights	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1908	Buildings and Fixtures	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1910	Leasehold Improvements	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1915	Office Furniture and Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1920	Computer Equipment - Hardware	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1925	Computer Software	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1930	Transportation Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1935	Stores Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1940	Tools, Shop and Garage Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1945	Measurement and Testing Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1950	Power Operated Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1955	Communication Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1960	Miscellaneous Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1970	Load Management Controls - Customer Premises	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1975	Load Management Controls - Utility Premises	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1980	System Supervisory Equipment	100%																				40%	9%	25%	19%	5%	1%	0%	100%
1990	Other Tangible Property	100%																				40%	9%	25%	19%	5%	1%	0%	100%
2005	Property Under Capital Leases	100%																				40%	9%	25%	19%	5%	1%	0%	100%
2010	Electric Plant Purchased or Sold	100%																				40%	9%	25%	19%	5%	1%	0%	100%

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet E1 Categorization Worksheet - Run 2

This worksheet details how Density is derived and how Costs are Categorized.

Density of Utility

Density	Number of Customers	kM of Lines
78	199182	2552

Deemed Customer Cost Component based on Survey Results

		Customer Component	
If Density is < 30 customers per kM of lines then	LOW	0.6	*All*
If Density is Between 30 and 60 customers per kM of lines then	MEDIUM	0.4	*All*
If Density is Between > 60 customers per kM of lines then	HIGH	0.3	*Distribution*
If Density is Between > 60 customers per kM of lines then	HIGH	0.35	*Transformers*

Categorization and Demand Allocation for Distribution Assets Accounts

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
	Distribution Plant			
1805	Land	DCP		0%
1805-1	Land Station >50 kV	TCP		0%
1805-2	Land Station <50 kV	DCP		0%
1806	Land Rights	DCP		0%
1806-1	Land Rights Station >50 kV	TCP		0%
1806-2	Land Rights Station <50 kV	DCP		0%
1808	Buildings and Fixtures	DCP		0%
1808-1	Buildings and Fixtures > 50 kV	TCP		0%
1808-2	Buildings and Fixtures < 50 KV	DCP		0%
1810	Leasehold Improvements	DCP		0%
1810-1	Leasehold Improvements >50 kV	TCP		0%
1810-2	Leasehold Improvements <50 kV	DCP		0%
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP		0%
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP		0%
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	DCP		0%
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	PNCP		0%
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		CEN	100%
1825	Storage Battery Equipment	DCP		0%
1825-1	Storage Battery Equipment > 50 kV	TCP		0%
1825-2	Storage Battery Equipment <50 kV	DCP		0%
1830	Poles, Towers and Fixtures	DNCP	CCA	30%
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP		0%
1830-4	Poles, Towers and Fixtures - Primary	PNCP	CCP	30%
1830-5	Poles, Towers and Fixtures - Secondary	SNCP	CCS	30%
1835	Overhead Conductors and Devices	DNCP	CCA	30%
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP		0%
1835-4	Overhead Conductors and Devices - Primary	PNCP	CCP	30%
1835-5	Overhead Conductors and Devices - Secondary	SNCP	CCS	30%
1840	Underground Conduit	DNCP	CCA	30%
1840-3	Underground Conduit - Bulk Delivery	BCP		0%
1840-4	Underground Conduit - Primary	PNCP	CCP	30%
1840-5	Underground Conduit - Secondary	SNCP	CCS	30%
1845	Underground Conductors and Devices	DNCP	CCA	30%
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP		0%
1845-4	Underground Conductors and Devices - Primary	PNCP	CCP	30%
1845-5	Underground Conductors and Devices - Secondary	SNCP	CCS	30%
1850	Line Transformers	LTNCP	CCLT	35%
1855	Services		CWCS	100%
1860	Meters		CWMC	100%
1880	IFRS Placeholder Asset Account		0	100%

USoA A/C #	Accounts	Categorization		
		Demand	Customer	Customer Component
1565	Conservation and Demand Management Expenditures and Recoveries		CDMPP	100%
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	See I4 BO Assets		
	Operation			
5005	Operation Supervision and Engineering	1815-1855 D	1815-1855 C	30%
5010	Load Dispatching	1815-1855 D	1815-1855 C	30%
5012	Station Buildings and Fixtures Expense	1808 D		0%
5014	Transformer Station Equipment - Operation Labour	1815 D		0%
5015	Transformer Station Equipment - Operation Supplies and Expenses	1815 D		0%
5016	Distribution Station Equipment - Operation Labour	1820 D		0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	1820 D		0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	1830 & 1835 D	1830 & 1835 C	30%
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	1830 & 1835 D	1830 & 1835 C	30%
5030	Overhead Subtransmission Feeders - Operation	1830 & 1835 D		0%
5035	Overhead Distribution Transformers- Operation	1850 D	1850 C	35%
5040	Underground Distribution Lines and Feeders - Operation Labour	1840 & 1845 D	1840 & 1845 C	30%
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1840 & 1845 D	1840 & 1845 C	30%
5050	Underground Subtransmission Feeders - Operation	1840 & 1845 D		0%
5055	Underground Distribution Transformers - Operation	1850 D	1850 C	35%
5065	Meter Expense		CWMC	100%
5070	Customer Premises - Operation Labour		CCA	100%
5075	Customer Premises - Materials and Expenses		CCA	100%
5085	Miscellaneous Distribution Expense	1815-1855 D	1815-1855 C	30%
5090	Underground Distribution Lines and Feeders - Rental Paid	1840 & 1845 D	1840 & 1845 C	30%
5095	Overhead Distribution Lines and Feeders - Rental Paid	1830 & 1835 D	1830 & 1835 C	30%
	Maintenance			
5105	Maintenance Supervision and Engineering	1815-1855 D	1815-1855 C	30%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1808 D		0%
5112	Maintenance of Transformer Station Equipment	1815 D		0%
5114	Maintenance of Distribution Station Equipment	1820 D		0%
5120	Maintenance of Poles, Towers and Fixtures	1830 D	1830 C	30%
5125	Maintenance of Overhead Conductors and Devices	1835 D	1835 C	30%
5130	Maintenance of Overhead Services		1855 C	100%
5135	Overhead Distribution Lines and Feeders - Right of Way	1830 & 1835 D	1830 & 1835 C	30%
5145	Maintenance of Underground Conduit	1840 D	1840 C	30%
5150	Maintenance of Underground Conductors and Devices	1845 D	1845 C	30%
5155	Maintenance of Underground Services		1855 C	100%
5160	Maintenance of Line Transformers	1850 D	1850 C	35%
5175	Maintenance of Meters		1860 C	100%
5305	Supervision		CWNB	100%
5310	Meter Reading Expense		CWMR	100%
5315	Customer Billing		CWNB	100%
5320	Collecting		CWNB	100%
5325	Collecting- Cash Over and Short		CWNB	100%
5330	Collection Charges		CWNB	100%
5335	Bad Debt Expense		BDHA	100%
5340	Miscellaneous Customer Accounts Expenses		CWNB	100%

2013 COST ALLOCATION

Enersource Hydro Mississauga

EB-2012-0033

Friday, April 27, 2012

Sheet E2 Allocator Worksheet - Run 2

Details:
The worksheet below details how allocators are derived.

Explanation	ID and Factors	Total	1 Residential	2 GS < 50kW	4 GS 50 - 499kW	5 GS 500 - 4999kW	6 Large User > 5MW	7 Street Light	9 Unmetered
Demand Allocators									
1 cp									
Transformation CP	TCP1	100.00%	24.44%	5.96%	33.98%	26.90%	8.63%	0.00%	0.09%
Bulk Delivery (SubTransmission) CP	BCP1	100.00%	24.44%	5.96%	33.98%	26.90%	8.63%	0.00%	0.09%
Distribution CP (Total System)	DCP1	100.00%	24.44%	5.96%	33.98%	26.90%	8.63%	0.00%	0.09%
4 cp									
Transformation CP	TCP4	100.00%	22.80%	6.28%	33.45%	28.28%	9.10%	0.00%	0.09%
Bulk Delivery (SubTransmission) CP	BCP4	100.00%	22.80%	6.28%	33.45%	28.28%	9.10%	0.00%	0.09%
Distribution CP (Total System)	DCP4	100.00%	22.80%	6.28%	33.45%	28.28%	9.10%	0.00%	0.09%
12 cp									
Transformation CP	TCP12	100.00%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%
Bulk Delivery (SubTransmission) CP	BCP12	100.00%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%
Distribution CP (Total System)	DCP12	100.00%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%
NON CO_INCIDENT PEAK									
1 NCP									
Distribution NCP (Total System)	DNCP1	100.00%	26.76%	6.54%	30.84%	26.37%	9.45%	0.03%	0.01%
Primary NCP	PNCP1	100.00%	22.93%	6.40%	32.62%	27.98%	10.03%	0.03%	0.01%
Line Transformer NCP	LTNCP1	100.00%	25.33%	7.10%	36.35%	31.19%	0.00%	0.02%	0.01%
Secondary NCP	SNCP1	100.00%	25.33%	7.10%	36.35%	31.19%	0.00%	0.02%	0.01%
4 NCP									
Distribution NCP (Total System)	DNCP4	100.00%	25.24%	6.78%	31.22%	26.79%	9.93%	0.03%	0.01%
Primary NCP	PNCP4	100.00%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%
Line Transformer NCP	LTNCP4	100.00%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%
Secondary NCP	SNCP4	100.00%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%
12 NCP									
Distribution NCP (Total System)	DNCP12	100.00%	23.79%	6.93%	31.52%	27.03%	10.69%	0.02%	0.01%
Primary NCP	PNCP12	100.00%	19.20%	6.80%	33.60%	28.92%	11.45%	0.02%	0.01%
Line Transformer NCP	LTNCP12	100.00%	21.51%	7.63%	38.07%	32.77%	0.00%	0.01%	0.01%
Secondary NCP	SNCP12	100.00%	21.51%	7.63%	38.07%	32.77%	0.00%	0.01%	0.01%
Demand Allocators - Composite									
DEMAND 1815-1855	1815-1855 D	100.00%	22.75%	7.16%	35.33%	27.31%	7.40%	0.03%	0.01%
DEMAND 1808	1808 D	100.00%	22.41%	6.44%	32.38%	27.94%	10.55%	0.17%	0.11%
DEMAND 1815	1815 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1820	1820 D	100.00%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%
DEMAND 1815 & 1820	1815 & 1820 D	100.00%	21.11%	6.64%	33.12%	28.51%	10.57%	0.03%	0.01%
DEMAND 1830	1830 D	100.00%	22.65%	7.13%	35.20%	27.39%	7.60%	0.03%	0.01%
DEMAND 1835	1835 D	100.00%	22.65%	7.13%	35.20%	27.39%	7.60%	0.03%	0.01%
DEMAND 1830 & 1835	1830 & 1835 D	100.00%	22.65%	7.13%	35.20%	27.39%	7.60%	0.03%	0.01%
DEMAND 1840	1840 D	100.00%	22.48%	7.07%	34.97%	27.51%	7.93%	0.03%	0.01%
DEMAND 1845	1845 D	100.00%	22.48%	7.07%	34.97%	27.51%	7.93%	0.03%	0.01%
DEMAND 1840 & 1845	1840 & 1845 D	100.00%	22.48%	7.07%	34.97%	27.51%	7.93%	0.03%	0.01%
DEMAND 1850	1850 D	100.00%	26.59%	8.37%	40.49%	24.52%	0.00%	0.02%	0.01%
DEMAND 1855	1855 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DEMAND 1860	1860 D	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER ALLOCATORS									
Billing Data									
kWh	CEN	100.00%	19.11%	8.22%	28.71%	30.19%	13.38%	0.26%	0.14%
kW	CDEM	100.00%	0.00%	0.00%	46.94%	39.40%	13.28%	0.38%	0.00%
kWh - Excl WMP	CEN EWMP	100.00%	19.11%	8.22%	28.71%	30.19%	13.38%	0.26%	0.14%
Dollar Billed	CREV	100.00%	38.21%	13.75%	25.32%	15.93%	5.13%	1.15%	0.51%
Bad Debt 3 Year Historical Average	BDHA	100.00%	50.17%	30.50%	16.10%	3.19%	0.00%	0.00%	0.05%
Late Payment 3 Year Historical Average	LPHA	100.00%	53.00%	17.47%	17.01%	12.34%	0.00%	0.00%	0.17%
Number of Bills	CNB	100.00%	79.85%	15.98%	3.57%	0.42%	0.01%	0.00%	0.17%
Number of Connections (Unmetered)	CCON	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	78.72%	21.28%
Embeded Distributor	ED	100.00%	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%

			1	2	4	5	6	7	9
Explanation	**ID and Factors**	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
Total Number of Customer	**CCA**	100.00%	83.11%	8.32%	1.86%	0.22%	0.00%	5.11%	1.38%
Subtransmission Customer Base	**CCB**	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	78.72%	21.28%
Primary Feeder Customer Base	**CCP**	100.00%	83.14%	8.28%	1.86%	0.22%	0.00%	5.12%	1.38%
Line Transformer Customer Base	**CCLT**	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%
Secondary Feeder Customer Base	**CCS**	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%
Weighted - Services	**CWCS**	100.00%	66.37%	13.12%	14.22%	1.10%	0.00%	4.08%	1.10%
Weighted Meter -Capital	**CWMC**	100.00%	60.08%	29.34%	8.90%	1.57%	0.11%	0.00%	0.00%
Weighted Meter Reading	**CWMR**	100.00%	55.19%	10.77%	23.52%	9.48%	1.04%	0.00%	0.00%
Weighted Bills	**CWNB**	100.00%	57.03%	22.83%	17.83%	2.09%	0.09%	0.00%	0.12%
CUSTOMER ALLOCATORS - Composite									
CUSTOMER 1815-1855	**1815-1855 C**	100.00%	78.35%	8.82%	4.48%	1.67%	0.61%	4.78%	1.30%
CUSTOMER 1808	**1808 C**	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1815	**1815 C**	-	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CUSTOMER 1820	**1820 C**	100.00%	19.11%	8.22%	28.71%	30.19%	13.38%	0.26%	0.14%
CUSTOMER 1815 & 1820	**1815 & 1820 C**	100.00%	19.11%	8.22%	28.71%	30.19%	13.38%	0.26%	0.14%
CUSTOMER 1830	**1830 C**	100.00%	83.19%	8.27%	1.84%	0.20%	0.00%	5.12%	1.38%
CUSTOMER 1835	**1835 C**	100.00%	83.19%	8.27%	1.84%	0.20%	0.00%	5.12%	1.38%
CUSTOMER 1830 & 1835	**1830 & 1835 C**	100.00%	83.19%	8.27%	1.84%	0.20%	0.00%	5.12%	1.38%
CUSTOMER 1840	**1840 C**	100.00%	83.19%	8.27%	1.84%	0.20%	0.00%	5.12%	1.38%
CUSTOMER 1845	**1845 C**	100.00%	83.19%	8.27%	1.84%	0.20%	0.00%	5.12%	1.38%
CUSTOMER 1840 & 1845	**1840 & 1845 C**	100.00%	83.19%	8.27%	1.84%	0.20%	0.00%	5.12%	1.38%
CUSTOMER 1850	**1850 C**	100.00%	83.33%	8.23%	1.79%	0.14%	0.00%	5.13%	1.39%
CUSTOMER 1855	**1855 C**	100.00%	66.37%	13.12%	14.22%	1.10%	0.00%	4.08%	1.10%
CUSTOMER 1860	**1860 C**	100.00%	60.08%	29.34%	8.90%	1.57%	0.11%	0.00%	0.00%
Composite Allocators									
Net Fixed Assets	**NFA**	100.00%	39.54%	9.06%	25.38%	19.02%	5.40%	1.25%	0.35%
Net Fixed Assets Excluding Capital Contribution	**NFA ECC**	100.00%	39.59%	9.04%	25.37%	19.00%	5.39%	1.26%	0.35%
5005-5340	**O&M**	100.00%	50.06%	15.81%	19.72%	10.20%	2.70%	1.16%	0.35%
Account Setup	**Acct**	100.00%	50.06%	15.81%	19.72%	10.20%	2.70%	1.16%	0.35%
Access to Poles	**POLE**	100.00%	40.81%	7.47%	25.19%	19.23%	5.32%	1.55%	0.42%
5005-6225	**OM&A**	100.00%	49.86%	15.68%	19.83%	10.37%	2.75%	1.17%	0.35%

2013 COST ALLOCATION
Enersource Hydro Mississaug
EB-2012-0033
Friday, April 27, 2012
Sheet E3 Demand Allocator Worksheet - Run 2

Instructions:
Input sheet for Demand Allocators.

PLCC WATTS
400

		1	2	4	5	6	7	9
Customer Classes	**Total**	**Residential**	**GS < 50kW**	**GS 50 - 499kW**	**GS 500 - 4999kW**	**Large User > 5MW**	**Street Light**	**Unmetered**
CCA	**212,815**	176,865	17,703	3,950	464	9	10,882	2,942
CCB	**13,824**	0	0	0	0	0	10,882	2,942
CCP	**212,726**	176,865	17,616	3,948	464	9	10,882	2,942
CCLT	**212,250**	176,865	17,478	3,789	294	0	10,882	2,942
CCS	**212,250**	176,865	17,478	3,789	294	0	10,882	2,942
PLCC-CCA	**85,126**	70,746	7,081	1,580	186	4	4,353	1,177
PLCC-CCB	**5,530**	0	0	0	0	0	4,353	1,177
PLCC-CCP	**85,090**	70,746	7,046	1,579	186	4	4,353	1,177
PLCC-CCLT	**84,900**	70,746	6,991	1,516	118	0	4,353	1,177
PLCC-CCS	**84,900**	70,746	6,991	1,516	118	0	4,353	1,177
1NCP								
DNCP1	**1,383,636**	368,715	90,149	425,021	363,441	130,185	4,777	1,349
PNCP1	**1,377,438**	367,063	89,745	423,117	361,813	129,602	4,756	1,343
LTNCP1	**1,201,044**	353,421	86,290	407,240	348,222	0	4,579	1,293
SNCP1	**1,201,044**	353,421	86,290	407,240	348,222	0	4,579	1,293
PLCC - 1NCP								
DNCP1A	**1,378,106**	368,715	90,149	425,021	363,441	130,185	424	172
PNCP1A	**1,292,347**	296,317	82,698	421,537	361,628	129,598	403	166
LTNCP1A	**1,116,145**	282,675	79,299	405,725	348,104	0	226	116
SNCP1A	**1,116,145**	282,675	79,299	405,725	348,104	0	226	116
4 NCP								
DNCP4	**5,263,256**	1,322,968	355,208	1,636,507	1,403,880	520,407	18,894	5,393
PNCP4	**5,239,678**	1,317,041	353,616	1,629,175	1,397,590	518,076	18,810	5,369
LTNCP4	**4,044,081**	1,268,093	338,067	1,505,966	908,675	0	18,111	5,169
SNCP4	**4,044,081**	1,268,093	338,067	1,505,966	908,675	0	18,111	5,169
PLCC - 4NCP								
DNCP4A	**5,241,138**	1,322,968	355,208	1,636,507	1,403,880	520,407	1,483	686
PNCP4A	**4,899,316**	1,034,057	325,431	1,622,859	1,396,848	518,061	1,399	661
LTNCP4A	**3,704,481**	985,109	310,103	1,499,904	908,205	0	700	462
SNCP4A	**3,704,481**	985,109	310,103	1,499,904	908,205	0	700	462
12NCP								
DNCP12	**14,621,159**	3,462,435	1,009,205	4,587,026	3,934,159	1,556,636	55,566	16,131
PNCP12	**14,555,658**	3,446,924	1,004,684	4,566,477	3,916,535	1,549,662	55,317	16,058
LTNCP12	**12,502,109**	3,318,818	960,507	4,389,924	3,764,137	0	53,262	15,462
SNCP12	**12,502,109**	3,318,818	960,507	4,389,924	3,764,137	0	53,262	15,462
PLCC - 12NCP								
DNCP12A	**14,554,804**	3,462,435	1,009,205	4,587,026	3,934,159	1,556,636	3,333	2,009
PNCP12A	**13,534,574**	2,597,972	920,127	4,547,527	3,914,308	1,549,619	3,084	1,937
LTNCP12A	**11,483,309**	2,469,866	876,612	4,371,737	3,762,726	0	1,028	1,340
SNCP12A	**11,483,309**	2,469,866	876,612	4,371,737	3,762,726	0	1,028	1,340

2013 COST ALLOCATION

Enersource Hydro Mississauga

EB-2012-0033

Friday, April 27, 2012

Sheet E4 Trial Balance Allocation Detail Worksheet - Run 2

Details:
The worksheet below details how costs are treated, categorized, and grouped.

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. FInally, it will show how costs are being grouped together for presentation purposes.

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M						
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC					
1805	Land		dp	DDCP											
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1805-2	Land Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1806	Land Rights		dp	DDCP											
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1808	Buildings and Fixtures		dp	DDCP											
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1810	Leasehold Improvements		dp	DDCP											
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP12			DCP12				DCP12			DCP12

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4			PNCP4						PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN			CEN							
1825	Storage Battery Equipment		dp	DDCP												
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12					DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP												
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12					BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP					PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS					SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP												
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12					BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP					PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS					SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP												
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12					BCP12			BCP12
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP					PNCP4		PNCP4
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS					SNCP4		SNCP4
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP												
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP12			BCP12					BCP12			BCP12
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x	PNCP4	CCP					PNCP4		PNCP4
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x	SNCP4	CCS					SNCP4		SNCP4
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x	LTNCP4	CCLT					LTNCP4		LTNCP4
1855	Services	Services and Meters	dp			CWCS			CWCS							
1860	Meters	Services and Meters	dp			CWMC			CWMC							

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
1880	IFRS Placeholder Asset Account	IFRS Placeholder Asset Account	dp			0			0							
1905	Land	Land and Buildings	gp							NFA ECC						
1906	Land Rights	Land and Buildings	gp							NFA ECC						
1908	Buildings and Fixtures	General Plant	gp							NFA ECC						
1910	Leasehold Improvements	General Plant	gp							NFA ECC						
1915	Office Furniture and Equipment	Equipment	gp							NFA ECC						
1920	Computer Equipment - Hardware	IT Assets	gp							NFA ECC						
1925	Computer Software	IT Assets	gp							NFA ECC						
1930	Transportation Equipment	Equipment	gp							NFA ECC						
1935	Stores Equipment	Equipment	gp							NFA ECC						
1940	Tools, Shop and Garage Equipment	Equipment	gp							NFA ECC						
1945	Measurement and Testing Equipment	Equipment	gp							NFA ECC						
1950	Power Operated Equipment	Equipment	gp							NFA ECC						
1955	Communication Equipment	Equipment	gp							NFA ECC						
1960	Miscellaneous Equipment	Equipment	gp							NFA ECC						
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp							NFA ECC						
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp							NFA ECC						
1980	System Supervisory Equipment	Other Distribution Assets	gp							NFA ECC						
1990	Other Tangible Property	Other Distribution Assets	gp							NFA ECC						
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout		Break out	Breakout							
2005	Property Under Capital Leases	Other Distribution Assets	gp							NFA ECC						
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp							NFA ECC						
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout							
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout		Break out	Breakout							
3046	Balance Transferred From Income	Equity	NI								NFA					
4080	Distribution Services Revenue	Distribution Services Revenue	CREV													
4080-1	Revenue from Rates	Distribution Services Revenue	CREV								CREV					

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
4080-2	SSS Admin Charge	Other Distribution Revenue	mi								CCA					
4082	Retail Services Revenues	Other Distribution Revenue	mi								OM&A					
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi								OM&A					
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi								OM&A					
4205	Interdepartmental Rents	Other Distribution Revenue	mi								OM&A					
4210	Rent from Electric Property	Other Distribution Revenue	mi								POLE					
4215	Other Utility Operating Income	Other Distribution Revenue	mi								OM&A					
4220	Other Electric Revenues	Other Distribution Revenue	mi								OM&A					
4225	Late Payment Charges	Late Payment Charges	mi								LPHA					
4235	Miscellaneous Service Revenues	Specific Service Charges	mi								CWNB					
4235-1	Account Set Up Charges	Specific Service Charges	mi								CWNB					
4235-90	Miscellaneous Service Revenues - Residual	Specific Service Charges	mi								OM&A					
4240	Provision for Rate Refunds	Other Distribution Revenue	mi								OM&A					
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi								OM&A					
4305	Regulatory Debits	Other Income & Deductions	mi								OM&A					
4310	Regulatory Credits	Other Income & Deductions	mi								OM&A					
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi								OM&A					
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi								OM&A					
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi								OM&A					
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi								OM&A					
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi								OM&A					
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi								OM&A					
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								OM&A					
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi								OM&A					

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi								OM&A					
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi								OM&A					
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi								OM&A					
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi								OM&A					
4375	Revenues from Non-Utility Operations	Other Income & Deductions	mi								OM&A					
4380	Expenses of Non-Utility Operations	Other Income & Deductions	mi								OM&A					
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi								OM&A					
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi								OM&A					
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi								OM&A					
4405	Interest and Dividend Income	Other Income & Deductions	mi								OM&A					
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi								OM&A					
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop							CEN						
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop							CEN EWMP						
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop							CEN						
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop							CEN EWMP						
4750	Charges-LV	Power Supply Expenses (Working Capital)	cop							CEN						
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C		1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C		1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5065	Meter Expense	Operation (Working Capital)	cu			CWMC			CWMC							
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA			CCA							
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA			CCA							
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	1840 & 1845 D	1840 & 1845 C	x	1840 & 1845 D	1840 & 1845 C						1840 & 1845 D	1840 & 1845 D
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	1830 & 1835 D	1830 & 1835 C	x	1830 & 1835 D	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5096	Other Rent	Operation (Working Capital)	di							O&M						

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x	1815-1855 D	1815-1855 C						1815-1855 D	1815-1855 D
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C		1808 D	1808 C						1808 D	1808 D
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C		1815 D	1815 C						1815 D	1815 D
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C		1820 D	1820 C						1820 D	1820 D
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x	1830 D	1830 C						1830 D	1830 D
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x	1835 D	1835 C						1835 D	1835 D
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	1830 & 1835	1830 & 1835 C	x	1830 & 1835	1830 & 1835 C						1830 & 1835 D	1830 & 1835 D
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x	1840 D	1840 C						1840 D	1840 D
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x	1845 D	1845 C						1845 D	1845 D
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C		1855 D	1855 C						1855 D	1855 D
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x	1850 D	1850 C						1850 D	1850 D
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C		1860 D	1860 C						1860 D	1860 D
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB			CWNB							
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR			CWMR							
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB			CWNB							
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB			CWNB							
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB			CWNB							
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB			CWNB							
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA			BDHA							

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB			CWNB							
5405	Supervision	Community Relations (Working Capital)	ad							O&M						
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad							O&M						
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad							O&M						
5420	Community Safety Program	Community Relations (Working Capital)	ad							NFA ECC						
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad							O&M						
5505	Supervision	Other Distribution Expenses	ad							O&M						
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad							O&M						
5515	Advertising Expense	Advertising Expenses	ad							O&M						
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad							O&M						
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M						
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M						
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M						
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad							O&M						
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad							O&M						
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad							O&M						
5635	Property Insurance	Insurance Expense (Working Capital)	ad							NFA ECC						
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad							O&M						
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad							O&M						

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad							O&M						
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad							O&M						
5660	General Advertising Expenses	Advertising Expenses	ad							O&M						
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad							O&M						
5670	Rent	Administrative and General Expenses (Working Capital)	ad							O&M						
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad							O&M						
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad							O&M						
5681	IFRS Placeholder Expense Account	Administrative and General Expenses (Working Capital)	ad							0						
5682	IFRS Placeholder Expense Account	Administrative and General Expenses (Working Capital)	ad							0						
5683	IFRS Placeholder Expense Account	Administrative and General Expenses (Working Capital)	ad							0						
5684	IFRS Placeholder Expense Account	Administrative and General Expenses (Working Capital)	ad							0						
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop							NFA ECC						
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout						PRORATED	PRORATED
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout						PRORATED	PRORATED
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout			Breakout						PRORATED	PRORATED
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout			Breakout						PRORATED	PRORATED
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep							O&M						
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep							O&M						
5740	Amortization of Deferred Charges	Amortization of Assets	dep							O&M						

Uniform System of Accounts - Detail Accounts:					Classification and Allocation			Allocation Demand Related	Allocation Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT							NFA						
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad							NFA						
6110	Income Taxes	Income Tax Expense - Unclassified	Input							NFA						
6205	Donations	Charitable Contributions	ad							O&M						
6210	Life Insurance	Insurance Expense (Working Capital)	ad							O&M						
6215	Penalties	Other Distribution Expenses	ad							O&M						
6225	Other Deductions	Other Distribution Expenses	ad							O&M						

2013 COST ALLOCATION
Enersource Hydro Mississauga
EB-2012-0033
Friday, April 27, 2012
Sheet E5 Reconciliation Worksheet - Run 2

Details:
The worksheet below shows reconciliation of costs included and excluded in the Trial Balance.

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
1565	Conservation and Demand Management Expenditures and Recoveries										
1608	Franchises and Consents										
1805	Land										
1805-1	Land Station >50 kV										
1805-2	Land Station <50 kV										
1806	Land Rights										
1806-1	Land Rights Station >50 kV										
1806-2	Land Rights Station <50 kV										
1808	Buildings and Fixtures										
1808-1	Buildings and Fixtures > 50 kV										
1808-2	Buildings and Fixtures < 50 KV										
1810	Leasehold Improvements										
1810-1	Leasehold Improvements >50 kV										
1810-2	Leasehold Improvements <50 kV										
1815	Transformer Station Equipment - Normally Primary above 50 kV										
1820	Distribution Station Equipment - Normally Primary below 50 kV										
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)										
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)										
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)										
1825	Storage Battery Equipment										
1825-1	Storage Battery Equipment > 50 kV										
1825-2	Storage Battery Equipment <50 kV										
1830	Poles, Towers and Fixtures										
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery										
1830-4	Poles, Towers and Fixtures - Primary										
1830-5	Poles, Towers and Fixtures - Secondary										
1835	Overhead Conductors and Devices										
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery										
1835-4	Overhead Conductors and Devices - Primary										
1835-5	Overhead Conductors and Devices - Secondary										
1840	Underground Conduit										
1840-3	Underground Conduit - Bulk Delivery										
1840-4	Underground Conduit - Primary										
1840-5	Underground Conduit - Secondary										
1845	Underground Conductors and Devices										
1845-3	Underground Conductors and Devices - Bulk Delivery										
1845-4	Underground Conductors and Devices - Primary										
1845-5	Underground Conductors and Devices - Secondary										
1850	Line Transformers										
1855	Services										

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
1860	Meters										
1880	IFRS Placeholder Asset Account										
1905	Land										
1906	Land Rights										
1908	Buildings and Fixtures										
1910	Leasehold Improvements										
1915	Office Furniture and Equipment										
1920	Computer Equipment - Hardware										
1925	Computer Software										
1930	Transportation Equipment										
1935	Stores Equipment										
1940	Tools, Shop and Garage Equipment										
1945	Measurement and Testing Equipment										
1950	Power Operated Equipment										
1955	Communication Equipment										
1960	Miscellaneous Equipment										
1970	Load Management Controls - Customer Premises										
1975	Load Management Controls - Utility Premises										
1980	System Supervisory Equipment										
1990	Other Tangible Property										
1995	Contributions and Grants - Credit										
2005	Property Under Capital Leases										
2010	Electric Plant Purchased or Sold										
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment										
2120	Accumulated Amortization of Electric Utility Plant - Intangibles										
3046	Balance Transferred From Income										
4080	Distribution Services Revenue										
4080-1	Revenue from Rates										
4080-2	SSS Admin Charge										
4082	Retail Services Revenues										
4084	Service Transaction Requests (STR) Revenues										
4090	Electric Services Incidental to Energy Sales										
4205	Interdepartmental Rents										
4210	Rent from Electric Property										
4215	Other Utility Operating Income										
4220	Other Electric Revenues										
4225	Late Payment Charges										
4235	Miscellaneous Service Revenues										
4240	Provision for Rate Refunds										
4245	Government Assistance Directly Credited to Income										
4305	Regulatory Debits										
4310	Regulatory Credits										
4315	Revenues from Electric Plant Leased to Others										
4320	Expenses of Electric Plant Leased to Others										
4325	Revenues from Merchandise, Jobbing, Etc.										
4330	Costs and Expenses of Merchandising, Jobbing, Etc.										
4335	Profits and Losses from Financial Instrument Hedges										
4340	Profits and Losses from Financial Instrument Investments										
4345	Gains from Disposition of Future Use Utility Plant										
4350	Losses from Disposition of Future Use Utility Plant										
4355	Gain on Disposition of Utility and Other Property										

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
4360	Loss on Disposition of Utility and Other Property										
4365	Gains from Disposition of Allowances for Emission										
4370	Losses from Disposition of Allowances for Emission										
4375	Revenues from Non-Utility Operations										
4380	Expenses of Non-Utility Operations										
4390	Miscellaneous Non-Operating Income										
4395	Rate-Payer Benefit Including Interest										
4398	Foreign Exchange Gains and Losses, Including Amortization										
4405	Interest and Dividend Income										
4415	Equity in Earnings of Subsidiary Companies										
4705	Power Purchased										
4708	Charges-WMS										
4710	Cost of Power Adjustments										
4712	Charges-One-Time										
4714	Charges-NW										
4715	System Control and Load Dispatching										
4716	Charges-CN										
4730	Rural Rate Assistance Expense										
4750	Charges-LV										
5005	Operation Supervision and Engineering										
5010	Load Dispatching										
5012	Station Buildings and Fixtures Expense										
5014	Transformer Station Equipment - Operation Labour										
5015	Transformer Station Equipment - Operation Supplies and Expenses										
5016	Distribution Station Equipment - Operation Labour										
5017	Distribution Station Equipment - Operation Supplies and Expenses										
5020	Overhead Distribution Lines and Feeders - Operation Labour										
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses										
5030	Overhead Subtransmission Feeders - Operation										
5035	Overhead Distribution Transformers- Operation										
5040	Underground Distribution Lines and Feeders - Operation Labour										
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses										
5050	Underground Subtransmission Feeders - Operation										
5055	Underground Distribution Transformers - Operation										
5065	Meter Expense										
5070	Customer Premises - Operation Labour										
5075	Customer Premises - Materials and Expenses										
5085	Miscellaneous Distribution Expense										
5090	Underground Distribution Lines and Feeders - Rental Paid										
5095	Overhead Distribution Lines and Feeders - Rental Paid										
5096	Other Rent										
5105	Maintenance Supervision and Engineering										
5110	Maintenance of Buildings and Fixtures - Distribution Stations										
5112	Maintenance of Transformer Station Equipment										

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
5114	Maintenance of Distribution Station Equipment										
5120	Maintenance of Poles, Towers and Fixtures										
5125	Maintenance of Overhead Conductors and Devices										
5130	Maintenance of Overhead Services										
5135	Overhead Distribution Lines and Feeders - Right of Way										
5145	Maintenance of Underground Conduit										
5150	Maintenance of Underground Conductors and Devices										
5155	Maintenance of Underground Services										
5160	Maintenance of Line Transformers										
5175	Maintenance of Meters										
5305	Supervision										
5310	Meter Reading Expense										
5315	Customer Billing										
5320	Collecting										
5325	Collecting- Cash Over and Short										
5330	Collection Charges										
5335	Bad Debt Expense										
5340	Miscellaneous Customer Accounts Expenses										
5405	Supervision										
5410	Community Relations - Sundry										
5415	Energy Conservation										
5420	Community Safety Program										
5425	Miscellaneous Customer Service and Informational Expenses										
5505	Supervision										
5510	Demonstrating and Selling Expense										
5515	Advertising Expense										
5520	Miscellaneous Sales Expense										
5605	Executive Salaries and Expenses										
5610	Management Salaries and Expenses										
5615	General Administrative Salaries and Expenses										
5620	Office Supplies and Expenses										
5625	Administrative Expense Transferred Credit										
5630	Outside Services Employed										
5635	Property Insurance										
5640	Injuries and Damages										
5645	Employee Pensions and Benefits										
5650	Franchise Requirements										
5655	Regulatory Expenses										
5660	General Advertising Expenses										
5665	Miscellaneous General Expenses										
5670	Rent										
5675	Maintenance of General Plant										
5680	Electrical Safety Authority Fees										
5681	IFRS Placeholder Expense Account										
5682	IFRS Placeholder Expense Account										
5683	IFRS Placeholder Expense Account										
5684	IFRS Placeholder Expense Account										
5685	Independent Market Operator Fees and Penalties										
5705	Amortization Expense - Property, Plant, and Equipment										
5710	Amortization of Limited Term Electric Plant										
5715	Amortization of Intangibles and Other Electric Plant										
5720	Amortization of Electric Plant Acquisition Adjustments										
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	$0		$0		$0	$0	$0	$0	$0	$0

USoA Account #	Accounts	Financial Statement	Financial Statement - Asset Break Out includes Acc Dep and Contributed Capital	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
5735											
	Amortization of Deferred Development Costs	$0		$0		$0	$0	$0	$0	$0	$0
5740	Amortization of Deferred Charges	$0		$0		$0	$0	$0	$0	$0	$0
6005	Interest on Long Term Debt	$18,395,000		$18,395,000		$0	$18,395,000	$18,395,000	$0	$18,395,000	$0
6105	Taxes Other Than Income Taxes	$1,200,000		$1,200,000		$0	$1,200,000	$1,200,000	$0	$1,200,000	$0
6110	Income Taxes	$2,981,000		$2,981,000		$0	$2,981,000	$2,981,000	$0	$2,981,000	$0
6205	Donations	$150,000		$150,000		$0	$150,000	$150,000	$0	$150,000	$0
6210	Life Insurance	$0		$0		$0	$0	$0	$0	$0	$0
6215	Penalties	$0		$0		$0	$0	$0	$0	$0	$0
6225	Other Deductions	$0		$0		$0	$0	$0	$0	$0	$0
	Total	**$635,406,988**	**$586,995,056**	**$1,222,402,043**		**$0**	**$1,222,402,043**	**$1,222,402,043**	**$0**	**$1,336,946,697**	**($114,544,654)**
					Control	**$1,222,402,043**					

Grouping by Allocator	Adjusted TB	Excluded from COSS	Excluded	Included	Balance in O5	Difference	Balance in O4 Summary	Difference
1808	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	$ 1,710,989	$ -	$ -	$ 1,710,989	$ 1,710,989	$ -	$ 1,710,989	$ -
1830	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1835	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1840	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1850	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1855	$ 2,679,514	$ -	$ -	$ 2,679,514	$ 2,679,514	$ -	$ 2,679,514	$ -
1860	$ 1,801,916	$ -	$ -	$ 1,801,916	$ 1,801,916	$ -	$ 1,801,916	$ -
1815-1855	$ 7,585,581	$ -	$ -	$ 7,585,581	$ 7,585,581	$ -	$ 7,585,581	$ -
1830 & 1835	$ 2,689,322	$ -	$ -	$ 2,689,322	$ 2,689,322	$ -	$ 2,689,322	$ -
1840 & 1845	$ 3,498,470	$ -	$ -	$ 3,498,470	$ 3,498,470	$ -	$ 3,498,470	$ -
BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BDHA	$ 3,550,000	$ -	$ -	$ 3,550,000	$ 3,550,000	$ -	$ 3,550,000	$ -
Break Out	$ (38,575,023)	$ -	$ -	$ (38,575,023)	$ (38,575,023)	$ -	$ (38,575,023)	$ -
CCA	$ 1,716,475	$ -	$ -	$ 1,716,475	$ 1,716,475	$ -	$ 1,716,475	$ -
CDMPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEN	$ 90,831,798	$ -	$ -	$ 90,831,798	$ 90,831,798	$ -	$ 90,831,798	$ -
CEN EWMP	$ 648,500,146	$ -	$ -	$ 648,500,146	$ 648,500,146	$ -	$ 648,500,146	$ -
CREV	$ (114,544,654)	$ -	$ -	$ (114,544,654)	$ (114,544,654)	$ -	$ -	$ (114,544,654)
CWCS	$ 15,157,937	$ -	$ -	$ 15,157,937	$ 15,157,937	$ -	$ 15,157,937	$ -
CWMC	$ 39,022,351	$ -	$ -	$ 39,022,351	$ 39,022,351	$ -	$ 39,022,351	$ -
CWMR	$ 24,000	$ -	$ -	$ 24,000	$ 24,000	$ -	$ 24,000	$ -
CWNB	$ 7,480,391	$ -	$ -	$ 7,480,391	$ 7,480,391	$ -	$ 7,480,391	$ -
DCP	$ 35,768,173	$ -	$ -	$ 35,768,173	$ 35,768,173	$ -	$ 35,768,173	$ -
LPHA	$ (1,800,000)	$ -	$ -	$ (1,800,000)	$ (1,800,000)	$ -	$ (1,800,000)	$ -
LTNCP	$ 57,276,606	$ -	$ -	$ 57,276,606	$ 57,276,606	$ -	$ 57,276,606	$ -
NFA	$ (1,357,092)	$ -	$ -	$ (1,357,092)	$ (1,357,092)	$ -	$ (1,357,092)	$ -
NFA ECC	$ 72,332,531	$ -	$ -	$ 72,332,531	$ 72,332,531	$ -	$ 72,332,531	$ -
O&M	$ 25,196,495	$ -	$ -	$ 25,196,495	$ 25,196,495	$ -	$ 25,196,495	$ -
PNCP	$ 283,226,996	$ -	$ -	$ 283,226,996	$ 283,226,996	$ -	$ 283,226,996	$ -
SNCP	$ 79,165,085	$ -	$ -	$ 79,165,085	$ 79,165,085	$ -	$ 79,165,085	$ -
TCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	**$ 1,222,938,007**	**$ -**	**$ -**	**$ 1,222,938,007**	**$ 1,222,938,007**	**$ -**	**$ 1,337,482,661**	**$ (114,544,654)**

Appendix 2-O
Cost Allocation

Enersource Mississauga Hydro's previous Cost Allocation was the 2008 Cost of Service Application.

a) Allocated Costs

Small Commercial and Unmetered Scatter Load (UMSL) were combined into one rate class in the previous Cost Allocation Study. For purposes of comparison the combined total from previous study is split based on the number of customer accounts.

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	%
Residential	$ 46,484,474	41.3%	$ 59,831,168	44.6%
Small commercial*	$ 225,746	0.2%	$ -	0.0%
GS < 50 kW	$ 14,982,784	13.3%	$ 16,549,924	12.3%
GS > 50 kW	$ 27,222,124	24.2%	$ 30,328,404	22.6%
GS > 500 kW	$ 16,965,654	15.1%	$ 19,851,007	14.8%
Large User, if applicable	$ 4,202,131	3.7%	$ 5,475,286	4.1%
Street Lighting	$ 2,123,429	1.9%	$ 1,615,703	1.2%
UMSL	$ 448,123	0.4%	$ 465,398	0.3%
Total	$ 112,654,465	100.0%	$ 134,116,890	100.0%

Table a) Allocated Costs is restated below to reflect the changes in the rate classes - Small Commercial rate class is to be retired, current small commercial customers will migrate to GS < 50 kW, Unmetered Scattered Load will be split out from the formerly combined Small Commercial UMSL.

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	%
Residential	$ 46,484,474	41.3%	$ 59,831,168	44.6%
GS < 50 kW	$ 15,208,530	13.5%	$ 16,549,924	12.3%
GS > 50 kW	$ 27,222,124	24.2%	$ 30,328,404	22.6%
GS > 500 kW	$ 16,965,654	15.1%	$ 19,851,007	14.8%
Large User, if applicable	$ 4,202,131	3.7%	$ 5,475,286	4.1%
Street Lighting	$ 2,123,429	1.9%	$ 1,615,703	1.2%
UMSL	$ 448,123	0.4%	$ 465,398	0.3%
Total	$ 112,654,465	100.0%	$ 134,116,890	100.0%

b) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	LF X current approved rates X (1 + 12.87%)	LF X proposed rates	Miscellaneous Revenue
Residential	$ 43,770,787	$ 49,404,337	$ 50,896,278	$ 2,683,366
GS < 50 kW	$ 15,747,527	$ 17,774,324	$ 17,352,075	$ 795,011
GS > 50 kW	$ 29,001,515	$ 32,734,175	$ 32,413,984	$ 814,417
GS > 500 kW	$ 18,250,501	$ 20,599,445	$ 20,646,100	$ 426,622
Large User, if applicable	$ 5,878,883	$ 6,635,529	$ 5,990,619	$ 49,325
Street Lighting	$ 1,315,572	$ 1,484,893	$ 1,491,382	$ 44,131
UMSL	$ 579,869	$ 654,501	$ 496,766	$ 16,813
Total	$ 114,544,654	$ 129,287,204	$ 129,287,204	$ 4,829,685

c) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2008	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	92	87	90	85 - 115
GS < 50 kW	111	112	110	80 - 120
GS > 50 kW	111	111	110	80 - 120
GS > 500 kW	92	106	106	85 - 115
Large User, if applicable	111	122	110	70 - 120
Street Lighting	92	95	95	80 - 120
UMSL	111	144	110	80 - 120

Fixed/Variable Proportion

This exhibit explains how the proposed 2013 Test Year and 2014 ICR Year rates have been designed in order to collect the requested revenue requirements. The proposed Tariff of Rates and Charges for the 2013 Test Year and the 2014 ICR Year are provided in Exhibit 8 Tab 8 Schedule 1 Appendix 1 and Appendix 2, respectively. The 2012 Tariff of Rates and Charges will be provided in Exhibit 8 Tab 1 Schedule 1 Appendix 3, once approved[1].

Enersource is requesting approval of a 2013 Test Year base revenue requirement of $129,287 and a transformer ownership credit of $1,998 for a total revenue requirement of $131,285 from distribution rates. It is proposed that this revenue requirement be collected from the customer classes in similar percentages as the current rates, except for the adjustments made as a result of the cost allocation study, detailed in Exhibit 7 Tab 1 Schedule 1.

Enersource is proposing an adjustment to its rate classes. Enersource currently has no separate Unmetered Scattered Loads ("USL") rate class, as the USL customers are included as part of the Small Commercial rate class. A new USL rate class has been included in the Cost Allocation Model and proposed Tariff of Rates and Charges. Enersource is proposing to merge the Small Commercial less than 50 kW rate class with the General Service less than 50 kW rate class. These customers are not sufficiently different in service setup, billing, collections, and meter reading profiles to require a separate rate class.

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[1] EB-2011-0100 Decision issued on April 19, 2012. The corresponding Final Rate Order has not been approved as of the date of filing this Application. Appendix 3 will be filed once the Final Rate Order in EB-2011-0100 is approved.

Table 1 below provides the revenue per rate class using the current rates, the calculated rates based on the revenue deficiency, and the proposed rates using the 2013 forecasted load and customers/connections/devices.

Table 1: 2013 Revenue per Rate Class

	A	B	C	D	E	F
	Distribution Revenue with Current Rates[2] $000s	**%**	**2013 Distribution Revenue with Initial Rates before Cost Allocation $000s**	**%**	**2013 Distribution Revenue after Cost Allocation $000s**	**%**
Residential	$ 43,771	37.6%	$ 49,308	37.6%	$ 51,683	39.4%
General Service < 50 kW [1]	$ 15,748	13.5%	$ 17,740	13.5%	$ 17,620	13.4%
Unmetered Scattered Load	$ 580	0.5%	$ 653	0.5%	$ 504	0.4%
General Service 50 kW - 499 kW	$ 29,171	25.0%	$ 32,862	25.0%	$ 32,915	25.1%
General Service 500 kW - 4999 kW	$ 19,384	16.6%	$ 21,836	16.6%	$ 20,965	16.0%
Large Use (> 5000 kW)	$ 6,574	5.6%	$ 7,405	5.6%	$ 6,083	4.6%
Street Lighting	$ 1,316	1.1%	$ 1,482	1.1%	$ 1,514	1.2%
Total Revenue to Recover in Rates[3]	$ 116,543	100.0%	$ 131,285	100.0%	$ 131,285	100.0%

[1] Columns C to F include the current small commercial class as part of GS < 50 kW

[2] Includes 2012 Smart Meter Funding Adder

[3] Includes Transformer Ownership Allowance revenue requirement

Table 2 and Table 3 detail the current monthly fixed and volumetric distribution rates, the 2013 calculated monthly fixed and volumetric rates based on the revenue deficiency before cost allocation adjustments, and the 2013 proposed monthly fixed and volumetric rates after applying cost allocation adjustments.

Table 2: Distribution Fixed Rates, 2012 and 2013

	A	B	C
	2012 $/month[2]	2013 before Cost Allocation adjustments $/month	2013 after Cost Allocation adjustments $/month
Residential	$ 12.64	$ 14.24	$ 14.70
General Service < 50 kW [1]	$ 40.70	$ 45.85	$ 44.68
Unmetered Scattered Load	$ 10.69	$ 12.04	$ 9.16
General Service 50 kW - 499 kW	$ 70.63	$ 79.56	$ 78.48
General Service 500 kW - 4999 kW	$ 1,539.04	$ 1,733.73	$ 1,639.27
Large Use (> 5000 kW)	$ 13,857.67	$ 15,610.65	$ 12,628.34
Street Lighting	$ 1.34	$ 1.51	$ 1.52

[1] Columns B to C include the current small commercial class as part of GS < 50 kW

[2] Includes 2012 Smart Meter Funding Adder

Table 3: Distribution Volumetric Rates, 2012 and 2013

		A	B	C
		2012 $/kWh or $/kW	2013 before Cost Allocation adjustments $/kWh or $/kW	2013 after Cost Allocation adjustments $/kWh or $/kW
Residential	kWh	$ 0.0119	$ 0.0134	$ 0.0144
General Service < 50 kW [1]	kWh	$ 0.0116	$ 0.0131	$ 0.0133
Unmetered Scattered Load	kWh	$ 0.0195	$ 0.0220	$ 0.0174
General Service 50 kW - 499 kW	kW	$ 4.2044	$ 4.7363	$ 4.7533
General Service 500 kW - 4999 kW	kW	$ 2.0981	$ 2.3635	$ 2.2966
Large Use (> 5000 kW)	kW	$ 2.9225	$ 3.2922	$ 2.7165
Street Lighting	kW	$ 10.2587	$ 11.5564	$ 12.0916

Enersource is not proposing to adjust the fixed/variable split for each class. Table 4 provides the fixed/variable split for each class after the adjustments for cost allocation.

Table 4: Proposed 2013 Fixed/Variable Split

	A	B	C	D	E
	Fixed $000s	**%**	**Variable $000s**	**%**	**Total $000**
Residential	$ 31,194	60.4%	$ 20,489	39.6%	$ 51,683
General Service < 50 kW [1]	$ 9,492	53.9%	$ 8,128	46.1%	$ 17,620
Unmetered Scattered Load	$ 323	64.1%	$ 181	35.9%	$ 504
General Service 50 kW - 499 kW	$ 3,720	11.3%	$ 29,195	88.7%	$ 32,915
General Service 500 kW - 4999 kW	$ 9,127	43.5%	$ 11,838	56.5%	$ 20,965
Large Use (> 5000 kW)	$ 1,364	22.4%	$ 4,719	77.6%	$ 6,083
Street Lighting	$ 911	60.2%	$ 603	39.8%	$ 1,514
TOTAL	$ 56,132	42.8%	$ 75,153	57.2%	$ 131,285

[1] Columns C to E include small commercial as part of GS < 50 kW

Enersource is proposing to maintain the same monthly fixed rates for standby charges and for microFIT.

Standby charges consist of a monthly fixed charge of $200 for simple metering arrangements, or $500 for complex metering arrangements where Enersource provides distribution service on a standby basis as a back-up supply to an on-site generator.

Enersource currently uses the province-wide microFIT rate of $5.25 per month per customer and proposes to continue charging this rate as reflected in the Proposed Tariff of Rates and Charges found at Appendix 1 of this exhibit.

As required in the OEB's Report of the Board on the Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219), Table 5 below provides

information on the cost elements identified in the Board's EB-2009-0326 Decision and Order.

Table 5: MicroFIT Cost Elements

#	Cost Element Name	USoA	$	Monthly Unit Cost
1	Customer Premises - Operations Labour	5070	$1,354,596.80	$ 0.64
2	Customer Premises - Materials and Expenses	5075	$ 71,921.15	$ 0.03
3	Meter Expenses	5065	$ 604,740.90	$ 0.28
4	Maintenance of Meters	5175	$1,082,580.83	$ 0.51
5	Meter Reading Expenses	5310	$ 13,245.41	$ 0.01
6	Customer Billing	5315	$2,422,213.01	$ 1.14
7	Amortization Expense - General Plant Assigned to Meters		$ 333,402.82	$ 0.16
8	Admin and General Expenses allocated to O&M expenses for meters		$1,300,313.64	$ 0.61
9	Allocated PILS (general plant assigned to meters)		$ 13,282.73	$ 0.01
10	Interest Expense		$ 81,964.39	$ 0.04
11	Income Expenses		$ 101,899.12	$ 0.05
	Total Cost		$7,380,160.81	$ 3.48
	Number of Residential Customers		176,865	

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	14.70
Stranded Conventional Meters Disposition Rate Rider - effective until December 31, 2013	$	3.23
Smart Meter Disposition Rate Rider - effective until December 31, 2013	$	0.13
Distribution Volumetric Rate	$/kWh	0.0144
Rate Rider for Deferral/Variance Account Disposition - effective until April 30, 2013	$/kWh	-0.0003
Rate Rider for Deferral/Variance Account Disposition - effective until December 31, 2013	$/kWh	-0.0035
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kWh	-0.0011
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective Until April 30, 2013	$/kWh	0.0003
Low Voltage Service Rate	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0057
Rate Rider for Global Adjustment Sub-Account Disposition - effective until December 31, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0005
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0022

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	44.68
Stranded Conventional Meters Disposition Rate Rider - effective until December 31, 2013	$	3.40
Smart Meter Disposition Rate Rider - effective until December 31, 2013	$	0.13
Distribution Volumetric Rate	$/kWh	0.0133
Rate Rider for Deferral/Variance Account Disposition - effective until April 30, 2013	$/kWh	-0.0003
Rate Rider for Deferral/Variance Account Disposition - effective until December 31, 2013	$/kWh	-0.0033
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kWh	-0.0011
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective Until April 30, 2013	$/kWh	0.0002
Low Voltage Service Rate	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052
Rate Rider for Global Adjustment Sub-Account Disposition - effective until December 31, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0005
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0022

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

UNMETERED SCATTERED LOAD - PER CONNECTION SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer and will be agreed to by Enersource Hydro Mississauga Inc. and the customer and may be subject to periodic monitoring of actual consumption. Eligible unmetered loads include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge for Unmetered Scattered Load account (per connection)	$	9.16
Distribution Volumetric Rate	$/kWh	0.0174
Rate Rider for Deferral/Variance Account Disposition - effective until April 30, 2013	$/kWh	-0.0006
Rate Rider for Deferral/Variance Account Disposition - effective until December 31, 2013	$/kWh	-0.0057
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kWh	-0.0012
Low Voltage Service Rate	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052
Rate Rider for Global Adjustment Sub-Account Disposition - effective until December 31, 2013 Applicable only for Non-RPP Customers	$/kWh	0.0004
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0022

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Notwithstanding the tariff of rates and charges listed below, the provisions of individually negotiated contracts with certain large use customers will prevail. Also, Enersource establishes billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	78.48
Stranded Conventional Meters Disposition Rate Rider - effective until December 31, 2013	$	1.22
Smart Meter Disposition Rate Rider - effective until December 31, 2013	$	0.13
Distribution Volumetric Rate	$/kW	4.7533
Rate Rider for Deferral/Variance Account Disposition - effective until April 30, 2013	$/kW	-0.0546
Rate Rider for Deferral/Variance Account Disposition - effective until December 31, 2013	$/kW	-0.7170
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.3693
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective Until April 30, 2013	$/kW	0.0281
Low Voltage Service Rate	$/kW	0.0805
Retail Transmission Rate – Network Service Rate	$/kW	2.6160
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.6160
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0283
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0283
Rate Rider for Global Adjustment Sub-Account Disposition - effective until December 31, 2013		
Applicable only for Non-RPP Customers	$/kW	0.1365
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014		
Applicable only for Non-RPP Customers	$/kW	-0.7339

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Notwithstanding the tariff of rates and charges listed below, the provisions of individually negotiated contracts with certain large use customers will prevail. Also, Enersource establishes billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1,639.27
Distribution Volumetric Rate	$/kW	2.2966
Rate Rider for Deferral/Variance Account Disposition - effective until April 30, 2013	$/kW	-0.0471
Rate Rider for Deferral/Variance Account Disposition - effective until December 31, 2013	$/kW	-0.6377
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.4696
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective Until April 30, 2013	$/kW	0.0111
Low Voltage Service Rate	$/kW	0.0788
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5309
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9847
Rate Rider for Global Adjustment Sub-Account Disposition - effective until December 31, 2013 Applicable only for Non-RPP Customers	$/kW	0.1740
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	-0.9425

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

LARGE USE > 5000 KW SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Notwithstanding the tariff of rates and charges listed below, the provisions of individually negotiated contracts with certain large use customers will prevail. Also, Enersource establishes billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12,628.34
Distribution Volumetric Rate	$/kW	2.7165
Rate Rider for Deferral/Variance Account Disposition - effective until April 30, 2013	$/kW	-0.0465
Rate Rider for Deferral/Variance Account Disposition - effective until December 31, 2013	$/kW	-0.7701
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.6324
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery - effective Until April 30, 2013	$/kW	0.0035
Low Voltage Service Rate	$/kW	0.0841
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7007
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1197
Rate Rider for Global Adjustment Sub-Account Disposition - effective until December 31, 2013 Applicable only for Non-RPP Customers	$/kW	0.2306
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	-1.2714

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

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EB-2012-0033

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. Street Lighting is unmetered where energy consumption is estimated based on the connected wattage and calculated hours of use using methods established by the Ontario Energy Board. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION
The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per luminaire)	$	1.52
Distribution Volumetric Rate	$/kW	12.0916
Rate Rider for Deferral/Variance Account Disposition - effective until April 30, 2013	$/kW	-0.1837
Rate Rider for Deferral/Variance Account Disposition - effective until December 31, 2013	$/kW	-1.8174
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.3874
Low Voltage Service Rate	$/kW	0.0582
Retail Transmission Rate – Network Service Rate	$/kW	1.8116
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4666
Rate Rider for Global Adjustment Sub-Account Disposition - effective until December 31, 2013 Applicable only for Non-RPP Customers	$/kW	0.1422
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	-0.7714

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date January 1, 2013

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EB-2012-0033

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be notedthat this schedule does not list any charges, assessments, or credits that are required by law to beinvoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Programs, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2013
Implementation Date January 1, 2013

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EB-2012-0033

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.40)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$ 15.00
Request for other billing information	$ 15.00
Credit reference/credit check (plus credit agency costs)	$ 15.00
Credit reference/credit check (plus credit agency costs - General Service)	$ 25.00
Income tax letter	$ 15.00
Returned cheque charge (plus bank charges)	$ 12.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable - Residential)	$ 20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ 10.00
Special meter reads	$ 30.00
Interval meter request change	$ 40.00

Non-Payment of Account

Late Payment - per month	% 1.50
Late Payment - per annum	% 19.56
Collection of account charge - no disconnection	$ 9.00
Disconnect/Reconnect at meter - during regular hours	$ 20.00
Disconnect/Reconnect at pole - during regular hours	$ 185.00
Disconnect/Reconnect at pole - after regular hours	$ 415.00
Temporary service install & remove - overhead - no transformer	$ 400.00
Specific Charge for Access to the Power Poles - per pole/year	$ 22.35

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES
Effective Date January 1, 2013
Implementation Date January 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0360
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0256
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2014
Implementation Date January 1, 2014

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EB-2012-0033

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	15.06
Distribution Volumetric Rate	$/kWh	0.0147
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kWh	-0.0011
Low Voltage Service Rate	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0073
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0057
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0022

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2014
Implementation Date January 1, 2014

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EB-2012-0033

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	45.77
Distribution Volumetric Rate	$/kWh	0.0136
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kWh	-0.0011
Low Voltage Service Rate	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0022

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2014
Implementation Date January 1, 2014

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EB-2012-0033

UNMETERED SCATTERED LOAD - PER CONNECTION SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer and will be agreed to by Enersource Hydro Mississauga Inc. and the customer and may be subject to periodic monitoring of actual consumption. Eligible unmetered loads include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge for Unmetered Scattered Load account (per connection)	$	9.38
Distribution Volumetric Rate	$/kWh	0.0179
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kWh	-0.0012
Low Voltage Service Rate	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0068
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kWh	-0.0022

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2014
Implementation Date January 1, 2014

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EB-2012-0033

GENERAL SERVICE 50 TO 499 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Notwithstanding the tariff of rates and charges listed below, the provisions of individually negotiated contracts with certain large use customers will prevail. Also, Enersource establishes billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	80.39
Distribution Volumetric Rate	$/kW	4.8688
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.3693
Low Voltage Service Rate	$/kW	0.0805
Retail Transmission Rate – Network Service Rate	$/kW	2.6160
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.6160
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0283
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0283
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	-0.7339

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2014
Implementation Date January 1, 2014

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GENERAL SERVICE 500 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Notwithstanding the tariff of rates and charges listed below, the provisions of individually negotiated contracts with certain large use customers will prevail. Also, Enersource establishes billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	1,679.12
Distribution Volumetric Rate	$/kW	2.3524
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.4696
Low Voltage Service Rate	$/kW	0.0788
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5309
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9847
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	-0.9425

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2014
Implementation Date January 1, 2014

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EB-2012-0033

LARGE USE > 5000 KW SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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Notwithstanding the tariff of rates and charges listed below, the provisions of individually negotiated contracts with certain large use customers will prevail. Also, Enersource establishes billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	12,935.32
Distribution Volumetric Rate	$/kW	2.7825
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.6324
Low Voltage Service Rate	$/kW	0.0841
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7007
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.1197
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	-1.2714

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date January 1, 2014
Implementation Date January 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting. Street Lighting is unmetered where energy consumption is estimated based on the connected wattage and calculated hours of use using methods established by the Ontario Energy Board. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION
The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per luminaire)	$	1.56
Distribution Volumetric Rate	$/kW	12.3855
Rate Rider for Deferral/Variance Account Disposition - effective until January 31, 2014	$/kW	-0.3874
Low Voltage Service Rate	$/kW	0.0582
Retail Transmission Rate – Network Service Rate	$/kW	1.8116
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4666
Rate Rider for Global Adjustment Sub-Account Disposition - effective until January 31, 2014 Applicable only for Non-RPP Customers	$/kW	-0.7714

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES
Effective Date January 1, 2014
Implementation Date January 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be notedthat this schedule does not list any charges, assessments, or credits that are required by law to beinvoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Programs, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.25

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES
Effective Date January 1, 2014
Implementation Date January 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0033

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.40)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$ 15.00
Request for other billing information	$ 15.00
Credit reference/credit check (plus credit agency costs)	$ 15.00
Credit reference/credit check (plus credit agency costs - General Service)	$ 25.00
Income tax letter	$ 15.00
Returned cheque charge (plus bank charges)	$ 12.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$ 30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable - Residential)	$ 20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$ 10.00
Special meter reads	$ 30.00
Interval meter request change	$ 40.00

Non-Payment of Account

Late Payment - per month	% 1.50
Late Payment - per annum	% 19.56
Collection of account charge - no disconnection	$ 9.00
Disconnect/Reconnect at meter - during regular hours	$ 20.00
Disconnect/Reconnect at pole - during regular hours	$ 185.00
Disconnect/Reconnect at pole - after regular hours	$ 415.00
Temporary service install & remove - overhead - no transformer	$ 400.00
Specific Charge for Access to the Power Poles - per pole/year	$ 22.35

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES
Effective Date January 1, 2014
Implementation Date January 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0360
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0256
Distribution Loss Factor - Primary Metered Customer > 5,000 kW	1.0045

Enersource Hydro Mississauga Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2012
Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0100

Decision received April 19, 2012. To be filed once Final Rate Order is approved.

Retail Transmission Service Rates

On June 22, 2011, the Board issued a revision to Guideline G-2008-0001 – *Electricity Distribution Retail Transmission Service Rates* (the "Guideline"), which outlined information that the Board requires electricity distributors to file to adjust their retail transmission service rates ("RTSR") for 2011. The Guideline and filing module have not been updated for 2013 rates.

Current RTSR

On December 20, 2011, the Board issued the *Revenue Requirement Order Arising from the EB-2011-0268 Decision with Reasons (November 23, 2011) and 2012 Uniform Electricity Transmission Rate Order*[1]. This was a Hydro One Networks Inc. proceeding.

This Board Order set new transmission rates effective January 1, 2012. These rates are shown below in Table 1.

Table 1: Wholesale Transmission Rates, Effective January 1, 2012

	Current
Network Service Rate	$3.57/kW
Line Connection Service Rate	$0.80/kW
Transformation Connection Service Rate	$1.86/kW

As part of the above rate change, Enersource's current RTSR rates, effective May 1, 2012, are reflected in Table 2 below.

[1] EB-2011-0268

Table 2: Current Retail Transmission Service Rates

Customer Class	Unit	Network Service Rate	Line and Transformation Connection Service Rate
Residential	kWh	$0.0073	$0.0057
GS < 50 kW	kWh	$0.0068	$0.0052
Unmetered Scattered Load	kWh	$0.0068	$0.0052
GS 50-499 kW	kW	$2.6160	$2.0283
GS 500-4999 kW	kW	$2.5309	$1.9847
Large Use	kW	$2.7007	$2.1197
Street lighting	kW	$1.8116	$1.4666

Variance Accounts

Table 3 below shows the wholesale costs and retail revenue amounts for network and connection activities from 2009 to 2011.

Table 3: Wholesale Network and Connection Costs and Retail Revenue ($000s)

	2009	2010	2011	Total
Network - Costs	36,366	42,762	46,385	125,514
Network - Revenue	(39,601)	(45,740)	(45,885)	(131,226)
Contribution to Network Variance Account	(3,235)	(2,977)	500	(5,712)
Connection - Costs	33,785	36,467	38,461	108,713
Connection - Revenue	(36,493)	(39,052)	(38,008)	(113,553)
Contribution to Connection Variance Account	(2,709)	(2,585)	453	(4,840)

Enersource received Board approval to refund the December 31, 2010 balances to customers effective February 1, 2012. As part of this Application, Enersource is proposing to dispose of the December 31, 2011 balances, via rate riders, as identified in Exhibit 9 Tab 1 Schedule 1.

2013 RTSR

Enersource is not seeking to adjust its RTSR at this time. Enersource proposes to update its request for 2013 RTSR when the Board issues the updated Guideline and filing module to reflect the January 1, 2013 Uniform Transmission Rates.

Retail Service Charges

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

The OEB has established variance accounts (1518 Retail Cost Variance Retail - RCVA $_{Retail}$ and 1548 Retail Cost Variance STR – RCVA $_{STR}$) to record the difference between the amount billed and the incremental costs of providing retail services. Enersource does not propose any changes to the current retail rates and charges. Table 1 provides details regarding these current approved retail rates and charges. Further details related to revenue generated from retailer rates and charges can be found in Exhibit 3 Tab 3 Schedule 1.

Table 1: Current Retail Service Charges

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100
Monthly Fixed Charge, per retailer	$	20
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

RCVA costs are tracked separately and included in Exhibit 4 Tab 1 Schedule 13. These include costs related to entering into service agreements with retailers, and related contract administration, monitoring, and other expenses necessary to maintain the contract, as well as the incremental costs of labour and benefits, internal information system maintenance costs, and delivery costs related to the provision of retailer services.

Tables 2 and 3 below show the Retail Cost Variance Accounts for 2008 to 2011. As part of the Application, Enersource is proposing to dispose of the December 31, 2011 balances, via rate riders, as identified in Exhibit 9 Tab 1 Schedule 1.

For the purposes of this Application, Enersource has assumed that the total retailer service revenue is completely offset by operating costs related to servicing retailer operations and third-party costs from the operator of the retailer transaction hub.

Table 2: Account 1518 - Retail Cost Variance ($000s)

	2007	2008	2009	2010	2011	Total
Retail Cost Variance Cost	313	310	302	392	392	1709
Retail Cost Variance Revenue	(306)	(298)	(293)	(279)	(237)	(1,413)
Contribution to Variance Account	7	12	9	113	155	296

Table 3: Account 1548 - Retail Cost Variance Service Transaction Request ($000s)

	2007	2008	2009	2010	2011	Total
Retail Cost Variance STR Revenue	99	83	51	74	74	381
Retail Cost Variance STR Cost	(22)	(13)	(10)	(13)	(7)	(65)
Contribution to Variance Account	77	70	41	61	67	316

Wholesale Market Service Rate

On December 21, 2011, the Board issued a Decision with Reasons and Rate Order (EB-2011-0405) establishing the Remote and Rural Rate Protection ("RRRP") charge for 2012. The Board amended the RRRP charge to be collected by the Independent Electricity System Operator ("IESO") from the current $0.0013 per kWh to $0.0011 per kWh effective May 1, 2012.

The Board has also determined that, given the change in the RRRP charge that the IESO will use to invoice distributors effective May 1, 2012, it will also be necessary to reflect the same change in the RRRP charge that all regulated distributors use to bill their customers effective May 1, 2012. This will ensure that amounts paid to the IESO by each distributor are recovered from the customers of the distributor.

Current Wholesale Market Service Rate and RRRP

The current Wholesale Market Service Rate and RRRP charge are shown in Table 1 below.

Table 1: Current Wholesale Market Service Rate and RRRP Charge)

		Current
Wholesale Market Service Rate	$/kWh	$0.0052
Rural Rate Protection Charge	$/kWh	$0.0011
Total	$/kWh	$0.0063

Variance Accounts

Table 2 below shows the wholesale market service costs and revenue amounts from 2009 to 2011.

Table 2: Wholesale Market Service Costs and Revenue ($000s)

	2009	2010	2011	Total
Wholesale Market Service Costs	47,422	43,510	43,407	134,339
Wholesale Market Service Revenue	(49,572)	(51,760)	(51,210)	(152,543)
Contribution to Variance Account	(2,151)	(8,251)	(7,803)	(18,204)

Enersource received Board approval to refund the December 31, 2010 balances to customers effective February 1, 2012. As part of this Application, Enersource is proposing to dispose of the December 31, 2011 balances, via rate riders, as identified in Exhibit 9 Tab 1.

Proposed 2013 Wholesale Market Service Rate and RRRP

Enersource is not seeking to adjust the Wholesale Market Service Rate or RRRP in this Application.

Specific Service Charges

Enersource is not requesting any new specific service charges or proposing to make any changes to existing service charges in this Application. Details of existing service charges are found at Exhibit 3 Tab 3 Schedule 1 Appendix 2.

Low Voltage Service Rates

Enersource receives low voltage ("LV") charges from Hydro One Networks Inc. ("Hydro One") for a number of shared distribution stations, specific lines, and shared lines.

In a June 13, 2006 memo, the Board notified distributors that Account 4750, Charges – LV, Account 4075, Billed – LV, and Account 1550 – LV Variance Account had been added to the Uniform System of Accounts ("USofA"). As a result, effective May 1, 2006 Account 1550 has been used to record the net of the amounts recorded in Accounts 4750 (amount charged by Hydro One for low voltage services) and 4075 (amount customers are billed for low voltage services).

Furthermore, in October, 2009, the Board released its "Frequently Asked Questions" which addressed the charges from Hydro One related to the new sub-transmission and regulatory assets implemented on February 1, 2009 (per Rate Order EB-2007-0681). In this rate order, two new charges in the "Tariff of Rates and Charges" were approved, in the form of a new service charge to be applied to each delivery point including a smart meter charge and a new facility charge for connection to common ST lines, and a regulatory asset recovery charge. As a result of these new charges, LV charges have increased as reflected in Table 1 below from 2009 to 2011.

Proposed LV Charges for 2013

Enersource currently records all costs related to LV to account 1550 and is proposing to create an LV rate to recover Hydro One's LV charges to Enersource from customers for the 2013 Test Year. The revenue generated from this new LV rate will be recorded to account 1550 to offset the Hydro One LV charges that are currently recorded in the same account.

Table 1 below shows the forecasted LV charges for 2012 and 2013. Enersource requests approval to create a new rate equal to the 2012 and 2013 forecasted LV charge.

Table 1: LV Charges, 2009 to 2013 ($000s)

	2009	2010	2011	Forecast 2012	Forecast 2013
Low Voltage Charges	861	1,139	1,493	1,500	1,500

The LV charge has been allocated to the customer classes based on the class percentage of retail transmission connection amounts (using 2012 rates), as shown in Table 2 below. This is the same methodology used in the 2006 Electricity Distribution Rate Handbook.

Table 2: Calculation of LV Rates

		2013 Retail Transmission Connection Rate ($)	2013 Charge Determinant	A * B Basis for Allocation	Allocation %	Allocation ($)	Rate
Residential	kWh	0.0057	1,423,857,475	8,115,988	21.47%	322,091	0.0002
General Service < 50 kW	kWh	0.0052	612,188,101	3,183,378	8.42%	126,336	0.0002
Unmetered Scattered Load	kWh	0.0052	10,383,027	53,992	0.14%	2,143	0.0002
General Service 50 kW - 499 kW	kW	2.0283	6,142,022	12,457,863	32.96%	494,403	0.0805
General Service 500 kW - 4999 kW	kW	1.9847	5,154,338	10,229,815	27.07%	405,981	0.0788
Large Use (> 5000 kW)	kW	2.1197	1,737,267	3,682,484	9.74%	146,143	0.0841
Street Lighting	kW	1.4666	49,889	73,167	0.19%	2,904	0.0582
Total				37,796,687	100.00%	1,500,000	

Distribution System Loss Adjustment Factors

Overview

Distribution system losses and the resulting loss factor ("Loss Factor") are computed as the difference between the energy Enersource receives from Hydro One's transmission grid and the recorded energy delivered to customers. The Loss Factor is applied to a customer's meter consumption for billing purposes. The resulting billed consumption reflects the amount of electricity Enersource has to purchase in order to supply each customer on the system, taking into account the distribution system losses.

The distribution system losses can be divided into two main categories: non-technical and technical losses. The non-technical losses occur from:

- unmetered loads;
- power theft;
- billing errors; and
- meter reading errors.

The non-technical losses are described below.

Unmetered Loads

Enersource delivers electricity to numerous unmetered loads throughout its service area including: photo-electric controlled loads such as street lights, bus shelters, and bill boards; and other loads such as cathodic protection devices, telecommunication junction boxes, and rotating bill boards.

Enersource maintains data on the name plate ratings of the unmetered loads. This data is used in conjunction with data on the frequency and duration of supply to support estimates of the energy and power required by these loads. This data serves as a proxy of the true load and is used for billing purposes. For example, photo-electric controlled loads have a known number of devices, each with a specific wattage, that can be relied on to calculate the demand of the unit. This demand is multiplied by the number of hours of operation according to the estimated number of daylight hours, and varies by month. Daily consumption is calculated and is used to determine the monthly consumption. This method is generally applied to non-photoelectric controlled loads, except that the hours of operation are estimated using device specific data.

Power Theft

To find possible power theft installations, Enersource has requested meter readers to look for evidence of theft when the meters are read on individual sites. In addition, since the vast majority of residents in Mississauga are now metered by smart meters, Enersource looks at the billing information from smart meters to flag suspicious power consumption patterns. This assists with locating possible power theft sites, and discovering potential issues with the metering equipment.

Technical Losses

Technical losses are principally due to:

- internal resistance of cables and conductors;
- winding resistance and magnetic field fluctuations in transformers; and
- meters.

The following equipment categories are identified as main contributors to the technical distribution system losses, and are described below:

- municipal stations;
- primary lines;
- distribution transformers; and
- secondary lines.

Primary Lines

The most significant amount of the technical losses from the above four categories arises on primary lines. Primary lines distribute power from transformer stations to distribution transformers. The losses in the primary lines are directly proportional to the length and loading of the lines. To minimize the technical losses, Enersource reviews the entire system every year and identifies areas where the feeders can be shortened or where the load can be reduced by changing open points, adding switches or building new supply feeders.

Enersource is implementing a computerized load flow program that will provide an analysis of the system in a quicker, more accurate and methodical fashion. The load flow program will allow Enersource to more efficiently analyze weaknesses in the system. Enersource presently does much of this analysis manually using data from prior periods and applying its knowledge of the distribution system. As a result, this analysis is time consuming, onerous and prone to human error. Automating this analysis is expected to identify robust solutions that can be tested against a variety of operating scenarios in an accurate and timely manner.

In addition to the reduction of the losses on distribution lines, Enersource strives to reduce system losses caused by distribution transformers. Through a competitive process, Enersource purchases single-phase and three-phase pad-mounted transformers that meet or exceed the minimum efficiency requirement of the CSA Standard C802.1.

Enersource also works with commercial and industrial customers requiring dedicated distribution transformers to ensure that the units supplying the customers are properly sized to the customer loads.

Distribution System Losses

Total distribution system losses are calculated by taking the total energy purchased over a year and dividing it by the total energy that was billed to customers during the same year. Table 1 provides total system losses as a percentage of total annual purchases over the past five years. It is important to note that losses have not been greater than 5% and that Enersource is not an embedded distributor and contains no distributors embedded in its area.

Table 1: Total Historical Distribution System Loss Factors

Total Losses as a % of Purchases						
	2007	**2008**	**2009**	**2010**	**2011**	**Five Year Average**
Total Electricity Purchases[1] (MWh)	8,249,691,981	8,096,551,762	7,742,344,266	7,949,145,632	7,880,490,220	7,983,644,772
Total Electricity Sales[2] (MWh)	7,935,279,547	7,821,062,568	7,498,987,529	7,708,674,748	7,626,204,363	7,718,041,751
Total Losses (MWH)	314,412,434	275,489,194	243,356,737	240,470,884	254,285,857	265,603,021
Loss %[3]	3.96%	3.52%	3.25%	3.12%	3.33%	3.44%

[1] Line A(1) of Appendix 2-P.
[2] Line D of Appendix 2-P.
[3] Line A(1) divided by Line D of Appendix 2-P.

Determination of Loss Adjustment Factors

As shown at Exhibit 8 Tab 7 Schedule 1 Appendix 2-P, Enersource's total loss factor ("TLF") for the past five years has averaged 1.0379.

This TLF is higher than Enersource's current, and proposed, TLF of 1.0360.

Enersource proposes excluding 2007 from the analysis as that year experienced an unusually high TLF. The more recent four years of historical actuals more accurately align with the current and proposed TLF.

As a result of this analysis, Enersource is proposing to continue with the current OEB-approved TLF of 1.0360 for Secondary Metered Customers <5000 kW for the 2013 Test Year. The TLF for Primary Metered Customers <5000 kW is calculated by multiplying the TLF for Secondary Metered Customers <5000 kW by 0.99.

Enersource proposes to continue to use a 1.0045 TLF for Primary Metered Customers >5000 kW and 1.0145 for Secondary Metered Customers >5000 kW.

Appendix 2-P
Loss Factors

		Historical Years					5-Year Average
		2007	2008	2009	2010	2011	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	8,249,691,981	8,096,551,762	7,742,344,266	7,949,145,632	7,880,490,220	7,983,644,772
A(2)	"Wholesale" kWh delivered to distributor (lower value)	8,212,734,675	8,060,280,500	7,707,659,797	7,913,534,726	7,845,186,879	7,947,879,315
B	Portion of "Wholesale" kWh delivered to distributor for its Large	1,027,043,917	1,066,438,921	1,019,358,132	1,064,815,720	1,062,207,206	1,047,972,779
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	7,185,690,758	6,993,841,579	6,688,301,665	6,848,719,006	6,782,979,673	6,899,906,536
D	"Retail" kWh delivered by distributor	7,935,279,547	7,821,062,568	7,498,987,529	7,708,674,748	7,626,204,363	7,718,041,751
E	Portion of "Retail" kWh delivered by distributor to its Large Use	1,016,875,166	1,055,880,120	1,009,265,477	1,054,272,990	1,051,690,303	1,037,596,811
F	Net "Retail" kWh delivered by distributor = **D - E**	6,918,404,381	6,765,182,448	6,489,722,052	6,654,401,758	6,574,514,060	6,680,444,940
G	Loss Factor in Distributor's system = **C / F**	1.0386	1.0338	1.0306	1.0292	1.0317	1.0329
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0433	1.0385	1.0352	1.0338	1.0364	1.0375

Rate Schedules

Tariff of Rates and Charges - Terms and Conditions of Service

As provided for in the 2006 Electricity Distribution Rate Handbook[1], Enersource will continue its current practice to establish the billing demands at the greater of 100% of the kW, or 90% of the kVa amounts.

Also, Enersource will continue to bill certain customers pursuant to individually negotiated contract terms which supersede rates schedules and tariffs approved by the Board.

Tariff of Rates and Charges – Monthly Rates and Charges

Enersource is seeking Board approval for rates effective January 1, 2013, which is a change from Enersource's previously effective date for distribution rate changes of May 1. As a result, the Shared Tax Savings Rate Rider which is currently effective from May 1, 2012 to April 30, 2013 is proposed to be eliminated as at December 31, 2012. This change has been reflected in the Proposed Tariff of Rates and Charges at Exhibit 8 Tab 1 Schedule 1 Appendix 1.

Enersource is proposing an adjustment to its rate classes to include a separate Unmetered Scattered Loads ("USL") rate class and to merge the Small Commercial less than 50 kW rate class with the General Service less than 50 kW rate class. These customers are not sufficiently different in service setup, billing, collections, and meter reading profiles to require separate rate classes. See Exhibit 7 Tab 1 Schedule 1 and Exhibit 8 Tab 1 Schedule 1 for details.

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[1] The Board's 2006 Electricity Distribution Rate Handbook, section 10.8.

Enersource is proposing to create a Low Voltage ("LV") rate to recover LV charges to Enersource from customers for the 2013 Test Year. The revenue generated from this new LV rate will be recorded to account 1550 to offset the Hydro One LV charges that are currently recorded in the same account. See Exhibit 8 Tab 6 Schedule 1 for details.

Revenue Reconciliation

See Exhibit 8 Tab 8 Schedule 1 Appendix 2-U for the revenue reconciliation between revenues at the proposed rates and the service revenue requirement plus transformer allowance credit.

Appendix 2-U
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	175,874	177,856	176,865	1,423,857,475		$ 14.68	$ 0.0144		$ 51,638,053	$ 50,852,200	$ 785,853	$ 51,638,053	$ -
GS < 50 kW	Customers	17,580	17,825	17,703	612,188,101		$ 44.69	$ 0.0133		$ 17,624,530	$ 17,356,311	$ 268,219	$ 17,624,530	$ -
Unmetered Scattered Load	Connections	2,943	2,940	2,942	10,383,027		$ 9.16	$ 0.0174		$ 504,566	$ 496,888	$ 7,679	$ 504,566	$ -
GS 50 to 499 kW	Customers	3,948	3,951	3,950		6,142,022	$ 78.50		$ 4.7545	$ 32,922,932	$ 32,421,895	$ 501,037	$ 32,922,932	$ -
GS 500 to 4,999 kW	Customers	464	464	464		5,154,338	$ 1,639.67		$ 2.2972	$ 20,970,276	$ 20,651,140	$ 319,136	$ 20,970,276	$ -
Large Use	Customers	9	9	9		1,737,267	$ 12,712.31		$ 2.7346	$ 6,123,650	$ 6,030,457	$ 93,193	$ 6,123,650	$ -
Streetlighting	Connections	49,736	50,235	49,986		49,889	$ 1.51		$ 11.9857	$ 1,501,158	$ 1,478,312	$ 22,845	$ 1,501,158	$ -
										$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total		250,554	253,280	251,919	2,046,428,603	13,083,516	14,500.53	0.05	21.77	$ 131,285,165	$ 129,287,204	$ 1,997,962	$ 131,285,166	$ 1

Bill Impacts

Bill impacts for typical customers in all classes have been calculated using the proposed rates. Details are provided at Exhibit 8 Tab 9 Schedule 1 Appendix 2-V. It is important to note that the impact of the change in distribution rates includes the low voltage rate adder.

2013 Test Year

A typical RPP residential customer consuming 800 kWh per month would see the delivery portion of their bill increase by 16.3% or $5.10, with an overall bill increase of 4.9% or $5.20. A non-RPP residential customer using 800 kWh per month would see the delivery portion of their bill increase by 18.6% or $5.50, with an overall bill increase of 5.4% or $5.59.

A typical RPP GS<50 kW customer consuming 2,000 kWh per month would see the delivery portion of their bill increase by 6.3% or $5.31, with an overall bill increase of 1.9% or $5.40. A non-RPP GS<50 kW customer using 2,000 kWh per month would see the delivery portion of their bill increase by 7.8% or $6.31, with an overall bill increase of 2.3% or $6.42.

2014 ICR Year

A typical RPP residential customer consuming 800 kWh per month would see the delivery portion of their bill increase by 0.1% or $0.04, with an overall bill increase of 0.03% or $0.03. A non-RPP residential customer using 800 kWh per month would see the delivery portion of their bill decrease by 1.0% or $0.36, with an overall bill decrease of 0.3% or $0.37.

A typical RPP GS<50 kW customer consuming 2,000 kWh per month would see the delivery portion of their bill increase by 5.5% or $4.96, with an overall bill

increase of 1.8% or $5.05. A non-RPP GS<50 kW customer using 2,000 kWh per month would see the delivery portion of their bill increase by 4.6% or $3.96, with an overall bill increase of 1.4% or $4.03.

Tables 1 and 2 summarize the bill impacts pursuant to Exhibit 8 Tab 9 Schedule 1 Appendix 2-V.

Table 1: 2013 Bill Impacts Summary

kWh	kW	Current Distr. $	Proposed Distr. $	Impact $	Impact %	Current Delivery $	Proposed Delivery $	Impact $	Impact %	Current Total	Proposed Total	Impact $	Impact %
Residential - RPP													
100	-	13.68	19.06	5.38	39.3	14.98	20.36	5.38	35.9	24.38	29.85	5.47	22.4
250	-	15.24	20.56	5.32	34.9	18.49	23.81	5.32	28.8	41.20	46.61	5.41	13.1
500	-	17.84	23.06	5.22	29.3	24.34	29.56	5.22	21.4	69.29	74.60	5.31	7.7
800	-	20.96	26.06	5.10	24.3	31.36	36.46	5.10	16.3	105.80	111.00	5.20	4.9
1000	-	23.04	28.06	5.02	21.8	36.04	41.06	5.02	13.9	130.79	135.90	5.11	3.9
1500	-	28.24	33.06	4.82	17.1	47.74	52.56	4.82	10.1	193.29	198.20	4.90	2.5
2000	-	33.44	38.06	4.62	13.8	59.44	64.06	4.62	7.8	255.80	260.49	4.70	1.8
Residential - Non RPP													
100	-	13.46	18.89	5.43	40.3	14.76	20.19	5.43	36.8	24.15	29.68	5.52	22.9
250	-	14.69	20.14	5.45	37.1	17.94	23.39	5.45	30.4	40.64	46.18	5.54	13.6
500	-	16.74	22.21	5.47	32.7	23.24	28.71	5.47	23.5	68.17	73.73	5.56	8.2
800	-	19.20	24.70	5.50	28.6	29.60	35.10	5.50	18.6	104.02	109.61	5.59	5.4
1000	-	20.84	26.36	5.52	26.5	33.84	39.36	5.52	16.3	128.55	134.17	5.61	4.4
1500	-	24.94	30.51	5.57	22.3	44.44	50.01	5.57	12.5	189.94	195.60	5.66	3.0
2000	-	29.04	34.66	5.62	19.4	55.04	60.66	5.62	10.2	251.32	257.04	5.72	2.3
General Service < 50 kW RPP													
1000	-	50.80	57.21	6.41	12.6	62.80	69.21	6.41	10.2	156.18	162.69	6.52	4.2
2000	-	60.90	66.21	5.31	8.7	84.90	90.21	5.31	6.3	279.85	285.25	5.40	1.9
5000	-	91.20	93.21	2.01	2.2	151.20	153.21	2.01	1.3	650.90	652.95	2.04	0.3
10000	-	141.70	138.21	-3.49	- 2.5	261.70	258.21	-3.49	- 1.3	1,269.32	1,265.77	-3.55	- 0.3
15000	-	192.20	183.21	-8.99	- 4.7	372.20	363.21	-8.99	- 2.4	1,887.73	1,878.58	-9.14	- 0.5
General Service < 50 kW Non RPP													
1000	-	48.60	55.51	6.91	14.2	60.60	67.51	6.91	11.4	153.94	160.97	7.03	4.6
2000	-	56.50	62.81	6.31	11.2	80.50	86.81	6.31	7.8	275.38	281.80	6.42	2.3
5000	-	80.20	84.71	4.51	5.6	140.20	144.71	4.51	3.2	639.72	644.30	4.59	0.7
10000	-	119.70	121.21	1.51	1.3	239.70	241.21	1.51	0.6	1,246.94	1,248.48	1.54	0.1
15000	-	159.20	157.71	-1.49	- 0.9	339.20	337.71	-1.49	- 0.4	1,854.17	1,852.65	-1.52	- 0.1

Table 1: 2013 Bill Impacts Summary continued

kWh	kW	Current Distr. $	Proposed Distr. $	Impact $	Impact %	Current Delivery $	Proposed Delivery $	Impact $	Impact %	Current Total	Proposed Total	Impact $	Impact %
Unmetered Scattered Load RPP													
300	-	15.79	12.19	-3.60	- 22.8	19.39	15.79	-3.60	- 18.6	46.57	42.89	-3.68	- 7.9
General Service 50 < 499 kW Non RPP													
25000	60	251.36	267.25	15.89	6.3	530.01	545.90	15.89	3.0	3,400.32	3,418.28	17.96	0.5
40000	100	371.84	392.19	20.35	5.5	836.27	856.62	20.35	2.4	5,433.17	5,456.16	23.00	0.4
100000	230	763.41	798.26	34.85	4.6	1,831.60	1,866.45	34.85	1.9	13,305.10	13,344.47	39.37	0.3
200000	500	1,576.68	1,641.63	64.95	4.1	3,898.83	3,963.78	64.95	1.7	26,886.13	26,959.53	73.39	0.3
400000	1000	3,082.73	3,203.43	120.70	3.9	7,727.03	7,847.73	120.70	1.6	53,702.35	53,838.74	136.39	0.3
General Service 500 < 4999 kW Non RPP													
200000	1250	2,289.79	2,218.77	-71.02	- 3.1	7,934.29	7,863.27	-71.02	- 0.9	31,446.21	31,365.95	-80.25	- 0.3
400000	2250	2,890.39	2,682.37	-208.02	- 7.2	13,050.49	12,842.47	-208.02	- 1.6	59,717.96	59,482.89	-235.07	- 0.4
Large Use Non RPP													
3000000	5000	18,485.17	14,199.84	-4,285.33	- 23.2	42,587.17	38,301.84	-4,285.33	- 10.1	378,960.15	374,117.73	-4,842.42	- 1.3
Street Lighting													
33	0.1	2.21	2.43	0.22	10.1	2.54	2.76	0.22	8.8	6.39	6.64	0.25	3.9

Table 2: 2014 Bill Impacts Summary

kWh	kW	Current Distr. $	Proposed Distr. $	Impact $	Impact %	Current Delivery $	Proposed Delivery $	Impact $	Impact %	Current Total	Proposed Total	Impact $	Impact %
Residential - RPP													
100	-	19.06	16.44	-2.62	- 13.7	20.36	17.74	-2.62	- 12.9	29.85	27.18	-2.66	- 8.9
250	-	20.56	18.51	-2.05	- 10.0	23.81	21.76	-2.05	- 8.6	46.61	44.52	-2.08	- 4.5
500	-	23.06	21.96	-1.10	- 4.8	29.56	28.46	-1.10	- 3.7	74.60	73.48	-1.12	- 1.5
800	-	26.06	26.10	0.04	0.2	36.46	36.50	0.04	0.1	111.00	111.03	0.03	0.0
1000	-	28.06	28.86	0.80	2.9	41.06	41.86	0.80	1.9	135.90	136.71	0.81	0.6
1500	-	33.06	35.76	2.70	8.2	52.56	55.26	2.70	5.1	198.20	200.94	2.75	1.4
2000	-	38.06	42.66	4.60	12.1	64.06	68.66	4.60	7.2	260.49	265.17	4.68	1.8
Residential - Non RPP													
100	-	18.89	16.22	-2.67	- 14.1	20.19	17.52	-2.67	- 13.2	29.68	26.96	-2.72	- 9.2
250	-	20.14	17.96	-2.18	- 10.8	23.39	21.21	-2.18	- 9.3	46.18	43.97	-2.21	- 4.8
500	-	22.21	20.86	-1.35	- 6.1	28.71	27.36	-1.35	- 4.7	73.73	72.36	-1.37	- 1.9
800	-	24.70	24.34	-0.36	- 1.5	35.10	34.74	-0.36	- 1.0	109.61	109.24	-0.37	- 0.3
1000	-	26.36	26.66	0.30	1.1	39.36	39.66	0.30	0.8	134.17	134.47	0.31	0.2
1500	-	30.51	32.46	1.95	6.4	50.01	51.96	1.95	3.9	195.60	197.58	1.98	1.0
2000	-	34.66	38.26	3.60	10.4	60.66	64.26	3.60	5.9	257.04	260.70	3.66	1.4
General Service < 50 kW RPP													
1000	-	57.21	58.47	1.26	2.2	69.21	70.47	1.26	1.8	162.69	163.98	1.28	0.8
2000	-	66.21	71.17	4.96	7.5	90.21	95.17	4.96	5.5	285.25	290.30	5.05	1.8
5000	-	93.21	109.27	16.06	17.2	153.21	169.27	16.06	10.5	652.95	669.28	16.33	2.5
10000	-	138.21	172.77	34.56	25.0	258.21	292.77	34.56	13.4	1,265.77	1,300.91	35.15	2.8
15000	-	183.21	236.27	53.06	29.0	363.21	416.27	53.06	14.6	1,878.58	1,932.55	53.96	2.9
General Service < 50 kW Non RPP													
1000	-	55.51	56.27	0.76	1.4	67.51	68.27	0.76	1.1	160.97	161.74	0.77	0.5
2000	-	62.81	66.77	3.96	6.3	86.81	90.77	3.96	4.6	281.80	285.83	4.03	1.4
5000	-	84.71	98.27	13.56	16.0	144.71	158.27	13.56	9.4	644.30	658.09	13.79	2.1
10000	-	121.21	150.77	29.56	24.4	241.21	270.77	29.56	12.3	1,248.48	1,278.54	30.06	2.4
15000	-	157.71	203.27	45.56	28.9	337.71	383.27	45.56	13.5	1,852.65	1,898.99	46.33	2.5

Table 2: 2014 Bill Impacts Summary continued

kWh	kW	Current Distr. $	Proposed Distr. $	Impact $	Impact %	Current Delivery $	Proposed Delivery $	Impact $	Impact %	Current Total	Proposed Total	Impact $	Impact %
Unmetered Scattered Load RPP													
300	-	12.19	14.45	2.26	18.5	15.79	18.05	2.26	14.3	42.89	45.20	2.31	5.4
General Service 50 < 499 kW Non RPP													
25000	60	267.25	311.16	43.91	16.4	545.90	589.81	43.91	8.0	3,418.28	3,467.90	49.62	1.5
40000	100	392.19	465.00	72.81	18.6	856.62	929.43	72.81	8.5	5,456.16	5,538.44	82.28	1.5
100000	230	798.26	964.99	166.74	20.9	1,866.45	2,033.18	166.74	8.9	13,344.47	13,532.88	188.41	1.4
200000	500	1,641.63	2,003.44	361.81	22.0	3,963.78	4,325.59	361.81	9.1	26,959.53	27,368.37	408.85	1.5
400000	1000	3,203.43	3,926.49	723.06	22.6	7,847.73	8,570.79	723.06	9.2	53,838.74	54,655.79	817.06	1.5
General Service 500 < 4999 kW Non RPP													
200000	1250	2,218.77	2,953.00	734.22	33.1	7,863.27	8,597.50	734.22	9.3	31,365.95	32,195.63	829.67	2.6
400000	2250	2,682.37	3,972.10	1,289.73	48.1	12,842.47	14,132.20	1,289.73	10.0	59,482.89	60,940.28	1,457.39	2.5
Large Use Non RPP													
3000000	5000	14,199.84	17,749.32	3,549.48	25.0	38,301.84	41,851.32	3,549.48	9.3	374,117.73	378,128.65	4,010.92	1.1
Street Lighting													
33	0.1	2.43	2.69	0.26	10.5	2.76	3.02	0.26	9.2	6.64	6.93	0.29	4.3

Appendix 2-V
2013 Bill Impacts

Customer Class: **Residential - RPP**

Consumption **800** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 11.87	1	$ 11.87	$ 14.70	1	$ 14.70	$ 2.83	23.84%
Smart Meter Rate Adder	Monthly	$ 0.77	1	$ 0.77		1	$ -	-$ 0.77	-100.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0119	800	$ 9.52	$ 0.0144	800	$ 11.52	$ 2.00	21.01%
Low Voltage Rate Adder			800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider	Monthly		800	$ -	$ 0.13	1	$ 0.13	$ 0.13	
LRAM & SSM Rate Rider	per kWh	$ 0.0003	800	$ 0.24	$ 0.0003	800	$ 0.24	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0014	800	-$ 1.12	-$ 0.0049	800	-$ 3.92	-$ 2.80	250.00%
Stranded Meters Disposition	Monthly			$ -	$ 3.23	1	$ 3.23	$ 3.23	
Tax Change	per kWh	-$ 0.0004	800	-$ 0.32	$ -	800	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 20.96**			**$ 26.06**	**$ 5.10**	**24.33%**
RTSR - Network	per kWh	$ 0.0073	800	$ 5.84	$ 0.0073	800	$ 5.84	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0057	800	$ 4.56	$ 0.0057	800	$ 4.56	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 31.36**			**$ 36.46**	**$ 5.10**	**16.26%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	829	$ 4.31	$ 0.0052	829	$ 4.31	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	829	$ 0.91	$ 0.0011	829	$ 0.91	$ -	0.00%
Special Purpose Charge			800	$ -		800	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Energy	per kWh	$ 0.0710	600	$ 42.60	$ 0.0710	600	$ 42.60	$ -	0.00%
Energy	per kWh	$ 0.0830	229	$ 19.01	$ 0.0830	229	$ 19.01	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 104.04**			**$ 109.14**	**$ 5.10**	**4.90%**
HST		13%		$ 13.53	13%		$ 14.19	$ 0.66	4.90%
Total Bill (including Sub-total B)				**$ 117.56**			**$ 123.33**	**$ 5.77**	**4.91%**
Ontario Clean Energy Benefit [1]				**-$ 11.76**			**-$ 12.33**	**-$ 0.57**	**4.85%**
Total Bill (including OCEB)				**$ 105.80**			**$ 111.00**	**$ 5.20**	**4.91%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **Residential - Non-RPP**

Consumption **800** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 11.87	1	$ 11.87	$ 14.70	1	$ 14.70	$ 2.83	23.84%
Smart Meter Rate Adder	Monthly	$ 0.77	1	$ 0.77		1	$ -	-$ 0.77	-100.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0119	800	$ 9.52	$ 0.0144	800	$ 11.52	$ 2.00	21.01%
Low Voltage Rate Adder			800	$ -	$ 0.0002	800	$ 0.16	$ 0.16	
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider	Monthly		800	$ -	$ 0.13	1	$ 0.13	$ 0.13	
LRAM & SSM Rate Rider	per kWh	$ 0.0003	800	$ 0.24	$ 0.0003	800	$ 0.24	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0036	800	-$ 2.88	-$ 0.0066	800	-$ 5.28	-$ 2.40	83.33%
Stranded Meters Disposition	Monthly			$ -	$ 3.23	1	$ 3.23	$ 3.23	
Tax Change	per kWh	-$ 0.0004	800	-$ 0.32	$ -	800	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 19.20**			**$ 24.70**	**$ 5.50**	**28.65%**
RTSR - Network	per kWh	$ 0.0073	800	$ 5.84	$ 0.0073	800	$ 5.84	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0057	800	$ 4.56	$ 0.0057	800	$ 4.56	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 29.60**			**$ 35.10**	**$ 5.50**	**18.58%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	829	$ 4.31	$ 0.0052	829	$ 4.31	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	829	$ 0.91	$ 0.0011	829	$ 0.91	$ -	0.00%
Special Purpose Charge			800	$ -		800	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Energy	per kWh	$ 0.0710	600	$ 42.60	$ 0.0710	600	$ 42.60	$ -	0.00%
Energy	per kWh	$ 0.0830	229	$ 19.01	$ 0.0830	229	$ 19.01	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 102.28**			**$ 107.78**	**$ 5.50**	**5.38%**
HST		13%		$ 13.30	13%		$ 14.01	$ 0.71	5.38%
Total Bill (including Sub-total B)				**$ 115.58**			**$ 121.79**	**$ 6.21**	**5.37%**
Ontario Clean Energy Benefit [1]				**-$ 11.56**			**-$ 12.18**	**-$ 0.62**	**5.36%**
Total Bill (including OCEB)				**$ 104.02**			**$ 109.61**	**$ 5.59**	**5.37%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **GS < 50 - RPP**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 39.93	1	$ 39.93	$ 44.68	1	$ 44.68	$ 4.75	11.90%
Smart Meter Rate Adder	Monthly	$ 0.77	1	$ 0.77		1	$ -	-$ 0.77	-100.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0116	2000	$ 23.20	$ 0.0133	2000	$ 26.60	$ 3.40	14.66%
Low Voltage Rate Adder			2000	$ -	$ 0.0002	2000	$ 0.40	$ 0.40	
Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
Smart Meter Disposition Rider	Monthly		2000	$ -	$ 0.13	1	$ 0.13	$ 0.13	
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0014	2000	-$ 2.80	-$ 0.0047	2000	-$ 9.40	-$ 6.60	235.71%
Stranded Meters Disposition	Monthly			$ -	$ 3.40	1	$ 3.40	$ 3.40	
Tax Change	per kWh	-$ 0.0003	2000	-$ 0.60	$ -	2000	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 60.90**			**$ 66.21**	**$ 5.31**	**8.72%**
RTSR - Network	per kWh	$ 0.0068	2000	$ 13.60	$ 0.0068	2000	$ 13.60	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	2000	$ 10.40	$ 0.0052	2000	$ 10.40	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 84.90**			**$ 90.21**	**$ 5.31**	**6.25%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2072	$ 10.77	$ 0.0052	2072	$ 10.77	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2072	$ 2.28	$ 0.0011	2072	$ 2.28	$ -	0.00%
Special Purpose Charge			2000	$ -		2000	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	1322	$ 109.73	$ 0.0830	1322	$ 109.73	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 275.18**			**$ 280.49**	**$ 5.31**	**1.93%**
HST		13%		$ 35.77	13%		$ 36.46	$ 0.69	1.93%
Total Bill (including Sub-total B)				**$ 310.95**			**$ 316.95**	**$ 6.00**	**1.93%**
Ontario Clean Energy Benefit [1]				**-$ 31.10**			**-$ 31.70**	**-$ 0.60**	**1.93%**
Total Bill (including OCEB)				**$ 279.85**			**$ 285.25**	**$ 5.40**	**1.93%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **GS < 50 - Non-RPP**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 39.93	1	$ 39.93	$ 44.68	1	$ 44.68	$ 4.75	11.90%
Smart Meter Rate Adder	Monthly	$ 0.77	1	$ 0.77		1	$ -	-$ 0.77	-100.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0116	2000	$ 23.20	$ 0.0133	2000	$ 26.60	$ 3.40	14.66%
Low Voltage Rate Adder			2000	$ -	$ 0.0002	2000	$ 0.40	$ 0.40	
Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
Smart Meter Disposition Rider	Monthly		2000	$ -	$ 0.13	1	$ 0.13	$ 0.13	
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0036	2000	-$ 7.20	-$ 0.0064	2000	-$ 12.80	-$ 5.60	77.78%
Stranded Meters Disposition	Monthly			$ -	$ 3.40	1	$ 3.40	$ 3.40	
Tax Change	per kWh	-$ 0.0003	2000	-$ 0.60	$ -	2000	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 56.50**			**$ 62.81**	**$ 6.31**	**11.17%**
RTSR - Network	per kWh	$ 0.0068	2000	$ 13.60	$ 0.0068	2000	$ 13.60	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	2000	$ 10.40	$ 0.0052	2000	$ 10.40	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 80.50**			**$ 86.81**	**$ 6.31**	**7.84%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2072	$ 10.77	$ 0.0052	2072	$ 10.77	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2072	$ 2.28	$ 0.0011	2072	$ 2.28	$ -	0.00%
Special Purpose Charge			2000	$ -		2000	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	1322	$ 109.73	$ 0.0830	1322	$ 109.73	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 270.78**			**$ 277.09**	**$ 6.31**	**2.33%**
HST		13%		$ 35.20	13%		$ 36.02	$ 0.82	2.33%
Total Bill (including Sub-total B)				**$ 305.98**			**$ 313.11**	**$ 7.13**	**2.33%**
Ontario Clean Energy Benefit [1]				**-$ 30.60**			**-$ 31.31**	**-$ 0.71**	**2.32%**
Total Bill (including OCEB)				**$ 275.38**			**$ 281.80**	**$ 6.42**	**2.33%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption **300** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 10.69	1	$ 10.69	$ 9.16	1	$ 9.16	-$ 1.53	-14.34%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0195	300	$ 5.85	$ 0.0174	300	$ 5.22	-$ 0.63	-10.77%
Low Voltage Rate Adder			300	$ -	$ 0.0002	300	$ 0.06	$ 0.06	
Volumetric Rate Adder(s)			300	$ -		300	$ -	$ -	
Volumetric Rate Rider(s)			300	$ -		300	$ -	$ -	
Smart Meter Disposition Rider	Monthly		300	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	300	$ -	$ -	300	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0018	300	-$ 0.54	-$ 0.0075	300	-$ 2.25	-$ 1.71	316.67%
				$ -			$ -	$ -	
Tax Change	per kWh	-$ 0.0007	300	-$ 0.21	$ -	300	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 15.79**			**$ 12.19**	**-$ 3.60**	**-22.82%**
RTSR - Network	per kWh	$ 0.0068	300	$ 2.04	$ 0.0068	300	$ 2.04	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	300	$ 1.56	$ 0.0052	300	$ 1.56	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 19.39**			**$ 15.79**	**-$ 3.60**	**-18.58%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	311	$ 1.62	$ 0.0052	311	$ 1.62	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	311	$ 0.34	$ 0.0011	311	$ 0.34	$ -	0.00%
Special Purpose Charge			300	$ -		300	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	300	$ 2.10	$ 0.0070	300	$ 2.10	$ -	0.00%
Energy	per kWh	$ 0.0710	311	$ 22.08	$ 0.0710	311	$ 22.08	$ -	0.00%
Energy	per kWh	$ 0.0830	0	$ -	$ 0.0830	0	$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 45.78**			**$ 42.18**	**-$ 3.60**	**-7.87%**
HST		13%		$ 5.95	13%		$ 5.48	-$ 0.47	-7.87%
Total Bill (including Sub-total B)				**$ 51.74**			**$ 47.66**	**-$ 4.08**	**-7.89%**
Ontario Clean Energy Benefit [1]				**-$ 5.17**			**-$ 4.77**	**$ 0.40**	**-7.74%**
Total Bill (including OCEB)				**$ 46.57**			**$ 42.89**	**-$ 3.68**	**-7.90%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **GS 50 - 499 kW**

	Consumption	**230**	**kW**		**100000**	**kWh**			
		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 69.86	1	$ 69.86	$ 78.48	1	$ 78.48	$ 8.62	12.34%
Smart Meter Rate Adder	Monthly	$ 0.77	1	$ 0.77		1	$ -	-$ 0.77	-100.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.2044	230	$ 967.01	$ 4.7533	230	$ 1,093.26	$ 126.25	13.06%
Low Voltage Rate Adder			230	$ -	$ 0.0805	230	$ 18.52	$ 18.52	
Volumetric Rate Adder(s)			230	$ -		230	$ -	$ -	
Volumetric Rate Rider(s)			230	$ -		230	$ -	$ -	
Smart Meter Disposition Rider	Monthly			$ -	$ 0.13	1	$ 0.13	$ 0.13	
LRAM & SSM Rate Rider	per kW	$ 0.0281	230	$ 6.46	$ 0.0281	230	$ 6.46	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.1578	230	-$ 266.29	-$ 1.7383	230	-$ 399.81	-$ 133.52	50.14%
Stranded Meters Disposition	Monthly			$ -	$ 1.22	1	$ 1.22	$ 1.22	
Tax Change	per kW	-$ 0.0626	230	-$ 14.40	$ -	230	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 763.41**			**$ 798.26**	**$ 34.85**	**4.56%**
RTSR - Network	per kW	$ 2.6160	230	$ 601.68	$ 2.6160	230	$ 601.68	$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 2.0283	230	$ 466.51	$ 2.0283	230	$ 466.51	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 1,831.60**			**$ 1,866.45**	**$ 34.85**	**1.90%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	103601	$ 538.73	$ 0.0052	103601	$ 538.73	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	103601	$ 113.96	$ 0.0011	103601	$ 113.96	$ -	0.00%
Special Purpose Charge			103601	$ -		230	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	100000	$ 700.00	$ 0.0070	100000	$ 700.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	102851	$ 8,536.63	$ 0.0830	102851	$ 8,536.63	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 11,774.42**			**$ 11,809.27**	**$ 34.85**	**0.30%**
HST		13%		$ 1,530.67	13%		$ 1,535.20	$ 4.53	0.30%
Total Bill (including Sub-total B)				**$ 13,305.10**			**$ 13,344.47**	**$ 39.37**	**0.30%**
Ontario Clean Energy Benefit [1]				**$ -**			**$ -**	**$ -**	
Total Bill (including OCEB)				**$ 13,305.10**			**$ 13,344.47**	**$ 39.37**	**0.30%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **GS 500 - 4999 kW**

Consumption 2250 kW 400000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 1,538.27	1	$ 1,538.27	$ 1,639.27	1	$ 1,639.27	$ 101.00	6.57%
Smart Meter Rate Adder	Monthly	$ 0.77	1	$ 0.77		1	$ -	-$ 0.77	-100.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.0981	2250	$ 4,720.73	$ 2.2966	2250	$ 5,167.35	$ 446.63	9.46%
Low Voltage Rate Adder			2250	$ -	$ 0.0788	2250	$ 177.30	$ 177.30	
Volumetric Rate Adder(s)			2250	$ -		2250	$ -	$ -	
Volumetric Rate Rider(s)			2250	$ -		2250	$ -	$ -	
Smart Meter Disposition Rider			2250	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0111	2250	$ 24.98	$ 0.0111	2250	$ 24.98	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.4592	2250	-$ 3,283.20	-$ 1.9229	2250	-$ 4,326.53	########	31.78%
				$ -			$ -	$ -	
Tax Change	per kW	-$ 0.0494	2250	-$ 111.15	$ -	2250	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 2,890.39**			**$ 2,682.37**	**-$ 208.02**	**-7.20%**
RTSR - Network	per kW	$ 2.5309	2250	$ 5,694.53	$ 2.5309	2250	$ 5,694.53	$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 1.9847	2250	$ 4,465.58	$ 1.9847	2250	$ 4,465.58	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 13,050.49**			**$ 12,842.47**	**-$ 208.02**	**-1.59%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	414401	$ 2,154.89	$ 0.0052	414401	$ 2,154.89	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	414401	$ 455.84	$ 0.0011	414401	$ 455.84	$ -	0.00%
Special Purpose Charge			414401	$ -		2250	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	400000	$ 2,800.00	$ 0.0070	400000	$ 2,800.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	413651	$ 34,333.03	$ 0.0830	413651	$ 34,333.03	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 52,847.75**			**$ 52,639.73**	**-$ 208.02**	**-0.39%**
HST		13%		$ 6,870.21	13%		$ 6,843.16	-$ 27.04	-0.39%
Total Bill (including Sub-total B)				**$ 59,717.96**			**$ 59,482.89**	**-$ 235.07**	**-0.39%**
Ontario Clean Energy Benefit [1]				**$ -**			**$ -**	**$ -**	
Total Bill (including OCEB)				**$ 59,717.96**			**$ 59,482.89**	**-$ 235.07**	**-0.39%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **Large Use**

Consumption 5000 kW 3000000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 13,856.90	1	$ 13,856.90	$ 12,628.34	1	$ 12,628.34	-$ 1,228.56	-8.87%
Smart Meter Rate Adder	Monthly	$ 0.77	1	$ 0.77		1	$ -	-$ 0.77	-100.00%
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.9225	5000	$ 14,612.50	$ 2.7165	5000	$ 13,582.50	-$ 1,030.00	-7.05%
Low Voltage Rate Adder			5000	$ -	$ 0.0841	5000	$ 420.50	$ 420.50	
Volumetric Rate Adder(s)			5000	$ -		5000	$ -	$ -	
Volumetric Rate Rider(s)			5000	$ -		5000	$ -	$ -	
Smart Meter Disposition Rider			5000	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0035	5000	$ 17.50	$ 0.0035	5000	$ 17.50	$ -	0.00%
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.9503	5000	-$ 9,751.50	-$ 2.4898	5000	-$ 12,449.00	-$ 2,697.50	27.66%
				$ -			$ -	$ -	
Tax Change	per kW	-$ 0.0502	5000	-$ 251.00	$ -	5000	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 18,485.17**			**$ 14,199.84**	**-$ 4,285.33**	**-23.18%**
RTSR - Network	per kW	$ 2.7007	5000	$ 13,503.50	$ 2.7007	5000	$ 13,503.50	$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 2.1197	5000	$ 10,598.50	$ 2.1197	5000	$ 10,598.50	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 42,587.17**			**$ 38,301.84**	**-$ 4,285.33**	**-10.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	3043500	$ 15,826.20	$ 0.0052	3043500	$ 15,826.20	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	3043500	$ 3,347.85	$ 0.0011	3043500	$ 3,347.85	$ -	0.00%
Special Purpose Charge			3043500	$ -		5000	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	3000000	$ 21,000.00	$ 0.0070	3000000	$ 21,000.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	3042750	$ 252,548.25	$ 0.0830	3042750	$ 252,548.25	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 335,362.97**			**$ 331,077.64**	**-$ 4,285.33**	**-1.28%**
HST		13%		$ 43,597.19	13%		$ 43,040.09	-$ 557.09	-1.28%
Total Bill (including Sub-total B)				**$ 378,960.15**			**$ 374,117.73**	**-$ 4,842.42**	**-1.28%**
Ontario Clean Energy Benefit [1]				**$ -**			**$ -**	**$ -**	
Total Bill (including OCEB)				**$ 378,960.15**			**$ 374,117.73**	**-$ 4,842.42**	**-1.28%**
Loss Factor (%)		1.4500%			1.4500%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2013 Bill Impacts

Customer Class: **Streetlighting**

	Consumption	**0.1**	**kW**			**33**	**kWh**				
		Current Board-Approved				**Proposed**				**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**		**Rate ($)**	**Volume**	**Charge ($)**		**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 1.34	1	$ 1.34		$ 1.52	1	$ 1.52		$ 0.18	13.29%
Smart Meter Rate Adder			1	$ -			1	$ -		$ -	
Service Charge Rate Adder(s)			1	$ -			1	$ -		$ -	
Service Charge Rate Rider(s)			1	$ -			1	$ -		$ -	
Distribution Volumetric Rate	per kW	$ 10.2587	0.1	$ 1.03		$ 12.0916	0.1	$ 1.21		$ 0.18	17.87%
Low Voltage Rate Adder			0.1	$ -		$ 0.0582	0.1	$ 0.01		$ 0.01	
Volumetric Rate Adder(s)			0.1	$ -			0.1	$ -		$ -	
Volumetric Rate Rider(s)			0.1	$ -			0.1	$ -		$ -	
Smart Meter Disposition Rider			0.1	$ -			1	$ -		$ -	
LRAM & SSM Rate Rider	per kW	$ -	0.1	$ -		$ -	0.1	$ -		$ -	
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.3425	0.1	-$ 0.13		-$ 3.0177	0.1	-$ 0.30		-$ 0.17	124.78%
				$ -				$ -		$ -	
Tax Change	per kW	-$ 0.2253	0.1	-$ 0.02		$ -	0.1	$ -			
				$ -				$ -		$ -	
				$ -				$ -		$ -	
Sub-Total A - Distribution				**$ 2.21**				**$ 2.43**		**$ 0.22**	**10.06%**
RTSR - Network	per kW	$ 1.8116	0.1	$ 0.18		$ 1.8116	0.1	$ 0.18		$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 1.4666	0.1	$ 0.15		$ 1.4666	0.1	$ 0.15		$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 2.54**				**$ 2.76**		**$ 0.22**	**8.76%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	34	$ 0.18		$ 0.0052	34	$ 0.18		$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	34	$ 0.04		$ 0.0011	34	$ 0.04		$ -	0.00%
Special Purpose Charge			34	$ -			0.1	$ -		$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25		$ 0.2500	1	$ 0.25		$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	34	$ 0.24		$ 0.0070	34	$ 0.24		$ -	0.00%
Energy	per kWh	$ 0.0710	34	$ 2.41		$ 0.0710	34	$ 2.41		$ -	0.00%
Energy	per kWh	$ 0.0830	0	$ -		$ 0.0830	0	$ -		$ -	
				$ -				$ -		$ -	
Total Bill (before Taxes)				**$ 5.65**				**$ 5.88**		**$ 0.22**	**3.93%**
HST		13%		$ 0.74		13%		$ 0.76		$ 0.03	3.93%
Total Bill (including Sub-total B)				**$ 6.39**				**$ 6.64**		**$ 0.25**	**3.91%**
Ontario Clean Energy Benefit [1]				**$ -**				**$ -**		**$ -**	
Total Bill (including OCEB)				**$ 6.39**				**$ 6.64**		**$ 0.25**	**3.91%**
Loss Factor (%)		3.600%				3.60%					

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **Residential - RPP**

Consumption 800 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 14.70	1	$ 14.70	$ 15.06	1	$ 15.06	$ 0.36	2.45%
Smart Meter Rate Adder	Monthly	$ -	1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0144	800	$ 11.52	$ 0.0147	800	$ 11.76	$ 0.24	2.08%
Low Voltage Rate Adder		$ 0.0002	800	$ 0.16	$ 0.0002	800	$ 0.16	$ -	0.00%
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ 0.13	1	$ 0.13	$ -	1	$ -	-$ 0.13	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	800	$ 0.24	$ -	800	$ -	-$ 0.24	-100.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0049	800	-$ 3.92	-$ 0.0011	800	-$ 0.88	$ 3.04	-77.55%
Stranded Meters Disposition	Monthly	$ 3.23	1	$ 3.23	$ -	1	$ -	-$ 3.23	-100.00%
Tax Change	per kWh	$ -	800	$ -	$ -	800	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 26.06**			**$ 26.10**	**$ 0.04**	**0.15%**
RTSR - Network	per kWh	$ 0.0073	800	$ 5.84	$ 0.0073	800	$ 5.84	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0057	800	$ 4.56	$ 0.0057	800	$ 4.56	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 36.46**			**$ 36.50**	**$ 0.04**	**0.11%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	829	$ 4.31	$ 0.0052	829	$ 4.31	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	829	$ 0.91	$ 0.0011	829	$ 0.91	$ -	0.00%
Special Purpose Charge			800	$ -		800	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Energy	per kWh	$ 0.0710	600	$ 42.60	$ 0.0710	600	$ 42.60	$ -	0.00%
Energy	per kWh	$ 0.0830	229	$ 19.01	$ 0.0830	229	$ 19.01	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 109.14**			**$ 109.18**	**$ 0.04**	**0.04%**
HST		13%		$ 14.19	13%		$ 14.19	$ 0.01	0.04%
Total Bill (including Sub-total B)				**$ 123.33**			**$ 123.37**	**$ 0.04**	**0.03%**
Ontario Clean Energy Benefit [1]				**-$ 12.33**			**-$ 12.34**	**-$ 0.01**	**0.08%**
Total Bill (including OCEB)				**$ 111.00**			**$ 111.03**	**$ 0.03**	**0.03%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **Residential - Non-RPP**

Consumption **800** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 14.70	1	$ 14.70	$ 15.06	1	$ 15.06	$ 0.36	2.45%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0144	800	$ 11.52	$ 0.0147	800	$ 11.76	$ 0.24	2.08%
Low Voltage Rate Adder		$ 0.0002	800	$ 0.16	$ 0.0002	800	$ 0.16	$ -	0.00%
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ 0.13	1	$ 0.13	$ -	1	$ -	-$ 0.13	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0003	800	$ 0.24	$ -	800	$ -	-$ 0.24	-100.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0066	800	-$ 5.28	-$ 0.0033	800	-$ 2.64	$ 2.64	-50.00%
Stranded Meters Disposition	Monthly	$ 3.23	1	$ 3.23	$ -	1	$ -	-$ 3.23	-100.00%
Tax Change	per kWh	$ -	800	$ -	$ -	800	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 24.70**			**$ 24.34**	**-$ 0.36**	**-1.46%**
RTSR - Network	per kWh	$ 0.0073	800	$ 5.84	$ 0.0073	800	$ 5.84	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0057	800	$ 4.56	$ 0.0057	800	$ 4.56	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 35.10**			**$ 34.74**	**-$ 0.36**	**-1.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	829	$ 4.31	$ 0.0052	829	$ 4.31	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	829	$ 0.91	$ 0.0011	829	$ 0.91	$ -	0.00%
Special Purpose Charge			800	$ -		800	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Energy	per kWh	$ 0.0710	600	$ 42.60	$ 0.0710	600	$ 42.60	$ -	0.00%
Energy	per kWh	$ 0.0830	229	$ 19.01	$ 0.0830	229	$ 19.01	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 107.78**			**$ 107.42**	**-$ 0.36**	**-0.33%**
HST		13%		$ 14.01	13%		$ 13.96	-$ 0.05	-0.33%
Total Bill (including Sub-total B)				**$ 121.79**			**$ 121.38**	**-$ 0.41**	**-0.34%**
Ontario Clean Energy Benefit [1]				**-$ 12.18**			**-$ 12.14**	**$ 0.04**	**-0.33%**
Total Bill (including OCEB)				**$ 109.61**			**$ 109.24**	**-$ 0.37**	**-0.34%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **GS < 50 - RPP**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 44.68	1	$ 44.68	$ 45.77	1	$ 45.77	$ 1.09	2.44%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0133	2000	$ 26.60	$ 0.0136	2000	$ 27.20	$ 0.60	2.26%
Low Voltage Rate Adder		$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	0.00%
Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ 0.13	1	$ 0.13	$ -	1	$ -	-$ 0.13	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	-$ 0.40	-100.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0047	2000	-$ 9.40	-$ 0.0011	2000	-$ 2.20	$ 7.20	-76.60%
Stranded Meters Disposition	Monthly	$ 3.40	1	$ 3.40	$ -	1	$ -	-$ 3.40	-100.00%
Tax Change	per kWh	$ -	2000	$ -	$ -	2000	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 66.21**			**$ 71.17**	**$ 4.96**	**7.49%**
RTSR - Network	per kWh	$ 0.0068	2000	$ 13.60	$ 0.0068	2000	$ 13.60	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	2000	$ 10.40	$ 0.0052	2000	$ 10.40	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 90.21**			**$ 95.17**	**$ 4.96**	**5.50%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2072	$ 10.77	$ 0.0052	2072	$ 10.77	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2072	$ 2.28	$ 0.0011	2072	$ 2.28	$ -	0.00%
Special Purpose Charge			2000	$ -		2000	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	1322	$ 109.73	$ 0.0830	1322	$ 109.73	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 280.49**			**$ 285.45**	**$ 4.96**	**1.77%**
HST		13%		$ 36.46	13%		$ 37.11	$ 0.64	1.77%
Total Bill (including Sub-total B)				**$ 316.95**			**$ 322.56**	**$ 5.61**	**1.77%**
Ontario Clean Energy Benefit [1]				**-$ 31.70**			**-$ 32.26**	**-$ 0.56**	**1.77%**
Total Bill (including OCEB)				**$ 285.25**			**$ 290.30**	**$ 5.05**	**1.77%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **GS < 50 - Non-RPP**

Consumption **2000** **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 44.68	1	$ 44.68	$ 45.77	1	$ 45.77	$ 1.09	2.44%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0133	2000	$ 26.60	$ 0.0136	2000	$ 27.20	$ 0.60	2.26%
Low Voltage Rate Adder		$ 0.0002	2000	$ 0.40	$ 0.0002	2000	$ 0.40	$ -	0.00%
Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ 0.13	1	$ 0.13	$ -	1	$ -	-$ 0.13	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	-$ 0.40	-100.00%
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0064	2000	-$ 12.80	-$ 0.0033	2000	-$ 6.60	$ 6.20	-48.44%
Stranded Meters Disposition	Monthly	$ 3.40	1	$ 3.40	$ -	1	$ -	-$ 3.40	-100.00%
Tax Change	per kWh	$ -	2000	$ -	$ -	2000	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 62.81**			**$ 66.77**	**$ 3.96**	**6.30%**
RTSR - Network	per kWh	$ 0.0068	2000	$ 13.60	$ 0.0068	2000	$ 13.60	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	2000	$ 10.40	$ 0.0052	2000	$ 10.40	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 86.81**			**$ 90.77**	**$ 3.96**	**4.56%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2072	$ 10.77	$ 0.0052	2072	$ 10.77	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2072	$ 2.28	$ 0.0011	2072	$ 2.28	$ -	0.00%
Special Purpose Charge			2000	$ -		2000	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	1322	$ 109.73	$ 0.0830	1322	$ 109.73	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 277.09**			**$ 281.05**	**$ 3.96**	**1.43%**
HST		13%		$ 36.02	13%		$ 36.54	$ 0.51	1.43%
Total Bill (including Sub-total B)				**$ 313.11**			**$ 317.59**	**$ 4.48**	**1.43%**
Ontario Clean Energy Benefit [1]				**-$ 31.31**			**-$ 31.76**	**-$ 0.45**	**1.44%**
Total Bill (including OCEB)				**$ 281.80**			**$ 285.83**	**$ 4.03**	**1.43%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **Unmetered Scattered Load**

Consumption 300 **kWh**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 9.16	1	$ 9.16	$ 9.38	1	$ 9.38	$ 0.22	2.40%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0174	300	$ 5.22	$ 0.0179	300	$ 5.37	$ 0.15	2.87%
Low Voltage Rate Adder		$ 0.0002	300	$ 0.06	$ 0.0002	300	$ 0.06	$ -	0.00%
Volumetric Rate Adder(s)			300	$ -		300	$ -	$ -	
Volumetric Rate Rider(s)			300	$ -		300	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ -	300	$ -	$ -	1	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ -	300	$ -	$ -	300	$ -	$ -	
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0075	300	-$ 2.25	-$ 0.0012	300	-$ 0.36	$ 1.89	-84.00%
				$ -			$ -	$ -	
Tax Change	per kWh	$ -	300	$ -	$ -	300	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 12.19**			**$ 14.45**	**$ 2.26**	**18.54%**
RTSR - Network	per kWh	$ 0.0068	300	$ 2.04	$ 0.0068	300	$ 2.04	$ -	0.00%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	300	$ 1.56	$ 0.0052	300	$ 1.56	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 15.79**			**$ 18.05**	**$ 2.26**	**14.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	311	$ 1.62	$ 0.0052	311	$ 1.62	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	311	$ 0.34	$ 0.0011	311	$ 0.34	$ -	0.00%
Special Purpose Charge			300	$ -		300	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	300	$ 2.10	$ 0.0070	300	$ 2.10	$ -	0.00%
Energy	per kWh	$ 0.0710	311	$ 22.08	$ 0.0710	311	$ 22.08	$ -	0.00%
Energy	per kWh	$ 0.0830	0	$ -	$ 0.0830	0	$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 42.18**			**$ 44.44**	**$ 2.26**	**5.36%**
HST		13%		$ 5.48	13%		$ 5.78	$ 0.29	5.36%
Total Bill (including Sub-total B)				**$ 47.66**			**$ 50.22**	**$ 2.56**	**5.37%**
Ontario Clean Energy Benefit [1]				**-$ 4.77**			**-$ 5.02**	**-$ 0.25**	**5.24%**
Total Bill (including OCEB)				**$ 42.89**			**$ 45.20**	**$ 2.31**	**5.39%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **GS 50 - 499 kW**

	Consumption	**230**	**kW**			**100000**	**kWh**			
		Current Board-Approved				**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**		**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 78.48	1	$ 78.48		$ 80.39	1	$ 80.39	$ 1.91	2.43%
Smart Meter Rate Adder	Monthly		1	$ -			1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -			1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -			1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 4.7533	230	$ 1,093.26		$ 4.8688	230	$ 1,119.82	$ 26.57	2.43%
Low Voltage Rate Adder		$ 0.0805	230	$ 18.52		$ 0.0805	230	$ 18.52	$ -	0.00%
Volumetric Rate Adder(s)			230	$ -			230	$ -	$ -	
Volumetric Rate Rider(s)			230	$ -			230	$ -	$ -	
Smart Meter Disposition Rider	Monthly	$ 0.13	1	$ 0.13		$ -	1	$ -	-$ 0.13	-100.00%
LRAM & SSM Rate Rider	per kW	$ 0.0281	230	$ 6.46		$ -	230	$ -	-$ 6.46	-100.00%
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.7383	230	-$ 399.81		-$ 1.1032	230	-$ 253.74	$ 146.07	-36.54%
Stranded Meters Disposition	Monthly	$ 1.22	1	$ 1.22		$ -	1	$ -	-$ 1.22	-100.00%
Tax Change	per kW	$ -	230	$ -		$ -	230	$ -		
				$ -				$ -	$ -	
				$ -				$ -	$ -	
Sub-Total A - Distribution				**$ 798.26**				**$ 964.99**	**$ 166.74**	**20.89%**
RTSR - Network	per kW	$ 2.6160	230	$ 601.68		$ 2.6160	230	$ 601.68	$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 2.0283	230	$ 466.51		$ 2.0283	230	$ 466.51	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 1,866.45**				**$ 2,033.18**	**$ 166.74**	**8.93%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	103601	$ 538.73		$ 0.0052	103601	$ 538.73	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	103601	$ 113.96		$ 0.0011	103601	$ 113.96	$ -	0.00%
Special Purpose Charge			103601	$ -			230	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25		$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	100000	$ 700.00		$ 0.0070	100000	$ 700.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25		$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	102851	$ 8,536.63		$ 0.0830	102851	$ 8,536.63	$ -	0.00%
				$ -				$ -	$ -	
Total Bill (before Taxes)				**$ 11,809.27**				**$ 11,976.00**	**$ 166.74**	**1.41%**
HST		13%		$ 1,535.20		13%		$ 1,556.88	$ 21.68	1.41%
Total Bill (including Sub-total B)				**$ 13,344.47**				**$ 13,532.88**	**$ 188.41**	**1.41%**
Ontario Clean Energy Benefit [1]				**$ -**				**$ -**	**$ -**	
Total Bill (including OCEB)				**$ 13,344.47**				**$ 13,532.88**	**$ 188.41**	**1.41%**
Loss Factor (%)		3.600%				3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **GS 500 - 4999 kW**

Consumption 2250 kW 400000 kWh

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 1,639.27	1	$ 1,639.27	$ 1,679.12	1	$ 1,679.12	$ 39.85	2.43%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.2966	2250	$ 5,167.35	$ 2.3524	2250	$ 5,292.90	$ 125.55	2.43%
Low Voltage Rate Adder		$ 0.0788	2250	$ 177.30	$ 0.0788	2250	$ 177.30	$ -	0.00%
Volumetric Rate Adder(s)			2250	$ -		2250	$ -	$ -	
Volumetric Rate Rider(s)			2250	$ -		2250	$ -	$ -	
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0111	2250	$ 24.98	$ -	2250	$ -	-$ 24.98	-100.00%
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.9229	2250	-$ 4,326.53	-$ 1.4121	2250	-$ 3,177.23	$ 1,149.30	-26.56%
				$ -			$ -	$ -	
Tax Change	per kW	$ -	2250	$ -	$ -	2250	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 2,682.37**			**$ 3,972.10**	**$ 1,289.73**	**48.08%**
RTSR - Network	per kW	$ 2.5309	2250	$ 5,694.53	$ 2.5309	2250	$ 5,694.53	$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 1.9847	2250	$ 4,465.58	$ 1.9847	2250	$ 4,465.58	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 12,842.47**			**$ 14,132.20**	**$ 1,289.73**	**10.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	414401	$ 2,154.89	$ 0.0052	414401	$ 2,154.89	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	414401	$ 455.84	$ 0.0011	414401	$ 455.84	$ -	0.00%
Special Purpose Charge			414401	$ -		2250	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	400000	$ 2,800.00	$ 0.0070	400000	$ 2,800.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	413651	$ 34,333.03	$ 0.0830	413651	$ 34,333.03	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 52,639.73**			**$ 53,929.45**	**$ 1,289.73**	**2.45%**
HST		13%		$ 6,843.16	13%		$ 7,010.83	$ 167.66	2.45%
Total Bill (including Sub-total B)				**$ 59,482.89**			**$ 60,940.28**	**$ 1,457.39**	**2.45%**
Ontario Clean Energy Benefit [1]				**$ -**			**$ -**	**$ -**	
Total Bill (including OCEB)				**$ 59,482.89**			**$ 60,940.28**	**$ 1,457.39**	**2.45%**
Loss Factor (%)		3.600%			3.60%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **Large Use**

Consumption 5000 kW 3000000 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 12,628.34	1	$ 12,628.34	$ 12,935.32	1	$ 12,935.32	$ 306.98	2.43%
Smart Meter Rate Adder	Monthly		1	$ -		1	$ -	$ -	
Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.7165	5000	$ 13,582.50	$ 2.7825	5000	$ 13,912.50	$ 330.00	2.43%
Low Voltage Rate Adder		$ 0.0841	5000	$ 420.50	$ 0.0841	5000	$ 420.50	$ -	0.00%
Volumetric Rate Adder(s)			5000	$ -		5000	$ -	$ -	
Volumetric Rate Rider(s)			5000	$ -		5000	$ -	$ -	
Smart Meter Disposition Rider			5000	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0035	5000	$ 17.50	$ -	5000	$ -	-$ 17.50	-100.00%
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 2.4898	5000	-$ 12,449.00	-$ 1.9038	5000	-$ 9,519.00	$ 2,930.00	-23.54%
				$ -			$ -	$ -	
Tax Change	per kW	$ -	5000	$ -	$ -	5000	$ -		
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 14,199.84**			**$ 17,749.32**	**$ 3,549.48**	**25.00%**
RTSR - Network	per kW	$ 2.7007	5000	$ 13,503.50	$ 2.7007	5000	$ 13,503.50	$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 2.1197	5000	$ 10,598.50	$ 2.1197	5000	$ 10,598.50	$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 38,301.84**			**$ 41,851.32**	**$ 3,549.48**	**9.27%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	3043500	$ 15,826.20	$ 0.0052	3043500	$ 15,826.20	$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	3043500	$ 3,347.85	$ 0.0011	3043500	$ 3,347.85	$ -	0.00%
Special Purpose Charge			3043500	$ -		5000	$ -	$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	3000000	$ 21,000.00	$ 0.0070	3000000	$ 21,000.00	$ -	0.00%
Energy	per kWh	$ 0.0710	750	$ 53.25	$ 0.0710	750	$ 53.25	$ -	0.00%
Energy	per kWh	$ 0.0830	3042750	$ 252,548.25	$ 0.0830	3042750	$ 252,548.25	$ -	0.00%
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 331,077.64**			**$ 334,627.12**	**$ 3,549.48**	**1.07%**
HST		13%		$ 43,040.09	13%		$ 43,501.53	$ 461.43	1.07%
Total Bill (including Sub-total B)				**$ 374,117.73**			**$ 378,128.65**	**$ 4,010.92**	**1.07%**
Ontario Clean Energy Benefit [1]				**$ -**			**$ -**	**$ -**	
Total Bill (including OCEB)				**$ 374,117.73**			**$ 378,128.65**	**$ 4,010.92**	**1.07%**
Loss Factor (%)		1.4500%			1.4500%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Appendix 2-V
2014 Bill Impacts

Customer Class: **Streetlighting**

	Consumption	**0.1**	**kW**			**33**	**kWh**				
		Current Board-Approved				**Proposed**				**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**		**Rate ($)**	**Volume**	**Charge ($)**		**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 1.52	1	$ 1.52		$ 1.56	1	$ 1.56		$ 0.04	2.63%
Smart Meter Rate Adder			1	$ -			1	$ -		$ -	
Service Charge Rate Adder(s)			1	$ -			1	$ -		$ -	
Service Charge Rate Rider(s)			1	$ -			1	$ -		$ -	
Distribution Volumetric Rate	per kW	$ 12.0916	0.1	$ 1.21		$ 12.3855	0.1	$ 1.24		$ 0.03	2.43%
Low Voltage Rate Adder		$ 0.0582	0.1	$ 0.01		$ 0.0582	0.1	$ 0.01		$ -	0.00%
Volumetric Rate Adder(s)			0.1	$ -			0.1	$ -		$ -	
Volumetric Rate Rider(s)			0.1	$ -			0.1	$ -		$ -	
Smart Meter Disposition Rider			0.1	$ -			1	$ -		$ -	
LRAM & SSM Rate Rider	per kW	$ -	0.1	$ -		$ -	0.1	$ -		$ -	
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 3.0177	0.1	-$ 0.30		-$ 1.1588	0.1	-$ 0.12		$ 0.19	-61.60%
				$ -				$ -		$ -	
Tax Change	per kW	$ -	0.1	$ -		$ -	0.1	$ -			
				$ -				$ -		$ -	
				$ -				$ -		$ -	
Sub-Total A - Distribution				**$ 2.43**				**$ 2.69**		**$ 0.26**	**10.49%**
RTSR - Network	per kW	$ 1.8116	0.1	$ 0.18		$ 1.8116	0.1	$ 0.18		$ -	0.00%
RTSR - Line and Transformation Connection	per kW	$ 1.4666	0.1	$ 0.15		$ 1.4666	0.1	$ 0.15		$ -	0.00%
Sub-Total B - Delivery (including Sub-Total A)				**$ 2.76**				**$ 3.02**		**$ 0.26**	**9.25%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	34	$ 0.18		$ 0.0052	34	$ 0.18		$ -	0.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	34	$ 0.04		$ 0.0011	34	$ 0.04		$ -	0.00%
Special Purpose Charge			34	$ -			0.1	$ -		$ -	
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25		$ 0.2500	1	$ 0.25		$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	34	$ 0.24		$ 0.0070	34	$ 0.24		$ -	0.00%
Energy	per kWh	$ 0.0710	34	$ 2.41		$ 0.0710	34	$ 2.41		$ -	0.00%
Energy	per kWh	$ 0.0830	0	$ -		$ 0.0830	0	$ -		$ -	
				$ -				$ -		$ -	
Total Bill (before Taxes)				**$ 5.88**				**$ 6.13**		**$ 0.26**	**4.34%**
HST		13%		$ 0.76		13%		$ 0.80		$ 0.03	4.34%
Total Bill (including Sub-total B)				**$ 6.64**				**$ 6.93**		**$ 0.29**	**4.37%**
Ontario Clean Energy Benefit [1]				**$ -**				**$ -**		**$ -**	
Total Bill (including OCEB)				**$ 6.64**				**$ 6.93**		**$ 0.29**	**4.37%**
Loss Factor (%)		3.600%				3.60%					

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

Mitigation Plan Approaches

There is no requirement for a mitigation plan because total bill increases for all of the customer classes are less than 10%.

Disposition of Deferral and Variance Accounts

Introduction

The OEB approved Enersource's application for a two-year disposition of Group 1 deferral and variance account balances effective February 1, 2012[1]. The total amount approved for disposition of account balances at December 31, 2010 including interest to January 31, 2012 totalled $40,106. Enersource has not disposed of Group 2 deferral and variance account balances since its 2008 Electricity Distribution Rates cost of service rate application.

Enersource has included in this Application a request for disposition of Group 1 and Group 2 deferral and variance account balances at December 31, 2011 and the forecasted interest through to December 31, 2012. Where regulatory balances requested for disposition differ from the December 31, 2011 financial statements, a reconciliation of the balances is presented.

Enersource is requesting disposition of these deferral and variance account balances, including interest, totalling $907 over a one-year refund period commencing January 1, 2013. This amount excludes the disposition of smart meter balances, which is addressed at Exhibit 9 Tab 2 Schedule 1. Actual interest is based on the Board's prescribed interest rates. The prescribed interest rate for the first quarter of 2012 was used to calculate forecasted interest for the April to December 2012 period. This rate is 1.47%.

[1] EB-2011-0266, Decision dated December 9, 2011. The application was made pursuant to the Board's Report on Electricity Distributors' Deferral and Variance Account Review Initiative (the "EDDVAR Report"), dated July 31, 2009.

Deferral and Variance Accounts Proposed for Disposition

Tables 1 and 2 identify the principal and interest for each deferral and variance account that Enersource is proposing for disposition in this Application, except for deferral accounts 1555 and 1556 relating to smart meters which are treated separately in Exhibit 9 Tab 2 Schedule 1. The principal balances, as of December 31, 2011, are based on Enersource's audited financial statements. Where regulatory balances for certain accounts differ from the corresponding financial statement balance, reconciliation between the two balances is presented. The reconciliation between audited financial statements and regulated financial results can be found in Exhibit 1 Tab 3 Schedule 3.

Enersource has excluded amounts relating to the Group 1 balances that have been approved for disposition, effective February 1, 2012, by the Board in EB-2011-0266, as described above.

Enersource has also excluded Account 1595, Recovery of Regulatory Asset (2009), which represents balances previously approved by the Board for disposition[2] effective February 1, 2010 over a two-year period. Since the disposition period ended January 31, 2012, Enersource is not requesting in this Application the disposition of the remaining account balance in Account 1595 (2009).

[2] EB-2009-0405, Decision dated January 29, 2010.

Table 1: Total Group 1 Account Balances to be Disposed ($000s)

Account Number	Account Description	Principal as of December 31, 2011	Interest to December 31, 2011	Less: Amount Approved for Disposition Effective February 1, 2012	Interest from January 2012 to December 2012	Total to be Disposed
Group 1 Accounts:						
1550	Low Voltage Variance Account	$3,493	$50	$(2,044)	$ 22	$1,521
1580	RSVA – Wholesale Market Service Charges	$(18,204)	$ (274)	$10,633	$ (115)	$ (7,960)
1582	RSVA – One Time Wholesale Market Service	$ -	$29	$ -	$ -	$29
1584	RSVA – Retail Transmission Network	$(5,712)	$(138)	$6,353	$7	$510
1586	RSVA – Retail Transmission Connection	$(4,840)	$(119)	$5414	$7	$461
1588	Power	$4,169	$80	$(3,832)	$6	$423
1588	Power Sub-Account Global Adjustment	$(20,779)	$(445)	$23,298	$30	$2,105
1595	Recovery of Regulatory Asset (2008)	$(203)	$(80)	$284	$ -	$1
	Total Group 1 Accounts to be Disposed:	$(42,076)	$(897)	$40,106	$(43)	$(2,909)
1595	Recovery of Regulatory Asset (2009)	$(2,421)	$106	N/A		
	Total Group 1 Accounts:	**$(44,497)**	**$(791)**	**$40,106**		

RSVA Accounts

The total amount of all RSVA accounts is a $2,909 refund to customers. This group of accounts includes Accounts 1550, 1580, 1582, 1584, 1586, 1588, and 1588 Sub-account Global Adjustment. Enersource has followed the Accounting Procedures Handbook[3] and other OEB-issued guidance to record the variances in these accounts.

Enersource proposes to refund Group 1 balances of $2,909 as detailed above in Table 1, and recover Group 2 balances of $2,002, as detailed below in Table 2. The net Group 1 and Group 2 refund amount of $907, excluding smart meters, is sought to be disposed in this Application. This amount is comprised of a refund

[3] Enersource has followed the Board's *Accounting Procedures Handbook for Electric Distribution Utilities*, revised July 31, 2007. On March 28, 2012, the Board released the *Accounting Procedures Handbook for Electricity Distributors* ("new APH"). Enersource is reviewing the new APH to confirm no changes to the Application are required.

of $3,012 to be allocated to all customer classes and a recovery of $2,105 which relates to the global adjustment variance and therefore only applies to customers that are not on the regulated price plan.

Table 2: Total Group 2 Account Balances to be Cleared ($000s)

Account Number	Account Description	Principal as of December 31, 2011	Interest to December 31, 2011	Interest from January 2012 to December 2012	Adjustments	Total to be Disposed
Group 2 Accounts:						
1508	Other Regulatory Assets – Sub-Account Deferred IFRS Transition Costs	$1490	$27	$22	$50	$1589
1508	Other Regulatory Assets – Sub-Account Deferred Incremental Capital Charges	$44	$1	$1	$ -	$46
1518	Retail Cost Variance Account – Retail	$296	$11	$4	$ -	$312
1548	Retail Cost Variance Account – STR	$316	$25	$5	$ -	$346
1572	Extra-Ordinary Costs (PCBs)	$1211	$26	$18	$ -	$1254
1592	PILs and Tax Variances	$75	$(28)	$(14)	$(1032)	$(998)
1592	PILs and Tax Variances – Sub-Account PST Savings	$(749)	$ -	$	$749	$ -
1592	PILs and Tax Variances – Sub-Account PST Savings (Contra)	$749	$ -	$ -	$(749)	$ -
1592	PILs and Tax Variances – Sub-Account PST Savings (50% portion owing to customers, up to Dec 2012)	$ -	$ -	$ -	$(547)	$(547)
	Total Group 2 Accounts	**$3,433**	**$62**	**$36**	**$(1529)**	**$2002**

Account 1508 Other Regulatory Assets Sub-Account Transition to IFRS

In the Board's *Accounting Procedures Handbook Frequently Asked Questions October 2009* ("APH-FAQ October 2009")[4], the Board permitted the deferral of one-time administrative costs caused by the transition of accounting policies, procedures, systems, and processes to International Financial Reporting Standards ("IFRS") in this sub-account. Based on this guidance, Enersource commenced to defer incremental salaries, wages, and benefits of staff attributable to the transition to IFRS, professional accounting fees, non-capital system and application changes to accommodate IFRS, and staff training costs solely related to IFRS.

Over the three-year period ending December 31, 2011, Enersource has deferred the following IFRS-related amounts and is requesting approval for disposition in this Application to be recovered from customers:

Table 3: Disposal of Account 1508 Sub-Account Transition to IFRS ($000s)

	Actual 2009	Actual 2010	Actual 2011	Subtotal	Interest 2012	Forecast 2012	Total
Salaries, Wages, & Benefits	$ 109	$ 135	$ 188	$ 432			$ 432
Accounting Fees	$ 166	$ 165	$ 107	$ 438		$ 50	$ 488
Non-capital System/Application	$ 183	$ 299	$ 88	$ 570			$ 570
Staff Training & Other	$ 32	$ 10	$ 9	$ 51			$ 51
Subtotal	$ 491	$ 608	$ 391	$ 1,490	$ -	$ 50	$ 1,540
Interest	$	$ 7	$ 20	$ 27	$ 22		$ 49
Total	$ 491	$ 615	$ 411	$ 1,517	$ 22	$ 50	$ 1,589

Enersource confirms that these costs are not already approved and included for recovery in distribution rates. Enersource also confirms that the balance requested for disposition does not include ongoing IFRS compliance costs,

[4] Ontario Energy Board Accounting Procedures Handbook Frequently Asked Questions, October, 2009, p. 4.

impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income, costs related to system upgrades where IFRS was not the major reason for conversion, and costs that are capital in nature.

Account 1508 Other Regulatory Assets Sub-Account Incremental Capital Charges

The amount proposed for clearance in this account is a $46 recovery from customers. As provided in the APH-FAQ October 2009, this account was used by Enersource to record the charges arising from the new Hydro One capital rate relief rider (Rider 5A) charge. Enersource is including the balance in this sub-account for disposition as part of this Application.

Accounts 1518 and 1548 Retail Cost Variance Accounts ("RCVAs")

Accounts 1518 and 1548 capture the difference between the revenue collected from retailers for retail settlement activities and the costs incurred to provide these services. These costs are comprised of incremental salary and benefits of employees directly engaged in retailer billing and information system maintenance costs. The amount requested for disposition relating to the RCVAs is a $658 recovery from customers.

Tables 4 and 5 below identify the costs and revenues recorded in Accounts 1518 and 1548 since the disposition of the 2006 balances.

Table 4: Account 1518 – Retail Cost Variance ($000s)

	2007	2008	2009	2010	2011	2012	Total
Cost	$ 313	$ 310	$ 302	$ 392	$ 392	$ -	$ 1,709
Revenue	(306)	(298)	(293)	(279)	(237)	-	(1,413)
Principal Recorded in Account 1518	7	12	9	113	155	-	296
Interest	5	3	-	-	4	4	16
Total	$ 12	$ 15	$ 9	$ 113	$ 159	$ 4	$ 312

Table 5: Account 1548 – Retail Cost Variance Service Transaction Request ($000s)

	2007	2008	2009	2010	2011	2012	Total
Cost	$ 99	$ 83	$ 51	$ 74	$ 74	$ -	$ 381
Revenue	(22)	(13)	(10)	(13)	(7)	-	(65)
Principal Recorded in Account 1548	77	70	41	61	67	-	316
Interest	10	8	2	2	3	5	30
Total	$ 87	$ 78	$ 43	$ 63	$ 70	$ 5	$ 346

Account 1555 and 1556 Smart Meter Accounts

Enersource is proposing to dispose of its smart meter balances relating to the revenue requirement impact of its Smart Metering Integration Plan ("SMIP") from 2008 to 2011, along with the additional forecasted amounts in 2012 to complete the SMIP. The amounts requested for clearance were not included in rates for those years.

The balance in Account 1555 includes a sub-account for the net book value of stranded conventional meters that were previously included in Enersource's rate

base. This amount is net of all proceeds received from the sale of scrap materials from the stranded conventional meters.

More detailed information relating to Account 1555 and 1556 can be found in Exhibit 9 Tab 2 Schedule 1 and Exhibit 9 Tab 2 Schedule 2.

Account 1572 Extraordinary Event Costs

Enersource is requesting approval for the disposition of Account 1572, with respect to incremental costs incurred relating to new laws pertaining to the use of polychlorinated biphenyls ("PCBs"). The amount requested to be recovered from customers is $1,254.

On September 5, 2008, Environment Canada repealed the "Chlorobiphenyl Regulations" and "Storage of PCB Material Regulations", and made the PCB Regulations (SOR/2008-273) under the *Canadian Environmental Protection Act 1999* ("CEPA") that mandated specific dates for the destruction of PCBs either in storage or in service. Due to the significant costs to comply with these new PCB regulations, which were outside the base upon which rates were derived in Enersource's 2008 cost of service rate application, Enersource requested the approval of a deferral account to record and track these costs. In a letter to Enersource dated December 1, 2008, the Board stated that generic Account 1572, Extraordinary Event Costs, was to be used to address extraordinary costs arising from externalities beyond management's control, and that this account could be used to record and track the incremental PCB environmental compliance program expenses.

The following are paraphrases from the new CEPA regulations with regards to end-of-use dates and extension, and storage end-of-use dates:

PCB End-of-Use Dates and Extension:

- All underground equipment containing PCBs with concentrations of 500 ppm or more must be removed by December 31, 2009. This deadline may be extended by five years, i.e., December 31, 2014, by applying to the Federal Ministry of the Environment;

- Equipment with PCB concentrations less than 500 ppm but more than 50 ppm must be removed by the end of December 31, 2009, if it is in a sensitive place (schools, hospitals, food processing plant, water treatment plants, and senior citizen homes);

- All other underground equipment greater than 50 ppm of PCBs in non-sensitive locations must be removed by December 31, 2025; and

- Replacement of light ballasts and pole top transformers with auxiliary pole mounted equipment with PCB concentration of 50 ppm or more must be done by December 31, 2025.

PCB Storage Deadlines:

- Store until December 31, 2009 if PCBs are sent by that date for destruction to an authorized facility that is authorized for that purpose; or until December 31, 2011 if PCBs are destroyed by that date, at the location where they are stored, in an authorized facility that is authorized for that purpose;

- All the PCB storage sites within 100 m of a sensitive location must be removed by September 5th, 2009;

Maximum storage periods for PCBs and PCB-related products at the following non-sensitive locations:

- One-year at the PCB storage site of an authorized transfer site;

- For processing purposes, one year at owner's PCB storage site; and
- Two years at PCB storage site of an authorized destruction facility.

In order to satisfy the new legislation within the tight timeline and limited resources, Enersource completed an RFP process for the sampling and testing of the equipment. Through this process, a contractor with significant expertise in performing such work was selected.

Enersource's strategy to meet the December 31, 2009 deadline consisted of the inspection of transformers to determine if oil sampling was required, the drawing and testing of the oil samples, the removal and replacement of transformers that did not meet the December 31, 2009 limit, and the disposal of the contaminated transformers and oil.

Throughout this process, Enersource identified Paper Insulated Lead Clad ("PILC") cable in its distribution system, which contains PCBs. Based on the new regulations, Enersource commenced to remove the PILC cables; however, due to limited resources and the location of the cables, a portion of PILC cables remain to be removed and disposed as at December 31, 2011.

Table 6 provides a breakdown of the principal costs incurred, which Enersource is seeking for disposition:

Table 6: Disposal of Account 1572 ($000s)

	Actual 2009	Actual 2010	Actual 2011	Interest 2012	Total
Transformer / Oil	$ 908	$ 51	$ 16	$ -	$ 975
PILC Cables	$ 3	$ 2	$ 231	$ -	$ 236
	$ 911	$ 53	$ 247	$ -	$ 1,211
Interest	$ 2	$ 7	$ 16	$ 18	$ 43
Total	$ 914	$ 60	$ 263	$ 18	$ 1,254

Based on Enersource's analysis of its transformers currently in service, all transformers that do not meet the December 31, 2025 deadline will be replaced before that time due to the normal end of service life. As a result, Enersource does not anticipate incurring additional costs with respect to its transformers, to meet the 2025 requirements.

Account 1592 PILs and Tax Variances

Enersource is requesting approval to dispose of the balance in Account 1592. In the Board's *Accounting Procedures Handbook Frequently Asked Questions December, 2005* ("APH-FAQ December 2005")[5], the Board states that:

> This account will capture the tax impact of the following differences:
>
> • any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model,
>
> • any differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities, and
>
> • any differences in 2006 PILs that result in changes in a distributor's "opening" 2006 balances for tax accounts due to changes in debits and credits to those accounts arising from a tax re-assessment[.]

Enersource has conducted a detailed review of this account, using the APH-FAQ December 2005 as guidance, and has identified amounts that relate to the tax reassessment of the 2003 to 2006 taxation years which do not meet the guidelines for this account. Enersource is proposing to exclude these balances from the disposition amount. As a result, the amount to be disposed of is a refund to customers of $998.

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[5] Ontario Energy Board Accounting Procedures Handbook Frequently Asked Questions, December, 2005, p. 13.

Table 7: Disposal of Account 1592 ($000s)

	Balance at December 31, 2011	Adjustment	Revised Balance at December 31, 2011	Interest from January 2012 to December 2012	Balance to be Disposed
Principal	$ 75	$ (1,003)	$ (928)	$ -	$ (928)
Interest	$ (28)	$ (29)	$ (57)	$ (14)	$ (71)
	$ 48	$ (1,032)	$ (985)	$ (14)	$ (998)

The principal balance of $928 to be refunded relates to the impact of the decrease in Ontario Capital Tax rates in 2007 and 2008, and the decrease of income tax rates in 2008 and 2009. Refer to Exhibit 9 Tab 1 Schedule 1 Appendix 2-T Deferred PILs Account 1592 Balances for detailed calculations.

Account 1592 PILs and Tax Variances Sub-account

HST/OVAT Input Tax Credits ("ITCs")

In the Supplementary Decision and Order[6] with respect to Enersource's third generation incentive regulation mechanism ("3rd GIRM") application for distribution rates to be effective May 1, 2010, the Board stated the following:

> *"The Board therefore directs that, beginning July 1, 2010, Enersource shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs)), the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of Enersource's*

[6] EB-2009-0193 Supplementary Decision and Order, dated March 29, 2010, p. 5.

next cost of service rate order. 50 % [sic] of the confirmed balances in the account shall be returnable to the ratepayers.

The Board may issue more detailed accounting guidance in the future. In that event, the Applicant should make the appropriate accounting entries, if and as applicable."

In the APH-FAQ December 2010, the Board identified an alternative method that distributors may use to calculate savings as a result of the transition to Harmonized Sales Tax ("HST"). This method uses an historic year as a proxy to estimate the savings from July 1, 2010 to the distributor's next cost of service rate application.

Enersource used 2009 as its proxy, whereby the Provincial Sales Tax ("PST") paid during that year was used as an estimate of the PST included in operating and capital spending that would be removed by the elimination of PST, effective July 1, 2010 to December 31, 2012.

Table 8 below identifies the PST paid on Enersource's 2009 operating costs and the estimated savings from July 1, 2010 to December 31, 2012.

Table 8: Estimated Savings on Operating Costs ($000s)

			Estimated Savings			
	2009 PST Eligible Operating Expense	PST Paid	July to December 2010	2011	2012	Total Savings on Operating Costs
Material / Consumables	$ 1,597	$ 128				
Information Technology	$ 1,564	$ 125				
Communications	$ 819	$ 66				
Other	$ 547	$ 44				
Total	$ 4,527	$ 362	$ 181	$ 362	$ 362	$ 905

In determining the estimated savings on capital costs using 2009 as a proxy, Enersource has excluded one-time costs incurred in 2009 pertaining to the implementation of its customer care and billing system ("CC&B"). These costs do not recur in future years and therefore, because Enersource does not realize any savings on these amounts from 2010 onwards, they have been removed from the proxy amount. The following Table 9 identifies the PST paid on Enersource's 2009 capital costs and the estimated savings from July 1, 2010 to December 31, 2012.

Table 9: Estimated Savings on Capital Costs ($000s)

					Estimated Savings			
	2009 PST Eligible Capital Cost	PST Paid	Estimated Asset Life	Annual Depreciation of PST	July to December 2010	2011	2012	Total Savings on Capital Costs
Building	$ 3	$	60	$				
Computer Equipment	$ 906	$ 73	5	$ 15				
Major Tools	$ 234	$ 19	10	$ 2				
Meters	$ 457	$ 37	25	$ 1				
Office Equipment	$ 47	$ 4	10	$				
Overhead	$ 3,250	$ 260	50	$ 5				
Rolling Stock	$ 1,733	$ 139	8	$ 17				
Rolling Stock	$ 72	$ 6	5	$ 1				
Smart Meters	$ 5,223	$ 418	15	$ 28				
Software	$ 366	$ 29	2	$ 15				
Software	$ 335	$ 22	10	$ 2				
Substation Equipment	$ 2,820	$ 226	40	$ 6				
Supervisory Controls	$ 540	$ 43	15	$ 3				
Underground	$ 3,860	$ 309	40	$ 8				
	$ 19,847	$ 1,583		$ 103	$ 51	$ 154	$ 257	$ 463

As part of the transition to HST, the Canada Revenue Agency ("CRA") and the Ontario Ministry of Revenue require large businesses to repay or recapture input tax credits ("RITCs") attributable to the provincial component of HST in respect of specified property and services required for use by that business.

The specified property and services include:

a) specified road vehicles and the fuel used in the vehicles;

b) specified energy;

c) specified telecommunication services; and

d) specified meals and entertainment.

The guidance provided by the Board is very brief on the recapture of input tax credits with respect to the amount to be tracked in the deferral account.

The APH-FAQ December 2010 states[7]:

Q.3 Should a distributor record in the sub-account the incremental HST on items not previously subject to PST, such as natural gas and electricity utility costs that became subject to the HST at 13% but are subject to recaptured ITC requirements, thus nullifying the ITCs?

A.3 No, for the same reason as noted in A.2 above.

Question 2 from the same documents states:

Q.2 Should a distributor record in the sub-account ITCs received on items such as legal and audit fees, which were not previously subject to PST but now are subject to HST and eligible to receive ITCs?

A.2 No. These ITCs relate to expense items that were not previously subject to PST and they are therefore not incremental ITCs to be recorded in the sub-account.

Enersource believes that the estimated PST savings tracked in the deferral account should be reduced by the estimated RITCs. The RITCs represent a true

[7] APH-FAQ December 2010, at pages 3-4.

expense to a distributor and therefore the reduction of the PST savings amount by the estimated RITCs more appropriately reflects the estimated savings from the transition to HST.

It must be noted that Enersource did apply for para-municipal status for HST purposes which would have eliminated the RITC requirement; however the request was denied by the CRA. In the CRA's response, it was stated that Enersource Corporation received para-municipal status, as it is 90% owned by the City of Mississauga. Enersource Corporation is a separate legal entity from the City of Mississauga and therefore, Enersource Hydro Mississauga Inc. (100% owned by Enersource Corporation) has been created by one municipal body and is owned by another. As a result, the CRA concluded, Enersource Hydro Mississauga Inc. is not directly controlled by the City of Mississauga and, therefore, Enersource Hydro Mississauga Inc. does not meet the administrative policy and eligibility requirements to become a para-municipal organization.

Enersource has calculated the estimated RITCs based on using 2009 as a proxy, which is detailed in Table 10 below:

Table 10: Estimated RITCs ($000s)

		July - December 2010	2011	2012	Total
Communication		$ 7	$ 15	$ 15	$ 37
Utilities		$ 33	$ 66	$ 66	$ 164
Fuel		$ 16	$ 33	$ 33	$ 82
Meals		$ 2	$ 4	$ 4	$ 10
		$ 59	$ 117	$ 117	$ 293

Based on the above, Enersource is proposing to refund to customers $547, inclusive of the amount of PST savings pertaining to 2012 and interest. See Table 11 below.

Table 11: Disposal of Account 1592 PILs and Tax Variances Sub-account HST/OVAT ITCs ($000s)

Estimated PST Savings on Operating Costs (July 2010 to December 2012)	$	905
Estimated PST Savings on Capital Costs (July 2010 to December 2012)	$	463
Estimated RITCs (July 2010 to December 2012)	$	(293)
	$	1,076
	$	
50% to be returned to customers	$	538
Interest from July 1 2010 to December 31, 2012	$	9
Total to be returned to customers	$	547

Enersource has calculated the amount to be refunded to customers in accordance with the Board's guidance; however, Enersource disagrees with including estimated PST savings on capital expenditures in the calculation.

Enersource's last cost of service rate application was for the 2008 rate year, and it has been adjusting rates pursuant to incentive regulation mechanism ("IRM") from 2009 to 2012. Under an IRM rate-setting year, distribution rates are set based on the last Board-approved revenue requirement and adjusted by the Board-issued inflation index. As Enersource's rate base was last approved in 2008, before the implementation of HST, the depreciation approved in the cost of service, and inherent in the IRM, is reflective of the costs of the assets up to 2008, including any associated PST actually incurred.

Under IRM, the depreciation recovery amount does not change or get updated to reflect actual increases in rate base each year. Therefore, the depreciation recovered in rates under IRM is significantly lower than actual depreciation incurred. Any potential PST savings in capital purchases after July 1, 2010 is

minimal compared to the actual depreciation expense increases resulting from replacing fully depreciated assets, purchased decades earlier at a much lower cost, with new and more expensive assets.

Other Amounts to be Disposed

In addition to the clearance of the deferral and variance accounts, Enersource is seeking to refund/recover the following items:

Deferred IFRS Adjustment

Enersource adopted IFRS on January 1, 2012. As part of the transition, Enersource must also present prior year comparative financial information under IFRS. As a result, the effective date of transition to IFRS is January 1, 2011. Since the OEB-modified IFRS ("MIFRS") value of fixed assets is to be used in determining rate base on a go-forward basis, the differences relating to the treatment of fixed assets between CGAAP and MIFRS for 2011 and 2012 under an IRM period are to be recovered or refunded to customers.

A detailed explanation of the impact of transitioning to MIFRS relating to fixed assets can be found in Exhibit 2 Tab 1 Schedule 1. The following Table 12 summarizes the financial impact on fixed assets, which Enersource is requesting to refund to customers.

Table 12: Impact of MIFRS on Fixed Assets ($000s)

	2011	2012	Total
Change of Useful Lives of Assets	$ (10,734)	$ (11,030)	$ (21,764)
Overhead Capitalization	$ 2,525	$ 3,022	$ 5,547
Early Derecognition of Assets	$ 1,859	$ 1,924	$ 3,783
Reduction in Depreciation due to Burdens & Derecognition	$ (94)	$ (292)	$ (386)
Total	$ (6,444)	$ (6,377)	$ (12,821)

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.

Approval for New Deferral and Variance Accounts

Enersource is seeking approval to create two new sub-accounts to Account 1595 to record the recovery and refunds pertaining to the disposition of the deferral and variance accounts at December 31, 2011. The first sub-account would be for the recovery of the Global Adjustment sub-account and the second for the refund of all of the other deferral and variance accounts. Upon approval of the disposition by the Board, Enersource would transfer the approved amounts from the respective deferral and variance accounts to the corresponding sub-accounts of 1595. Amounts billed or credited through the rate riders would then be recorded as offsetting entries.

Enersource is also seeking approval for two new deferral and variance accounts as part of the transition to MIFRS. Enersource is proposing that an account be created to track variances between the amount approved to be refunded to customers for the impact of MIFRS on fixed assets and the amount billed. A second deferral account is requested which is to be used for future re-measurements of the defined benefit obligation which will be recorded in other comprehensive income instead of being amortized in OM&A.

Reporting and Record-Keeping Requirements

On February 29, 2012, Enersource filed with the Board the balances for each of the deferral and variance accounts recorded to December 31, 2011 as required by the Reporting and Record-keeping Requirements ("RRR"). Deferral and variance account balances proposed for disposition in this application agree with the amounts filed, other than the inclusion of forecasted interest from January 1, 2012 to December 31, 2012.

Calculation of Rate Riders for Recovery

Table 15 below shows the proposed rate riders to clear the balances requested for disposition. The proposed rate riders consist of:

- Rate Rider # 1 – includes disposition of Groups 1 and 2 deferral and variance accounts, refund of MIFRS deferred adjustment, and recovery of OCI MIFRS post-employment adjustment which are applicable to all customers;
- Rate Rider # 2 – Disposition of Global Adjustment Sub-Account applicable to non-regulated price plan customers;
- Rate Rider # 3 – Disposition of stranded meter balance; and
- Rate Rider # 4 – Smart Meter Disposition Rate Rider.

The worksheet for determining the rate riders is included in Exhibit 9 Tab 1 Schedule 1 Appendix 3. This worksheet allocates the variance and deferral accounts to each customer class. Enersource proposes the same allocators be used for the accounts as specified in the EDDVAR report.

For Rate Rider # 1, rate riders for the Residential, General Service<50 kW, and USL classes are determined by dividing the disposition amount by the 2013 forecasted annual load in kWh for that class. For the remaining customer classes, the 2013 forecasted annual demand in kW were used to determine the rate rider. Rate Rider # 1 will be presented on the customer bill as part of the variable distribution charge for each class.

Rate Rider # 2 is determined by dividing the total balance to be recovered for the global adjustment variance by the applicable forecasted load in kWh or kW for non-RPP customers in 2013. This methodology is consistent with the approved disposition of the global adjustment balance in EB-2011-0266[8].

Rate Riders # 3 and #4 are determined based on the forecasted average number of customers in the customer classes that were part of the smart meter

[8] Enersource's EDDVAR application, EB-2011-0266, Decision dated December 9, 2011.

deployment. These are Residential, General Service<50 kW, and General Service 50 – 499 kW.

Table 15: Proposed Rate Riders for Disposition of Deferral and Variance Accounts Effective January 1, 2013 to December 31, 2013

Deferral and Variance Account Disposition Rate Rider	Variable Distribution Rate	Rate Rider # 1 All Customers	Rate Rider # 2 Non-RPP Customers	Low Voltage Service Charge
Residential	kWh	(0.0035)	0.0005	0.0002
General Service < 50 kW	kWh	(0.0033)	0.0005	0.0002
Unmetered Scattered Load	kWh	(0.0057)	0.0004	0.0002
General Service 50 kW - 499 kW	kW	(0.7170)	0.1365	0.0805
General Service 500 kW - 4999 kW	kW	(0.6377)	0.1740	0.0788
Large Use (> 5000 kW)	kW	(0.7701)	0.2306	0.0841
Street Lighting	kW	(1.8174)	0.1422	0.0582
Deferral and Variance Account Disposition Rate Rider	**Fixed**	**Rate Rider # 3**	**Rate Rider # 4**	
Residential	Monthly	3.23	0.13	
General Service < 50 kW	Monthly	3.40	0.13	
General Service 50 kW - 499 kW	Monthly	1.22	0.13	

Implementation

Enersource requests that the rate order from the Board set out rate riders to be effective for a period of one year from January 1, 2013 to December 31, 2013.

Bill Impacts

For a complete analysis of bill impacts, please see Exhibit 8 Tab 9 Schedule 1.

Deferral and Variance Account Balances Continuity

Account Description	Note	Account Number	Principal Balance Jan 1-08	Opening Interest Jan 1-08	Principal Additions Jan 1-08 to Dec 31-08	Interest Additions Jan 1-08 to Dec 31-08	Transfer of Board Approved Principal	Transfer of Board Approved Interest	Principal Balance Dec 31-08	Closing Interest Dec 31-08	Total Balance Dec 31-08
			A	B	C	D	E	F	G=A+C+E	H=B+D+F	I=G+H
Group 1 Accounts											
LV Variance Account		1550	(712,150)	(23,047)	73,421	(29,760)	-		(638,729)	(52,807)	(691,536)
RSVA - Wholesale Market Service Charge		1580	(15,011,668)	(252,080)	(4,422,511)	(594,983)	4,628,574	(183,683)	(14,805,605)	(1,030,746)	(15,836,351)
RSVA - One-time		1582	437,418	109,500	-	8,595	(437,418)	(88,902)	-	29,193	29,193
RSVA - Retail Transmission Network Charge		1584	2,582,508	75,593	(3,578,960)	(4,774)	(1,410,556)	29,018	(2,407,008)	99,837	(2,307,171)
RSVA - Retail Transmission Connection Charge		1586	(1,150,065)	(481,270)	(2,141,653)	(33,306)	2,403,900	398,216	(887,817)	(116,360)	(1,004,178)
RSVA - Power (excluding Global Adjustment)		1588	(11,277,089)	(945,526)	3,482,497	(290,070)	5,582,213	667,465	(2,212,378)	(568,130)	(2,780,509)
RSVA - Power - Sub-Account - Global Adjustment		1588	3,265,394	(72,615)	4,061,908	143,943			7,327,302	71,328	7,398,630
Recovery of Regulatory Asset Balances		1590	2,039,904	1,611,824	4,914,216	48,351	(7,021,130)	(1,618,861)	(67,009)	41,313	(25,696)
Disposition and Recovery of Regulatory Balances (2008)		1595							-	-	-
Group 1 Subtotal			(19,825,747)	22,380	2,388,920	(752,005)	3,745,583	(796,747)	(13,691,244)	(1,526,372)	(15,217,617)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	942,688	145,968	-	15,248	(942,688)	(161,216)	-	-	-
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	1,371,737	183,172	-	22,132	(1,371,737)	(205,304)	-	-	-
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs		1508	-	-	-	-	-	-	-	-	-
Other Regulatory Assets - Sub-Account - Incremental Capital Charges		1508	-	-	-	-	-	-	-	-	-
Retail Cost Variance Account - Retail		1518	113,563	12,271	12,065	2,669	(106,705)	(7,396)	18,923	7,544	26,467
Misc. Deferred Debits		1525	21,095	1,730	-	322	(21,095)	(2,052)	-	-	-
Retail Cost Variance Account - STR		1548	250,466	25,624	69,684	7,769	(173,008)	(15,710)	147,142	17,683	164,825
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	(1)	1555	7,623,696	-	-	-	-	-	7,623,696	-	7,623,696
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	(1)	1555	(2,566,971)	(63,154)	(1,805,342)	(138,437)	1,007,248	-	(3,365,065)	(201,591)	(3,566,656)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	(1)	1555	1,820,847	-	2,106,568	-	-	-	3,927,415	-	3,927,415
Smart Meter OM&A Variance	(1)	1556	-	-	-	-	-	-	-	-	-
Deferred Payments in Lieu of Taxes	(2)	1562	-	-	-	-	-	-	-	-	-
Extraordinary Event Losses (PCBs)		1572	-	-	-	-	-	-	-	-	-
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)		1592	(385,891)	2,878	(357,979)	(20,951)	32,897	(2,420)	(710,973)	(20,493)	(731,466)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)		1592	-	-	-	-	-	-	-	-	-
Special Purpose Charge Assessment Variance Account		1521									
Group 2 Subtotal - including 1521			9,191,230	308,489	24,996	-111,248	-1,575,088	-394,098	7,641,138	-196,857	7,444,281
Total Group 1 and 2			-10,634,517	330,869	2,413,916	-863,253	2,170,495	-1,190,845	-6,050,106	-1,723,229	-7,773,336
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account	(2)	1563									
Board-Approved CDM Variance Account		1567									
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account		1592	-	-	-	-	-	-	-	-	-
Disposition and Recovery of Regulatory Balances (2011)		1595									
Disposition and Recovery of Regulatory Balances (2009)		1595							-	-	-

Note 1 - Refer to Exhibit 9 Tab 2 for the disposition of smart meter balances.
Note 2 - Enersource applied for disposition of Account 1562 in its 2012 IRM; EB-2011-0100.

Deferral and Variance Account Balances Continuity

Account Description	Note	Account Number	Principal Balance Jan 1-09	Opening Interest Jan 1-09	Principal Additions Jan 1-09 to Dec 31-09	Interest Additions Jan 1-09 to Dec 31-09	Transfer of Board Approved Principal	Transfer of Board Approved Interest	Principal Balance Dec 31-09	Closing Interest Dec 31-09	Total Balance Dec 31-09
			J	K	L	M	N	O	P=J+L+N	Q=K+M+O	R=P+Q
Group 1 Accounts											
LV Variance Account		1550	(638,729)	(52,807)	861,469	(7,007)			222,740	(59,814)	162,926
RSVA - Wholesale Market Service Charge		1580	(14,805,605)	(1,030,746)	(2,150,637)	(174,374)			(16,956,242)	(1,205,120)	(18,161,362)
RSVA - One-time		1582	-	29,193	-	-			-	29,193	29,193
RSVA - Retail Transmission Network Charge		1584	(2,407,008)	99,837	(3,234,831)	(33,346)			(5,641,839)	66,491	(5,575,348)
RSVA - Retail Transmission Connection Charge		1586	(887,817)	(116,360)	(2,708,697)	(14,429)			(3,596,514)	(130,789)	(3,727,304)
RSVA - Power (excluding Global Adjustment)		1588	(2,212,378)	(568,130)	(2,687,647)	(60,019)			(4,900,025)	(628,150)	(5,528,175)
RSVA - Power - Sub-Account - Global Adjustment		1588	7,327,302	71,328	29,771,228	207,972			37,098,531	279,300	37,377,830
Recovery of Regulatory Asset Balances		1590	(67,009)	41,313					(67,009)	41,313	(25,696)
Disposition and Recovery of Regulatory Balances (2008)		1595	-	-	(203,108)	(76,154)			(203,108)	(76,154)	(279,262)
Group 1 Subtotal			(13,691,244)	(1,526,372)	19,647,777	(157,357)	-	-	5,956,533	(1,683,729)	4,272,804
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	-	-	-	-			-	-	-
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	-	-	-	-			-	-	-
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs		1508	-	-	490,588	345			490,588	345	490,933
Other Regulatory Assets - Sub-Account - Incremental Capital Charges		1508	-	-	28,559	19			28,559	19	28,578
Retail Cost Variance Account - Retail		1518	18,923	7,544	8,267	275			27,190	7,819	35,009
Misc. Deferred Debits		1525	-	-	-	-			-	-	-
Retail Cost Variance Account - STR		1548	147,142	17,683	40,799	1,781			187,941	19,464	207,405
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	**(1)**	1555	7,623,696	-	-	-			7,623,696	-	7,623,696
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	**(1)**	1555	(3,365,065)	(201,591)	(2,586,505)	(44,518)			(5,951,570)	(246,109)	(6,197,679)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	**(1)**	1555	3,927,415	-	3,634,866	-			7,562,281	-	7,562,281
Smart Meter OM&A Variance	**(1)**	1556	-	-	-	-			-	-	-
Deferred Payments in Lieu of Taxes	**(2)**	1562	-	-	-	-			-	-	-
Extraordinary Event Losses (PCBs)		1572	-	-	911,330	2,263			911,330	2,263	913,593
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)		1592	(710,973)	(20,493)	649,001	(8,234)			(61,972)	(28,727)	(90,699)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)		1592	-	-	-	-			-	-	-
Special Purpose Charge Assessment Variance Account		1521									
Group 2 Subtotal - including 1521			7,641,138	-196,857	3,176,905	-48,069	0	0	10,818,043	-244,926	10,573,117
Total Group 1 and 2			-6,050,106	-1,723,229	22,824,682	-205,426	0	0	16,774,576	-1,928,655	14,845,921
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account	**(2)**	1563									
Board-Approved CDM Variance Account		1567									
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account		1592	-	-	-	-	-	-	-	-	-
Disposition and Recovery of Regulatory Balances (2011)		1595									
Disposition and Recovery of Regulatory Balances (2009)		1595	-	-					-	-	-

Note 1 - Refer to Exhibit 9 Tab 2 for the disposition of smart meter balances.
Note 2 - Enersource applied for disposition of Account 1562 in its 2012 IRM; EB-2011-0100.

Deferral and Variance Account Balances Continuity

Account Description	Note	Account Number	Principal Balance Jan 1-10	Opening Interest Jan 1-10	Principal Additions Jan 1-10 to Dec 31-10	Interest Additions Jan 1-10 to Dec 31-10	Transfer of Board Approved Principal	Transfer of Board Approved Interest	Principal Balance Dec 31-10	Closing Interest Dec 31-10	Total Balance Dec 31-10
			S	T	U	V	W	X	Y=S+U+W	Z=T+V+X	AA=Y+Z
Group 1 Accounts											
LV Variance Account		1550	222,740	(59,814)	1,138,581	11,119	638,728	60,322	2,000,049	11,627	2,011,676
RSVA - Wholesale Market Service Charge		1580	(16,956,242)	(1,205,120)	(8,250,747)	(65,701)	14,805,516	1,205,024	(10,401,473)	(65,797)	(10,467,270)
RSVA - One-time		1582	-	29,193	-	-	-	-	-	29,193	29,193
RSVA - Retail Transmission Network Charge		1584	(5,641,839)	66,491	(2,977,424)	(36,520)	2,407,008	(71,518)	(6,212,255)	(41,547)	(6,253,802)
RSVA - Retail Transmission Connection Charge		1586	(3,596,514)	(130,789)	(2,584,800)	(32,418)	887,818	126,805	(5,293,496)	(36,402)	(5,329,899)
RSVA - Power (excluding Global Adjustment)		1588	(4,900,025)	(628,150)	366,530	12,353	8,288,868	633,010	3,755,373	17,213	3,772,586
RSVA - Power - Sub-Account - Global Adjustment		1588	37,098,531	279,300	(18,434,026)	(90,778)	(41,485,837)	(301,804)	(22,821,333)	(113,282)	(22,934,615)
Recovery of Regulatory Asset Balances		1590	(67,009)	41,313		(789)	67,009	(40,524)	-	-	-
Disposition and Recovery of Regulatory Balances (2008)		1595	(203,108)	(76,154)		(1,182)			(203,108)	(77,336)	(280,444)
Group 1 Subtotal			5,956,533	(1,683,729)	(30,741,886)	(203,916)	(14,390,890)	1,611,315	(39,176,243)	(276,331)	(39,452,574)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	-	-	-	-	-	-	-	-	-
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	-	-	-	-	-	-	-	-	-
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs		1508	490,588	345	608,267	6,928	-	-	1,098,855	7,273	1,106,128
Other Regulatory Assets - Sub-Account - Incremental Capital Charges		1508	28,559	19	15,478	345	-	-	44,037	364	44,401
Retail Cost Variance Account - Retail		1518	27,190	7,819	113,283	290	-	-	140,473	8,109	148,582
Misc. Deferred Debits		1525	-	-	-	-	-	-	-	-	-
Retail Cost Variance Account - STR		1548	187,941	19,464	61,240	1,653	-	-	249,181	21,117	270,298
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	(1)	1555	7,623,696	-	-	-	-	-	7,623,696	-	7,623,696
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	(1)	1555	(5,951,570)	(246,109)	(4,435,713)	(65,135)	-	-	(10,387,283)	(311,244)	(10,698,527)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	(1)	1555	7,562,281	-	2,920,894	-	-	-	10,483,175	-	10,483,175
Smart Meter OM&A Variance	(1)	1556	-	-	-	-	-	-	-	-	-
Deferred Payments in Lieu of Taxes	(2)	1562	-	-	-	-	-	-	-	-	-
Extraordinary Event Losses (PCBs)		1572	911,330	2,263	52,704	7,396	-	-	964,034	9,659	973,693
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)		1592	(61,972)	(28,727)	137,403	(250)	-	-	75,431	(28,977)	46,454
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)		1592	-	-	(232,536)	-	-	-	(232,536)	-	(232,536)
Special Purpose Charge Assessment Variance Account		1521	-	-	(158,872)	20,486	-	-	(158,872)	20,486	(138,386)
Group 2 Subtotal - including 1521			10,818,043	-244,926	-917,852	-28,287	0	0	9,900,191	-273,213	9,626,978
Total Group 1 and 2			16,774,576	-1,928,655	-31,659,738	-232,203	-14,390,890	1,611,315	-29,276,052	-549,544	-29,825,596
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account	(2)	1563									
Board-Approved CDM Variance Account		1567									
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account		1592	-	-	232,536	-	-	-	232,536	-	232,536
Disposition and Recovery of Regulatory Balances (2011)		1595									
Disposition and Recovery of Regulatory Balances (2009)		1595	-	-	(7,429,328)	69,867	12,779,575		5,350,247	69,867	5,420,114

Note 1 - Refer to Exhibit 9 Tab 2 for the disposition of smart meter balances.
Note 2 - Enersource applied for disposition of Account 1562 in its 2012 IRM; EB-2011-0100.

Deferral and Variance Account Balances Continuity

Account Description	Note	Account Number	Principal Balance Jan 1-11	Opening Interest Jan 1-11	Principal Additions Jan 1-11 to Dec 31-11	Interest Additions Jan 1-11 to Dec 31-11	Transfer of Board Approved Principal	Transfer of Board Approved Interest	Principal Balance Dec 31-11	Closing Interest Dec 31-11	Total Balance Dec 31-11
			BB	CC	DD	EE	FF	GG	HH=BB+DD+FF	II=CC+EE+GG	JJ=HH+II
Group 1 Accounts											
LV Variance Account		1550	2,000,049	11,627	1,492,594	38,470			3,492,643	50,097	3,542,740
RSVA - Wholesale Market Service Charge		1580	(10,401,473)	(65,797)	(7,802,501)	(208,490)			(18,203,974)	(274,287)	(18,478,261)
RSVA - One-time		1582	-	29,193	-	-			-	29,193	29,193
RSVA - Retail Transmission Network Charge		1584	(6,212,255)	(41,547)	499,949	(96,477)			(5,712,306)	(138,024)	(5,850,330)
RSVA - Retail Transmission Connection Charge		1586	(5,293,496)	(36,402)	453,081	(82,842)			(4,840,415)	(119,244)	(4,959,660)
RSVA - Power (excluding Global Adjustment)		1588	3,755,373	17,213	413,948	63,195			4,169,321	80,408	4,249,729
RSVA - Power - Sub-Account - Global Adjustment		1588	(22,821,333)	(113,282)	2,042,513	(331,638)			(20,778,820)	(444,920)	(21,223,740)
Recovery of Regulatory Asset Balances		1590	-	-					-	-	-
Disposition and Recovery of Regulatory Balances (2008)		1595	(203,108)	(77,336)		(2,170)			(203,108)	(79,506)	(282,614)
Group 1 Subtotal			(39,176,243)	(276,331)	(2,900,416)	(619,952)	-	-	(42,076,659)	(896,283)	(42,972,942)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	-	-	-	-			-	-	-
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	-	-	-	-			-	-	-
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs		1508	1,098,855	7,273	391,149	19,693			1,490,004	26,966	1,516,970
Other Regulatory Assets - Sub-Account - Incremental Capital Charges		1508	44,037	364	-	647			44,037	1,011	45,048
Retail Cost Variance Account - Retail		1518	140,473	8,109	155,703	3,041			296,176	11,150	307,326
Misc. Deferred Debits		1525	-	-	-	-			-	-	-
Retail Cost Variance Account - STR		1548	249,181	21,117	67,243	4,113			316,424	25,230	341,654
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	**(1)**	1555	7,623,696	-	-	-			7,623,696	-	7,623,696
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	**(1)**	1555	(10,387,283)	(311,244)	(4,999,983)	(186,535)			(15,387,266)	(497,779)	(15,885,045)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	**(1)**	1555	10,483,175	-	(3,048,353)	-			7,434,822	-	7,434,822
Smart Meter OM&A Variance	**(1)**	1556	-	-	-	-			-	-	-
Deferred Payments in Lieu of Taxes	**(2)**	1562	-	-	-	-			-	-	-
Extraordinary Event Losses (PCBs)		1572	964,034	9,659	246,807	15,965			1,210,841	25,624	1,236,465
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)		1592	75,431	(28,977)	-	1,109			75,431	(27,868)	47,563
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)		1592	(232,536)	-	(516,511)	-			(749,047)	-	(749,047)
Special Purpose Charge Assessment Variance Account		1521	(158,872)	20,486	-	-			(158,872)	20,486	(138,386)
Group 2 Subtotal - including 1521			9,900,191	-273,213	-7,703,945	-141,967	0	0	2,196,246	-415,180	1,781,066
Total Group 1 and 2			-29,276,052	-549,544	-10,604,361	-761,919	0	0	-39,880,413	-1,311,462	-41,191,876
The following is not included in the total claim but are included on a memo basis:											
Deferred PILs Contra Account	**(2)**	1563									
Board-Approved CDM Variance Account		1567									
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account		1592	232,536	-	516,511	-	-	-	749,047	-	749,047
Disposition and Recovery of Regulatory Balances (2011)		1595									
Disposition and Recovery of Regulatory Balances (2009)		1595	5,350,247	69,867	(7,772,241)	36,648	-		(2,421,994)	106,515	(2,315,479)

Note 1 - Refer to Exhibit 9 Tab 2 for the disposition of smart meter balances.
Note 2 - Enersource applied for disposition of Account 1562 in its 2012 IRM; EB-2011-0100.

Deferral and Variance Account Balances Continuity

1.47%

Account Description	Note	Account Number	Principal Balance Jan 1-12	Opening Interest Jan 1-12	Transfer of Board Approved Principal	Transfer of Board Approved Interest	2012 IRM - Principal	2012 IRM - Interest	Forecasted Interest Additions Jan 1-12 to Dec 31-12	Principal Adjustment Jan 1-12 to Dec 31-12	Interest Adjustment Jan 1-12 to Dec 31-12	Principal Balance to be Disposed Dec 31-12	Interest to be Disposed Dec 31-12	Total Balance to be Disposed Dec 31-12
			KK	LL	MM	NN	OO	PP	QQ	RR	SS	TT = KK+MM+OO+RR	UU = LL+NN+PP+QQ+SS	
Group 1 Accounts														
LV Variance Account		1550	3,492,643	50,097	(2,000,049)	(43,517)			21,941			1,492,594	28,521	1,521,115
RSVA - Wholesale Market Service Charge		1580	(18,203,974)	(274,287)	10,401,473	231,638			(114,697)			(7,802,501)	(157,346)	(7,959,846)
RSVA - One-time		1582	-	29,193	-	-			-			-	29,193	29,193
RSVA - Retail Transmission Network Charge		1584	(5,712,306)	(138,024)	6,212,255	140,595			7,349			499,949	9,921	509,870
RSVA - Retail Transmission Connection Charge		1586	(4,840,415)	(119,244)	5,293,496	120,802			6,660			453,081	8,218	461,299
RSVA - Power (excluding Global Adjustment)		1588	4,169,321	80,408	(3,755,373)	(77,088)			6,085			413,948	9,405	423,353
RSVA - Power - Sub-Account - Global Adjustment		1588	(20,778,820)	(444,920)	22,821,333	477,146			30,025			2,042,514	62,251	2,104,764
Recovery of Regulatory Asset Balances		1590	-	-					-			-	-	-
Disposition and Recovery of Regulatory Balances (2008)		1595	(203,108)	(79,506)	203,108	80,574			-			-	1,068	1,068
Group 1 Subtotal			(42,076,659)	(896,283)	39,176,243	930,150			(42,636)			(2,900,416)	(8,769)	(2,909,185)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	-	-	-	-			-			-	-	-
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	-	-	-	-			-			-	-	-
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs		1508	1,490,004	26,966	-	-			21,903	50,000		1,540,004	48,869	1,588,873
Other Regulatory Assets - Sub-Account - Incremental Capital Charges		1508	44,037	1,011	-	-			647			44,037	1,658	45,695
Retail Cost Variance Account - Retail		1518	296,176	11,150	-	-			4,354			296,176	15,504	311,680
Misc. Deferred Debits		1525	-	-	-	-			-			-	-	-
Retail Cost Variance Account - STR		1548	316,424	25,230	-	-			4,651			316,424	29,881	346,305
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	(1)	1555												
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	(1)	1555												
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	(1)	1555												
Smart Meter OM&A Variance	(1)	1556	-	-	-	-			-			-	-	-
Deferred Payments in Lieu of Taxes	(2)	1562	-	-	-	-			-			-	-	-
Extraordinary Event Losses (PCBs)		1572	1,210,841	25,624	-	-			17,799	-		1,210,841	43,423	1,254,264
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)		1592	75,431	(27,868)	-	-			(13,637)	(1,003,087)	(29,016)	(927,656)	(70,521)	(998,177)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)		1592	(749,047)	-	-	-			-	211,203	(8,737)	(537,844)	(8,737)	(546,581)
Special Purpose Charge Assessment Variance Account		1521	(158,872)	20,486	-	-	158,872	(19,319)	(1,167)	-	-	-	-	-
Group 2 Subtotal - including 1521			2,524,994	82,599	0	0	158,872	-19,319	34,551	-741,884	-37,753	1,941,982	60,078	2,002,060
Total Group 1 and 2			-39,551,665	-813,684	39,176,243	930,150	158,872	-19,319	-8,085	-741,884	-37,753	-958,434	51,310	-907,124
The following is not included in the total claim but are included on a memo basis:														
Deferred PILs Contra Account	(2)	1563												
Board-Approved CDM Variance Account		1567												
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Contra Account		1592	749,047	-	-	-			-	(749,047)		-	-	-
Disposition and Recovery of Regulatory Balances (2011)		1595	-	-	-	-			-	-		-	-	-
Disposition and Recovery of Regulatory Balances (2009)		1595	(2,421,994)	106,515	-	-			-	-		-	-	-

Note 1 - Refer to Exhibit 9 Tab 2 for the disposition of smart meter balances.
Note 2 - Enersource applied for disposition of Account 1562 in its 2012 IRM; EB-2011-0100.

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April 5, 2012

CERTIFICATION

I hereby certify that the information filed within this application is consistent with the Board's accounting requirements and procedures in the Board's *Accounting Procedures Handbook for Electric Distribution Utilities,* revised July 31, 2007, and any other accounting procedures the Board may approve from time to time.

Dan Pastoric, Executive Vice-President and Chief Operating Officer
Enersource Hydro Mississauga Inc.

PROPOSED RATE RIDERS FOR 2013 TEST YEAR (000's)
PERIOD: REFUNDABLE / RECOVERABLE OVER 1 YEAR
EFFECTIVE DATE - JANUARY 1, 2013

	Group 1 & 2 Account Balance (Excluding GA)	Group 1 RSVA GA Account Balance (Non-RPP)	2013 Test Year kWh	2013 Test Year kW	2013 Test Year kWh (Non-RPP)	2013 Test Year kW (Non-RPP)	Group 1 & 2 - Applicable to All Customers $/kWh or $/kW	Group 1 RSVA GA Account Recovery Rate Rider Non-RPP $/kWh or $/kW	Low Voltage Service Charge $/kWh or $/kW	Rate Rider Stranded $/month	Smart Meter Disposition Rate Rider $/month
	$ (16,217,496)	**$ 2,104,764**									
Residential	$ (5,047,850)	$ 75,249	1,423,857,475		163,609,248		$ (0.0035)	$ 0.0005	$ 0.0002	$ 3.23	$ 0.13
General Service < 50 kW	$ (1,991,243)	$ 45,518	612,188,101		86,740,085		$ (0.0033)	$ 0.0005	$ 0.0002	$ 3.40	$ 0.13
Unmetered Scattered Load	$ (59,114)	$ 168	10,383,027		456,965		$ (0.0057)	$ 0.0004	$ 0.0002	$ -	$ -
General Service 50 kW - 499 kW	$ (4,403,811)	$ 720,552		6,142,022		5,278,305	$ (0.7170)	$ 0.1365	$ 0.0805	$ 1.22	$ 0.13
General Service 500 kW - 4999 kW	$ (3,286,887)	$ 839,978		5,154,338		4,826,495	$ (0.6377)	$ 0.1740	$ 0.0788	-	$ -
Large Use (> 5000 kW)	$ (1,337,922)	$ 406,775		1,737,267		1,763,697	$ (0.7701)	$ 0.2306	$ 0.0841	-	$ -
Street Lighting	$ (90,670)	$ 16,524		49,889		116,222	$ (1.8174)	$ 0.1422	$ 0.0582	-	$ -
Total	**$ (16,217,496)**	**$ 2,104,764**	**2,046,428,602**	**13,083,516**	**250,806,298**	**11,984,719**					

Rate Rider Allocation

	USoA Code	Allocator	Balance for Disposition	Residential	GS < 50 KW	Unmetered Scattered Load	GS 50-499 KW	GS 500-4999 KW	Large Users	Street Lighting	Total
Group 1 Accounts											
LV Variance Account	1550	kWh	$ 1,521,115	$ 315,940	$ 129,973	$ 2,149	$ 425,374	$ 432,644	$ 207,087	$ 7,946	$ 1,521,115
RSVA - Wholesale Market Service Charge	1580	kWh	$ (7,959,846)	$ (1,653,285)	$ (680,138)	$ (11,246)	$ (2,225,943)	$ (2,263,984)	$ (1,083,668)	$ (41,583)	$ (7,959,846)
RSVA - Wholesale Market Service Charge One Time	1582	kWh	$ 29,193	$ 6,063	$ 2,494	$ 41	$ 8,164	$ 8,303	$ 3,974	$ 153	$ 29,193
RSVA - Retail Transmission Network Charge	1584	kWh	$ 509,870	$ 105,902	$ 43,566	$ 720	$ 142,583	$ 145,020	$ 69,415	$ 2,664	$ 509,870
RSVA - Retail Transmission Connection Charge	1586	kWh	$ 461,299	$ 95,813	$ 39,416	$ 652	$ 129,001	$ 131,205	$ 62,802	$ 2,410	$ 461,299
RSVA - Power (excluding Global Adjustment)	1588	kWh	$ 423,353	$ 87,932	$ 36,174	$ 598	$ 118,389	$ 120,412	$ 57,636	$ 2,212	$ 423,353
Disposition and Recovery of Regulatory Balances (2008)	1595	1595 Share Proportion (2008)	$ 1,068	$ 331	$ 153	$ 7	$ 335	$ 170	$ 66	$ 6	$ 1,068
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	Dx Revenue	$ 1,588,873	$ 598,412	$ 215,471	$ 8,020	$ 403,528	$ 249,409	$ 87,774	$ 26,259	$ 1,588,873
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	Dx Revenue	$ 45,695	$ 17,210	$ 6,197	$ 231	$ 11,605	$ 7,173	$ 2,524	$ 755	$ 45,695
Retail Cost Variance Account - Retail	1518	# of Customers	$ 311,680	$ 218,289	$ 21,643	$ 3,712	$ 5,103	$ 602	$ 14	$ 62,318	$ 311,680
Retail Cost Variance Account - STR	1548	# of Customers	$ 346,305	$ 242,539	$ 24,047	$ 4,124	$ 5,669	$ 669	$ 15	$ 69,242	$ 346,305
Extra-Ordinary Costs (PCBs)	1572	Dx Revenue	$ 1,254,264	$ 472,390	$ 170,094	$ 6,331	$ 318,547	$ 196,884	$ 69,289	$ 20,729	$ 1,254,264
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	Dx Revenue	$ (998,177)	$ (375,940)	$ (135,365)	$ (5,038)	$ (253,508)	$ (156,686)	$ (55,142)	$ (16,497)	$ (998,177)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	Dx Revenue	$ (546,581)	$ (205,857)	$ (74,123)	$ (2,759)	$ (138,816)	$ (85,798)	$ (30,195)	$ (9,033)	$ (546,581)
Deferred IFRS Adjustment	N/A	Dx Revenue	$ (13,825,115)	$ (5,206,911)	$ (1,874,858)	$ (69,782)	$ (3,511,180)	$ (2,170,156)	$ (763,739)	$ (228,489)	$ (13,825,115)
OCI IFRS Post-Employment Adjustment	N/A	Dx Revenue	$ 619,508	$ 233,323.41	$ 84,013.03	$ 3,126.97	$ 157,337.13	$ 97,245.40	$ 34,223.39	$ 10,238.67	$ 619,508
Sub-total - Group 1 & 2 Accounts Rate Rider #1			$ (16,217,496)	$ (5,047,850)	$ (1,991,243)	$ (59,114)	$ (4,403,811)	$ (3,286,887)	$ (1,337,922)	$ (90,670)	$ (16,217,496)
RSVA - Power - Sub-Account - Global Adjustment	1588	kWh nonRPP	$ 2,104,764	$ 75,249	$ 45,518	$ 168	$ 720,552	$ 839,978	$ 406,775	$ 16,524	$ 2,104,764
Sub-total - RSVA GA (Non-RPP) Rate Rider #2			$ 2,104,764	$ 75,249	$ 45,518	$ 168	$ 720,552	$ 839,978	$ 406,775	$ 16,524	$ 2,104,764
Total to be Refunded/Recovered over one year	**Total to be Refunded / Recovered over one year**		**$ (14,112,732)**	**$ (4,972,601)**	**$ (1,945,725)**	**$ (58,945)**	**$ (3,683,259)**	**$ (2,446,909)**	**$ (931,147)**	**$ (74,146)**	**$ (14,112,732)**

Rate Rider Allocator Worksheet

		Allocation to Customer Classes %	Allocation to Customer Classes %	Allocation to Customer Classes %	Allocation to Customer Classes %	Allocation to Customer Classes %
		Total for customer class as % of Total for all classes (2011 Metered Billed kWh)	Basis for Allocation: Global Adjustment (2011 Non-RPP kWh)	Basis for Allocation: Stranded Costs (2011 Average Customers)	Basis for Allocation: Other Group 2 Accounts (2011 Distribution	Basis for Allocation: 1595 Share Recovery 2008
Residential		1,583,986,482	187,958,349	172,471	40,969,478	- 2,174,001
General Service < 50 kW		651,629,906	113,696,007	17,100	14,751,926	- 1,006,077
Unmetered Scattered Load		10,774,558	420,453	2,933	549,068	- 48,828
General Service 50 kW - 499 kW		2,132,641,331	1,799,816,500	4,032	27,626,975	- 2,202,429
General Service 500 kW - 4999 kW		2,169,087,426	2,098,120,087	476	17,075,411	- 1,116,322
Large Use (> 5000 kW)		1,038,245,079	1,016,054,213	11	6,009,317	- 436,734
Street Lighting		39,839,581	41,273,933	49,238	1,797,817	- 36,739
TOTALS		**7,626,204,363**	**5,257,339,543**	**246,260**	**108,779,993**	**- 7,021,130**

Residential		20.77%	3.58%	70.04%	37.66%	30.96%
General Service < 50 kW		8.54%	2.16%	6.94%	13.56%	14.33%
Unmetered Scattered Load		0.14%	0.01%	1.19%	0.50%	0.70%
General Service 50 kW - 499 kW		27.96%	34.23%	1.64%	25.40%	31.37%
General Service 500 kW - 4999 kW		28.44%	39.91%	0.19%	15.70%	15.90%
Large Use (> 5000 kW)		13.61%	19.33%	0.00%	5.52%	6.22%
Street Lighting		0.52%	0.79%	19.99%	1.65%	0.52%
TOTALS		**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Allocation Methodology	**Allocator**	**Residential**	**General Service < 50 kW**	**Unmetered Scattered Load**	**General Service 50 kW - 499 kW**	**General Service 500 kW - 4999 kW**	**Large Use (> 5000 kW)**	**Street Lighting**	**Total**
Basis for Allocation: 2011 Metered kWh	kWh	20.77%	8.54%	0.14%	27.96%	28.44%	13.61%	0.52%	100.00%
Basis for Allocation: Global Adjustment (2011 Non-RPP kWh)	kWh Non RPP	3.58%	2.16%	0.01%	34.23%	39.91%	19.33%	0.79%	100.00%
Basis for Allocation: Stranded Costs (2011 Average Customers)	Customer Numbers	70.04%	6.94%	1.19%	1.64%	0.19%	0.00%	19.99%	100.00%
Basis for Allocation: Other Group 2 Accounts (2011 Distribution Revenue)	Distribution Revenue	37.66%	13.56%	0.50%	25.40%	15.70%	5.52%	1.65%	100.00%
Basis for Allocation: 1595 Share Recovery 2008	1595 Share Recovery 2008	30.96%	14.33%	0.70%	31.37%	15.90%	6.22%	0.52%	100.00%

Low Voltage Charge

	A	B	C	D	E	F
	2013 Retail Transmission Connection Rate ($) kWh/kW	**2013 Charge Determinant (kWh or kW)**	**A * B Basis for Allocation**	**Allocation %**	**Allocation**	**Rate / $kWh or $kW**
RESIDENTIAL	0.0057	1,423,857,475	$ 8,115,988	21.47%	$ 322,091	$ 0.0002
General Service < 50 kW	0.0052	612,188,101	$ 3,183,378	8.42%	$ 126,336	$ 0.0002
Unmetered Scattered Load	0.0052	10,383,027	$ 53,992	0.14%	$ 2,143	$ 0.0002
General Service 50 kW - 499 kW	2.0283	6,142,022	$ 12,457,863	32.96%	$ 494,403	$ 0.0805
General Service 500 kW - 4999 kW	1.9847	5,154,338	$ 10,229,815	27.07%	$ 405,981	$ 0.0788
Large Use (> 5000 kW)	2.1197	1,737,267	$ 3,682,484	9.74%	$ 146,143	$ 0.0841
Street Lighting	1.4666	49,889	$ 73,167	0.19%	$ 2,904	$ 0.0582
TOTAL			$ 37,796,687	100.00%	$ 1,500,000	

Appendix 2-T
Deferred PILs Account 1592 Balances

The following table should be completed based on the information requested below, in accordance with the notes following the table. An explanation should be provided for any blank entries.

Tax Item	Principal as of December 31, 2011
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007 **Enersource: The item was cleared in EB-2007-0706.**	n/a
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562 **Enersource: The item was recorded in PILs account 1562.**	n/a
Ontario Capital Tax rate decrease and increase in capital deduction for 2007 **Enersource: Refer to Note (7).**	-$ 352,994
Ontario Capital Tax rate decrease and increase in capital deduction for 2008 **Enersource: Refer to Note (8).**	-$ 133,828
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	n/a
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	n/a
Capital Cost Allowance class changes from 2006 EDR application for 2006	n/a
Capital Cost Allowance class changes from 2006 EDR application for 2007	n/a
Capital Cost Allowance class changes from 2006 EDR application for 2008	n/a
Capital Cost Allowance class changes from 2006 EDR application for 2009	n/a
Capital Cost Allowance class changes from 2006 EDR application for 2010	n/a
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.	n/a
Income tax rate decrease from 36.12% to 33.5% for 2008 **Enersource: Refer to Note (9)**	-$ 416,599
Income tax rate decrease from 33.5% to 33% from 2008 COS application for 2009 **Enersource: Refer to Note (10)**	-$ 24,235
Total	-$ 927,656

Notes:

(1) Revise the deferral and variance account continuity schedule to include account 1592 as a group 2 account and enter all relevant information for transactions, adjustments, etc., for all relevant years.

Response: Enersource has consistently treated account 1592 as a group 2 account since its inception, as such no changes to the deferral and variance account continuity are required.

(2) Describe each type of tax item that has been recorded in account 1592.

Response: Refer to Notes (7) to (11)

(3) Provide the calculations that show how each item was determined and provide any pertinent supporting evidence and documentation.

Response: Refer to Notes (7) to (11)

(4) Please state whether or not the applicant followed the guidance provided in the FAQ of July 2007. If not, please provide an explanation.

Response: Enersource has followed the guidance provided in the FAQ of July 2007.

(5) Identify the account balance as of December 31, 2011 as per the 2011 Audited Financial Statements. Identify the account balance as of December 31, 2011 as per the April 2012 2.1.7 RRR filing to the Board. Provide a reconciliation if the balances provided are not identical to each other and to the total shown on the continuity schedule.

Response: The account balance as of December 31, 2011 as per the 2011 Audit Financial Statements agrees to the balance reported in the April 2012 2.1.7 RRR filing to the Board.

Principal balance at December 31, 2011	**$**	**75,431**
Carrying charges balance at December 31, 2011	**-$**	**27,868**
Total 1592 balance at December 31, 2011	**$**	**47,563**

(6) Complete the above table based on the answers to the previous. Add rows as required to complete the analysis in an informative manner. Please provide the completed table as a working Excel spreadsheet.

Response: Completed

(7) Ontario Capital Tax rate decrease and increase in capital deduction for 2007:

Net Taxable Capital per 2006 EDR Capital Model	$	470,658,648
Decrease in Ontario capital tax rate (0.300% - 0.225%)		0.075%
Credit entry to 1592 PILs variance account (not grossed-up) for the year	$	352,994

(8) Ontario Capital Tax rate decrease and increase in capital deduction for 2008:

Net Taxable Capital per 2006 EDR Capital Model		$	470,658,648
Decrease in Ontario capital tax rate (0.300% - 0.225%)			0.075%
Capital tax variance for 12 months		$	352,994
Divided by 12 months			12
Capital tax variance per month	**[A]**	$	29,416
Capital tax variance from 1/1/2008 to 4/30/2008	**[A] * 4**	-$	117,665
Amount recorded in 1592 based on billed/unbilled amounts		-$	133,828

(9) Income tax rate decrease from 36.12% to 33.5% for 2008:

	Before Change		After Change	
Regulatory taxable income per 2006 EDR Model	$	20,263,997	$	20,263,997
Corporate Income Tax Rate		36.12%		33.50%
Income tax variance for 12 months	$	7,319,356	$	6,788,439
Income tax (grossed-up) for 12 months	$	11,457,977	$	10,208,179
Income tax (grossed-up) variance for 12 months			-$	1,249,798
Divided by 12 months				12
Income tax (grossed-up) variance per month		**[B]**	-$	104,150
Amount recorded in 1592 from 1/1/2008 to 4/30/2008		**[B] * 4**	-$	416,599

(10) Income tax rate decrease from 33.5% to 33% from 2008 COS application for 2009:

	Before Change		After Change	
Regulatory taxable income per 2008 COS	$	12,750,000	$	12,750,000
Corporate Income Tax Rate		33.50%		33.00%
Income tax variance for 12 months	$	4,271,250	$	4,207,500
Income tax (grossed-up) for 12 months	$	6,422,932	$	6,279,851
Income tax (grossed-up) variance for 12 months		**[C]**	-$	143,082

	Before Change		After Change	
Computer Equipment (Class 45)				
Opening UCC Balance - Jan 1, 2007	$	908,875	$	908,875
UCC Purchases / Additions to March 18, 2007		433,806		433,806
UCC Purchases / Additions on or after March 19, 2007		1,302,281		-
Closinging UCC Balance - Dec 31, 2007		2,644,962		1,342,681
UCC Purchases / Additions in Test Year 2008		1,545,000		-
UCC Before 1/2 Yr Adjustment		4,189,962		1,342,681
1/2 Year Rule {1/2 Additions Less Disposals}		(772,500)		-
Reduced UCC		3,417,462		1,342,681
CCA Rate		45%		45%
Total CCA Test Year - Computer Equipment (Class 45)		1,537,858		604,206

Computer Equipment (Class 50)	
UCC Purchases / Additions on or after March 19, 2007	1,302,281
Closinging UCC Balance - Dec 31, 2007	1,302,281
UCC Purchases / Additions in Test Year 2008	1,545,000
UCC Before 1/2 Yr Adjustment	2,847,281
1/2 Year Rule {1/2 Additions Less Disposals}	(772,500)
Reduced UCC	2,074,781
CCA Rate	55%

CCA Test Year			1,141,130
Total CCA Test Year - Computer Equipment	$ 1,537,858		$ 1,745,336
Difference in CCA			$ 207,478
Difference in corporate income tax rate from 2008 to 2009 (33.5% - 33%)			33.5%
Tax impact			69,505
Income tax (grossed-up) for 12 months (2008)		**[D]**	$ 104,519
Difference in CCA			$ 207,478
Corporate income tax rate (2009)			33.0%
Tax impact			68,468

Smart Meters

Introduction

Enersource supports the province's Smart Metering Initiative ("SMI") through its Residential Smart Meter Deployment Program and Small General Service Smart Meter Deployment Program (collectively referred to as Enersource's "Smart Metering Integration Plan" or "SMIP"). At December 31, 2010, Enersource had completed mandated smart meter installations, including newly constructed premises, for over 99% of its residential customers and 85% of its general service less than 50 kW ("GS<50 kW") customers. This combined total represents 98% of Enersource's customers mandated to receive smart meters.

By December 31, 2011 Enersource had installed smart meters for virtually all residential and GS<50 kW customers with the exception of a small number of customers who have refused installation of a smart meter ("customer refusals"), installation-related technical issues, hazardous meter bases, and 600 volt ("600 V") small general service ("GS") accounts. Enersource continues its efforts to install smart meters at these locations.

OEB Approvals to Date

Enersource incurred costs for smart meter activities from January 1, 2006 to April 30, 2007, that were reviewed and approved in a combined hearing in proceeding EB-2007-0063 (the "Combined Smart Meter Proceeding"). The Board's decision was released on August 8, 2007.

Enersource also applied for OEB approval and recovery of costs incurred in relation to smart meters deployed between May 1 and December 31, 2007, which costs included capital investments for smart meters installed during that

period, and associated operating expenses (EB-2008-0265). The Board's decision stated[1]:

> Insofar as these costs relate to the implementation of a firm and unequivocal policy of the government, the Board also finds that they were prudently incurred.
>
> The Board notes that the meters were procured under the same agreement as was reviewed in the Combined Smart Meter Proceeding. The Board also notes that the costs per installed meter over this period are consistent with the per meter costs previously reviewed and approved by the Board in that Proceeding. The Board therefore approves those costs. The Board also approves the accounting changes as proposed by Enersource in the Application to recognize these approved smart meter costs and those approved in the Combined Smart Meter Proceeding in rate base, and to dispose of the related amounts in the established variance accounts.

Smart Metering Integration Plan Post-2007

Enersource replaced 106,065 residential, and 17,357 small GS conventional meters with smart meters[2], and installed 341 collectors between January 1, 2008 and December 31, 2011. The revenue requirement related to these meters, with a capital cost of $27,302 from 2008 to 2011, comprises the SMIP, with the exception of the forecasted meters for 2012.

By December 31, 2011, Enersource had installed 191,300 smart meters (which includes 7,342 individual metered suites typically installed in condominium

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[1] EB-2008-0265 Decision dated December 8, 2008, p. 4.

[2] Small general service refers to all customers GS<50 kW and approximately 1,400 general service greater than 50 kW ("GS>50 kW") customers. Due to the communal meter room design of a few buildings, Enersource replaced the mechanical meters with smart meters for this small group of GS>50 kW demand customers who would benefit from wireless smart meter network meter reading.

buildings) amounting to substantially all (99.3%) of its residential customers mandated to receive smart meters.

Due to delays in availability of Measurement Canada-approved 600 V smart meters, Enersource was unable to complete the planned installations for the GS<50 kW class of customers mandated to receive smart meters. At December 31, 2011, Enersource had completed smart meter installations for 89.1% of GS<50 kW customers. It is expected the remaining 600 V meters will be completed by the end of the second quarter 2012.

Outstanding Smart Meter Replacements

As mentioned above, there remains a small number of situations where Enersource has attempted but been unable to install a smart meter due to customer refusals, lack of cooperation, or other installation challenges.

Enersource is trying to address the concerns of the customer refusals, and to overcome the other installation challenges. While Enersource expects to complete many of the smart meter replacements for these remaining customers by the end of the second quarter in 2012, it may take considerable additional time and effort to achieve 100% compliance.

Enersource forecasts a further 924 residential and 1,680 GS<50 kW smart meters to be changed in 2012. The capital costs of these meters and the final systems implementation is $1,488, and the OM&A costs are $635.

In Table 1 below is the number of mechanical meters remaining (or alternatively, the number of smart meters pending installation) within the residential class, and the constraints encountered.

Table 1: Remaining Residential Mechanical Meters at December 31, 2011

Constraint Encountered	Number of Mechanical Meters Remaining	Percentage of the total Remaining
Customer Refusals	116	12%
Obstruction	263	29%
No Access	325	35%
Hazardous	220	24%
Total	**924**	**100%**

In Table 2 below is the number of mechanical meters remaining within the GS<50 kW class, and the constraints encountered.

Table 2: Remaining GS<50 kW Mechanical Meters at December 31, 2011

Constraint Encountered	Number of Mechanical Meters Remaining	Percentage of the total Remaining
Lack of Availability of 600V Smart Meters for Replacement	1,504	89.52%
No Access	176	10.48%
Total	**1680**	**100%**

Demand Customers

In communal meter rooms of certain buildings (such as retail plazas), where the large majority of customers are GS<50 kW not requiring demand readings, but include a small minority of GS meters requiring demand readings (GS>50 kW), Enersource took advantage of the smart meter communication network to reduce future meter reading costs by installing smart meters for those demand customers. This equates to 1,410 meters installed for GS demand customers, i.e., GS>50 kW, as of December 31, 2011.

Expenditures for Smart Meters

In Table 3 below are Enersource's actual smart meter capital and operating costs to December 31, 2011.[3]

Table 3: Capital and Operating Costs to December 31, 2012 ($000s)

Capital and Operating Costs to December 31, 2012 ($000s)				
Customer Class or Category of Cost	**2006-2007 Capital**	**2006-2007 Operating**	**2008-2012 Capital**	**2008-2012 Operating**
Residential	7,833	322	14,441	500
GS<50 kW	0	0	8,754	75
GS>50 kW	0	0	759	6
Condominiums (Retrofit)	0	0	-153	13
Software	139	0	646	0
MDM/R Integration	0	0	1,808	0
Hazardous Meter Bases	0	0	1,046	1,471
Total	7,972	322	27,302	2,065

Table 4 below provides a summary of the capital costs, and a calculation of the average installed cost per meter, which includes both the cost of the meter and its installation. The full capital cost includes other capital costs, i.e., mainly communication devices, computers and software used in the Advanced Metering Infrastructure ("AMI") that allows communication with the meters and programming changes to the customer billing systems.

[3] Actual costs to December 31, 2011 and forecasted costs for 2012. Note that all costs for 2006-2007 have been deemed prudent by the Board, and as a result have already been recovered.

Table 4: Summary of Smart Meter Capital Costs

	Residential	GS<50 kW	GS>50 kW	Total
Number of Installed Meters:				
Installed Meters 2006/07	60,536	0	0	60,536
Installed Meters from 2008 (Actual) to 2012 (Forecasted)	106,989	17,627	1,410	126,026
Forecasted Installed at May 31, 2012	167,525	17,627	1,410	186,562
Capital Costs ($000s):				
Capital Costs 2006/07	$ 7,972	$ -	$ -	$ 7,972
Capital Costs 2008 (Actual) to 2012 (Forecasted)	$ 17,698	$ 8,838	$ 766	$ 27,302
Forecasted Capital Costs 2012	$ 25,670	$ 8,838	$ 766	$ 35,274
Capital Costs Per Meter ($ per meter):				
Capital Cost Per Meter 2006/07	$ 131.69	$ -	$ -	$ 131.69
Capital Cost Per Meter 2008 to 2012	$ 165.42	$ 501.39	$ 543.26	$ 216.64
Capital Cost Per Meter Forecasted 2012	$ 153.23	$ 501.39	$ 543.26	$ 189.07

Enersource's average capital cost per meter of $189.07[4] is reasonable compared to the sector average capital cost of $186.76 derived from the OEB's *"Sector Smart Meter Audit Review Report"*[5]. As this reported sector average capital cost is based on meters installed up to September 30, 2009 and does not include all of the more expensive GS meters, it is expected the sector average unit cost will increase with the inclusion of those meters. Enersource's average capital cost per meter includes these more expensive meters.

Other capital is comprised of the components of the AMI, AMI computer equipment and software, as well as program management services.

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[4] The value of $189.07 is the total capital costs for all meters, divided by the total number of installed meters.

[5] OEB Regulatory Audit and Accounting, dated March 31, 2010, p. 6. Based on 3,053,931 meters with a capital cost of $570,339,200 as at September 30, 2009.

No amounts have been included in actual or projected costs for charges for use of the provincial MDM/R. However, Enersource anticipates being permitted to recover those costs at a later date, upon completion of the Board's proceeding, EB-2012-0100[6].

Customer Communications Costs

The main component of the customer communication costs is related to open house events, materials and mailings to inform customers about Enersource's SMIP and TOU pricing. Enersource provided broad-based communications (via bill inserts, separate delivery of informational materials, attended information booths in local community centres, etc.) to ensure customers were aware of the impacts of the SMIP and to advise them of steps that could be taken to manage their consumption under TOU rates. Additional customer communication costs will be incurred as the TOU rollout continues to May, 2012.

Meter Data Management and Repository

In August, 2011, Enersource successfully completed its system integration with the provincial MDM/R and started transitioning customers onto TOU billing. The conversion process is extremely complex, directly impacts each customer, and impacts the majority of the conventional meter-to-cash processes. TOU introduced significant change for customers and Enersource divisions charged with supporting the meter-to-cash and customer care functions. Enersource's meter-to-cash process now relies on synchronization with the MDM/R, and handling and resolving exceptions reported by the MDM/R, including verifying information sent to and provided from the MDM/R. In addition, the meter-to-cash

[6] Application by the Independent Electricity System Operator as the SME, for Approval of a Smart Metering Charge and the Smart Metering Agreement for Distributors, in order to recover past and ongoing costs of the provincial MDM/R, dated March 23, 2012.

process relies on ensuring the accuracy and timeliness of the daily collection of over five million meter readings and to manage effective interactions between internal systems i.e., the AMI and Customer Care and Billing (CC&B), and the external system i.e., the MDM/R. As such, additional resources and effort have been assigned to manage this change, and operate and maintain new systems and business processes as a result of TOU.

As of the end of March, 2012, 99.1% of smart meters have been installed, including new premises. Of the 166,964 smart meters, 87.8% are registered with the MDM/R and 108,234 customers, or 61.9% of customers with smart meters, are being billed TOU rates. By the end of May, 2012 Enersource will have completed the SMIP and account conversion onto TOU rates.

Budgeted 2012 Costs

Ongoing costs in 2012 are attributable to interfacing with the MDM/R for the implementation of TOU rates, development and enhancement of the various applications and processes at Enersource to manage and process the TOU data, and replacement of the remaining residential and GS<50 kW 600 V meters with smart meters.

As indicated above, Enersource is trying to address customer refusals and other installation challenges. Enersource is also assessing the situations where standard smart meter installations are not possible and is working to resolve these issues.

Enersource estimates that it will spend an additional $1,488 in capital costs in 2012 on installation of the remaining smart meters.

Table 5 below provides the number of smart meters installed, by year of installation and by type of customer.

Table 5: Installation of Smart Meters by Year and by Customer Class (numbers of meters)

	2006/07	2008	2009	2010	2011	Forecast 2012	Total
Residential	60,536	44,541	33,610	19,792	8,122	924	167,525
GS<50 kW	0	1,763	342	6,507	7,335	~1,680[7]	17,627
GS>50kW	0	0	705	802	-97[8]	0	1,410
Total	60,536	46,304	34,657	27,101	15,360	2,604	186,562

By the end of May, 2012 Enersource expects to have completed the installation of smart meters for 167,525 residential customers, 17,627 GS<50 kW and 1,410 GS>50 kW (demand customers), to complete almost 100% of the customers mandated to receive smart meters, not including newly constructed premises.

Recovery Being Sought

Pursuant to G-2011-0001 Guideline Smart Meter Funding and Cost Recovery – Final Disposition[9], Enersource is seeking approval of the smart meter costs shown below, and authorization to transfer the approved amounts from the smart meter deferral accounts to the appropriate fixed asset, revenue, and expense accounts. Enersource has used the 2013 Smart Meter Model provided by the

[7] Includes 1,500 600 V smart meters.

[8] There was a discrepancy in Enersource's CC&B report code that caused a higher than actual number of meters to be reported to the OEB as installed in 2010. The adjustment appears in 2011.

[9] *OEB G-2011-0001 Guideline Smart Meter Funding and Cost Recovery – Final Disposition*, dated December 15, 2011.

Board (found at Exhibit 9 Tab 2 Schedule 1 Appendix 1) to calculate the Smart Meter Disposition Rider.

Table 7: Recovery of Smart Meter Costs ($000s)

		2006 - 2012 [1]
Smart Meter Revenue Requirement		$ 19,975
Interest on operating and depreciation expenses		356
		$ 20,331
Smart Meter Funding Adder		(19,235)
Interest on Smart Meter Funding Adder		(797)
Net Deferred Revenue Requirement to be Recovered		**$ 299**
Number of Metered Customers (2013 average) [2]		198,639
Proposed Smart Meter Disposition Rate Rider	$/month	0.13

Note:
[1] All amounts include forecasted amounts for 2012.
[2] Includes Residential, GS < 50 KW and GS 50-499 KW

The net difference is a recovery of $299, the amount between the revenue requirement related to the smart meter costs, and the corresponding smart meter funding adders collected from May 1, 2006 to December 31, 2012[10]. Enersource proposes to recover this amount from customers by a monthly rate rider of $0.13 per customer over a twelve-month period starting January 1, 2013. Based on the guidance provided in the 2013 Smart Meter Model, this rate rider would only

[10] The Smart Meter Model calculates the difference between the revenue requirement from 2006 to 2012 and the collected amounts via the Smart Meter Funding Adders during those same years.

apply to residential, GS<50 kW, and GS 50 – 499 kW customers, as only these classes received smart meters as part of the deployment program.

Enersource has completed Appendix 2-Q to this exhibit.

V 2.21

Ontario Energy Board

Smart Meter Model (for 2013 Rates Applications)

E.L.K. Energy Inc.
Enersource Hydro Mississauga Inc.

Choose Your Utility:

Application Contact Information

Name:	Martin Sultana
Title:	Manager, Rates
Phone Number:	905-283-4255
Email Address:	msultana@enersource.com
We are applying for rates effective:	January 1, 2013
Last COS Re-based Year	2008

Legend

- DROP-DOWN MENU
- INPUT FIELD
- CALCULATION FIELD

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While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. 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 review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2012, distributors that have completed their deployments by the end of 2011 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2012, distributors should enter the forecasted OM&A for 2012 for all smart meters in service.

	2006	2007	2008	2009	2010	2011	2012	2013	Total
Smart Meter Capital Cost and Operational Expense Data	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
Smart Meter Installation Plan									
Actual/Planned number of Smart Meters installed during the Calendar Year									
Residential	506	60,030	44,541	33,610	19,792	8,122	924		167525
General Service < 50 kW			1,763	342	6,507	7,335	1,680		17627
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)	506	60030	46304	33952	26299	15457	2604	0	182548
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed	0.28%	33.16%	58.53%	77.13%	91.53%	100.00%	0.00%	101.15%	100.00%
Actual/Planned number of GS > 50 kW meters installed				705	802	-97			1410
Other (please identify)									0
Total Number of Smart Meters installed or planned to be installed	506	60030	46304	34657	27101	15360	2604	0	186562

1 Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	**Asset Type** (Asset type must be selected to enable calculations)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter	126,242	7,088,035	4,526,634	6,257,479	6,091,712	1,285,530	875,000		$ 26,250,632
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter		77,586	533,387	584,813	609,081	520,439			$ 2,325,306
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*	Smart Meter				1,820					$ 1,820
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*	Applications Software					22,237				$ 22,237
Total Advanced Metering Communications Devices (AMCD)		$ 126,242	$ 7,165,621	$ 5,060,021	$ 6,844,112	$ 6,723,030	$ 1,805,969	$ 875,000	$ -	$ 28,599,995

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.2.1 Collectors	Smart Meter		348,831	184,333	67,195	15,365	1,329			$ 617,053
1.2.2 Repeaters *(may include radio licence, etc.)*										$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*	Smart Meter			27,650	10,079	4,954	1,336			$ 44,019
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ 348,831	$ 211,983	$ 77,274	$ 20,319	$ 2,665	$ -	$ -	$ 661,072

1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.3.1 Computer Hardware	Computer Hardware	38,163	153,822	602,685	103,977					$ 898,647
1.3.2 Computer Software	Applications Software	47,268	92,184	-139,452		43,075	2,172,192	613,078		$ 2,828,345
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*										$ -
Total Advanced Metering Control Computer (AMCC)		$ 85,431	$ 246,006	$ 463,233	$ 103,977	$ 43,075	$ 2,172,192	$ 613,078	$ -	$ 3,726,992

1.4 WIDE AREA NETWORK (WAN)	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.4.1 Activiation Fees										$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*										$ -
1.5.2 AMI Interface to CIS										$ -
1.5.3 Professional Fees	Applications Software				768,078					$ 768,078
1.5.4 Integration	Smart Meter									$ -
1.5.5 Program Management	Smart Meter			323,503	580,793	495,802	155,048			$ 1,555,146
1.5.6 Other AMI Capital										$ -
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ -	$ 323,503	$ 1,348,871	$ 495,802	$ 155,048	$ -	$ -	$ 2,323,224
Total Capital Costs Related to Minimum Functionality		$ 211,673	$ 7,760,458	$ 6,058,740	$ 8,374,234	$ 7,282,226	$ 4,135,874	$ 1,488,078	$ -	$ 35,311,283

1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Asset Type	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06										$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service										$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.										$ -
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter Capital Costs		$ 211,673	$ 7,760,458	$ 6,058,740	$ 8,374,234	$ 7,282,226	$ 4,135,874	$ 1,488,078	$ -	$ 35,311,283

2 OM&A Expenses

2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	Forecast	
2.1.1 Maintenance *(may include meter reverification costs, etc.)*	26,603	6,855							$ 33,458
2.1.2 Other *(please specifiy)*									$ -
Total Incremental AMCD OM&A Costs	$ 26,603	$ 6,855	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,458
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)									
2.2.1 Maintenance									$ -
2.2.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)									
2.3.1 Hardware Maintenance *(may include server support, etc.)*									$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*		3,917	47,888	53,445	3,089	156,273	130,000		$ 394,612
2.3.2 Other *(please specifiy)*									$ -
Total Incremental AMCC OM&A Costs	$ -	$ 3,917	$ 47,888	$ 53,445	$ 3,089	$ 156,273	$ 130,000	$ -	$ 394,612
2.4 WIDE AREA NETWORK (WAN)									
2.4.1 WAN Maintenance		1,078	38,285	35,488	56,922	64,359	147,000		$ 343,132
2.4.2 Other *(please specifiy)*									$ -
Total Incremental AMRC OM&A Costs	$ -	$ 1,078	$ 38,285	$ 35,488	$ 56,922	$ 64,359	$ 147,000	$ -	$ 343,132
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY									
2.5.1 Business Process Redesign									$ -
2.5.2 Customer Communication (may include project communication, etc.)		107,032	133,125	2,569		137,250			$ 379,976
2.5.3 Program Management		4,903							$ 4,903
2.5.4 Change Management (may include training, etc.)			300	1,830	5,407	-6,032	5,000		$ 6,505
2.5.5 Administration Costs		166,511	196,795	31,378	234,299	-55,053	301,619		$ 875,549
2.5.6 Other AMI Expenses *(please specify)*		5,591	-322,253	-457,014	617,935	454,362	51,217	180,228	$ 530,066
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ 284,037	$ 7,967	-$ 421,237	$ 857,641	$ 530,527	$ 357,836	$ 180,228	$ 1,796,999
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ 26,603	$ 295,887	$ 94,140	-$ 332,304	$ 917,652	$ 751,159	$ 634,836	$ 180,228	$ 2,568,201
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual			
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06									$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service									$ -
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.									$ -
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Smart Meter OM&A Costs	$ 26,603	$ 295,887	$ 94,140	-$ 332,304	$ 917,652	$ 751,159	$ 634,836	$ 180,228	$ 2,568,201

3 Aggregate Smart Meter Costs by Category

3.1	**Capital**									
3.1.1	Smart Meter	$ 126,242	$ 7,514,452	$ 5,595,507	$ 7,502,179	$ 7,216,914	$ 1,963,682	$ 875,000	$ -	$ 30,793,976
3.1.2	Computer Hardware	$ 38,163	$ 153,822	$ 602,685	$ 103,977	$ -	$ -	$ -	$ -	$ 898,647
3.1.3	Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ 47,268	$ 92,184	-$ 139,452	$ 768,078	$ 65,312	$ 2,172,192	$ 613,078	$ -	$ 3,618,660
3.1.7	**Total Capital Costs**	**$ 211,673**	**$ 7,760,458**	**$ 6,058,740**	**$ 8,374,234**	**$ 7,282,226**	**$ 4,135,874**	**$ 1,488,078**	**$ -**	**$ 35,311,283**
3.2	**OM&A Costs**									
3.2.1	**Total OM&A Costs**	**$ 26,603**	**$ 295,887**	**$ 94,140**	**-$ 332,304**	**$ 917,652**	**$ 751,159**	**$ 634,836**	**$ 180,228**	**$ 2,568,201**

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

	2006	2007	2008	2009	2010	2011	2012	2013
Cost of Capital								
Capital Structure[1]								
Deemed Short-term Debt Capitalization			4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	60.0%	60.0%	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Preferred Shares								
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters								
Deemed Short-term Debt Rate			4.47%	4.47%	4.47%	4.47%	4.47%	4.47%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.44%	6.44%	6.44%	6.44%	6.44%	6.44%	6.44%	6.44%
Target Return on Equity (ROE)	9.0%	9.00%	8.57%	8.57%	8.57%	8.57%	8.57%	8.57%
Return on Preferred Shares								
WACC	7.46%	7.46%	7.21%	7.21%	7.21%	7.21%	7.21%	7.21%
Working Capital Allowance								
Working Capital Allowance Rate	15.0%	15.0%	13.3%	13.3%	13.3%	13.3%	13.3%	13.3%
(% of the sum of Cost of Power + controllable expenses)								
Taxes/PILs								
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%	0.00%

Depreciation Rates

(expressed as expected useful life in years)

Smart Meters - years	15	15	15	15	15	15	15	15
- rate (%)	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%	6.67%
Computer Hardware - years	5	5	5	5	5	5	5	5
- rate (%)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Computer Software - years	2	2	10	10	10	5	5	5
- rate (%)	50.00%	50.00%	10.00%	10.00%	10.00%	20.00%	20.00%	20.00%
Tools & Equipment - years	10	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Other Equipment - years	10	10	10	10	10	10	10	10
- rate (%)	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

CCA Rates

Smart Meters - CCA Class	47	47	47	47	47	47	47	47
Smart Meters - CCA Rate	8%	8%	8%	8%	8%	8%	8%	8%
Computer Equipment - CCA Class	45	45	50	50	50	50	50	50
Computer Equipment - CCA Rate	45%	45%	55%	55%	55%	55%	55%	55%
General Equipment - CCA Class								
General Equipment - CCA Rate								
Applications Software - CCA Class	12	12	12	12	12	12	12	12
Applications Software - CCA Rate	100%	100%	100%	100%	100%	100%	100%	100%

Assumptions

1 *Planned smart meter installations occur evenly throughout the year.*

2 *Fiscal calendar year (January 1 to December 31) used.*

3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

	2006	2007	2008	2009	2010	2011	2012	2013
Net Fixed Assets - Smart Meters								
Gross Book Value								
Opening Balance		$ 126,242	$ 7,640,694	$ 13,236,201	$ 20,738,380	$ 27,955,294	$ 29,918,976	$ 30,793,976
Capital Additions during year (from Smart Meter Costs)	$ 126,242	$ 7,514,452	$ 5,595,507	$ 7,502,179	$ 7,216,914	$ 1,963,682	$ 875,000	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ 126,242	$ 7,640,694	$ 13,236,201	$ 20,738,380	$ 27,955,294	$ 29,918,976	$ 30,793,976	$ 30,793,976
Accumulated Depreciation								
Opening Balance		-$ 4,208	-$ 263,106	-$ 949,750	-$ 2,082,229	-$ 3,705,351	-$ 5,633,689	-$ 7,645,605
Amortization expense during year	-$ 4,208	-$ 258,898	-$ 686,644	$ (1,132,479.00)	$ (1,623,121.94)	$ (1,928,337.93)	-$ 2,011,916	-$ 2,041,083
Retirements/Removals (if applicable)								
Closing Balance	-$ 4,208	-$ 263,106	-$ 949,750	-$ 2,082,229	-$ 3,705,351	-$ 5,633,689	-$ 7,645,605	-$ 9,686,688
Net Book Value								
Opening Balance	$ -	$ 122,034	$ 7,377,588	$ 12,286,451	$ 18,656,151	$ 24,249,943	$ 24,285,287	$ 23,148,371
Closing Balance	$ 122,034	$ 7,377,588	$ 12,286,451	$ 18,656,151	$ 24,249,943	$ 24,285,287	$ 23,148,371	$ 21,107,288
Average Net Book Value	$ 61,017	$ 3,749,811	$ 9,832,020	$ 15,471,301	$ 21,453,047	$ 24,267,615	$ 23,716,829	$ 22,127,830
Net Fixed Assets - Computer Hardware								
Gross Book Value								
Opening Balance		$ 38,163	$ 191,985	$ 794,670	$ 898,647	$ 898,647	$ 860,485	$ 860,485
Capital Additions during year (from Smart Meter Costs)	$ 38,163	$ 153,822	$ 602,685	$ 103,977	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)						$ 38,162		
Closing Balance	$ 38,163	$ 191,985	$ 794,670	$ 898,647	$ 898,647	$ 860,485	$ 860,485	$ 860,485
Accumulated Depreciation								
Opening Balance	$ -	-$ 3,816	-$ 26,831	-$ 237,494	-$ 383,507	-$ 540,269	-$ 654,912	-$ 784,197
Amortization expense during year	-$ 3,816	-$ 23,015	-$ 210,663	-$ 146,013	-$ 156,762	-$ 152,805	-$ 129,285	-$ 65,539
Retirements/Removals (if applicable)						-$ 38,162		
Closing Balance	-$ 3,816	-$ 26,831	-$ 237,494	-$ 383,507	-$ 540,269	-$ 654,912	-$ 784,197	-$ 849,736
Net Book Value								
Opening Balance	$ -	$ 34,347	$ 165,154	$ 557,176	$ 515,140	$ 358,378	$ 205,573	$ 76,288
Closing Balance	$ 34,347	$ 165,154	$ 557,176	$ 515,140	$ 358,378	$ 205,573	$ 76,288	$ 10,749
Average Net Book Value	$ 17,173	$ 99,750	$ 361,165	$ 536,158	$ 436,759	$ 281,975	$ 140,930	$ 43,518

Net Fixed Assets - Computer Software (including Applications Software)

Gross Book Value								
Opening Balance		$ 47,268	$ 139,452	$ -	$ 768,078	$ 833,390	$ 3,005,582	$ 3,618,660
Capital Additions during year (from Smart Meter Costs)	$ 47,268	$ 92,184	-$ 139,452	$ 768,078	$ 65,312	$ 2,172,192	$ 613,078	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ 47,268	$ 139,452	$ -	$ 768,078	$ 833,390	$ 3,005,582	$ 3,618,660	$ 3,618,660
Accumulated Depreciation								
Opening Balance	$ -	-$ 11,817	-$ 58,497	$ -	-$ 38,138	-$ 118,574	-$ 419,858	-$ 977,798
Amortization expense during year	-$ 11,817	-$ 46,680	$ 58,497	$ (38,137.90)	$ (80,436.40)	-$ 301,284	-$ 557,940	-$ 619,493
Retirements/Removals (if applicable)								
Closing Balance	-$ 11,817	-$ 58,497	$ -	-$ 38,138	-$ 118,574	-$ 419,858	-$ 977,798	-$ 1,597,291
Net Book Value								
Opening Balance	$ -	$ 35,451	$ 80,955	$ -	$ 729,940	$ 714,816	$ 2,585,724	$ 2,640,862
Closing Balance	$ 35,451	$ 80,955	$ -	$ 729,940	$ 714,816	$ 2,585,724	$ 2,640,862	$ 2,021,369
Average Net Book Value	$ 17,726	$ 58,203	$ 40,478	$ 364,970	$ 722,378	$ 1,650,270	$ 2,613,293	$ 2,331,115

Net Fixed Assets - Tools and Equipment

Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets - Other Equipment

Gross Book Value								
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value								
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

	2006	2007	2008	2009	2010	2011	2012	2013
Average Net Fixed Asset Values (from Sheet 4)								
Smart Meters	$ 61,017	$ 3,749,811	$ 9,832,020	$ 15,471,301	$ 21,453,047	$ 24,267,615	$ 23,716,829	$ 22,127,830
Computer Hardware	$ 17,173	$ 99,750	$ 361,165	$ 536,158	$ 436,759	$ 281,975	$ 140,930	$ 43,518
Computer Software	$ 17,726	$ 58,203	$ 40,478	$ 364,970	$ 722,378	$ 1,650,270	$ 2,613,293	$ 2,331,115
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ 95,916**	**$ 3,907,764**	**$ 10,233,662**	**$ 16,372,429**	**$ 22,612,184**	**$ 26,199,860**	**$ 26,471,052**	**$ 24,502,463**
Working Capital								
Operating Expenses (from Sheet 2)	$ 26,603	$ 295,887	$ 94,140	-$ 332,304	$ 917,652	$ 751,159	$ 634,836	$ 180,228
Working Capital Factor (from Sheet 3)	15%	15%	13%	13%	13%	13%	13%	13%
Working Capital Allowance	$ 3,990	$ 44,383	$ 12,521	-$ 44,196	$ 122,048	$ 99,904	$ 84,433	$ 23,970
Incremental Smart Meter Rate Base	**$ 99,906**	**$ 3,952,147**	**$ 10,246,183**	**$ 16,328,233**	**$ 22,734,232**	**$ 26,299,764**	**$ 26,555,485**	**$ 24,526,434**
Return on Rate Base								
Capital Structure								
Deemed Short Term Debt	$ -	$ -	$ 409,847	$ 653,129	$ 909,369	$ 1,051,991	$ 1,062,219	$ 981,057
Deemed Long Term Debt	$ 59,944	$ 2,371,288	$ 5,737,862	$ 9,143,810	$ 12,731,170	$ 14,727,868	$ 14,871,072	$ 13,734,803
Equity	$ 39,963	$ 1,580,859	$ 4,098,473	$ 6,531,293	$ 9,093,693	$ 10,519,906	$ 10,622,194	$ 9,810,573
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ 99,906	$ 3,952,147	$ 10,246,183	$ 16,328,233	$ 22,734,232	$ 26,299,764	$ 26,555,485	$ 24,526,434
Return on								
Deemed Short Term Debt	$ -	$ -	$ 18,320	$ 29,195	$ 40,649	$ 47,024	$ 47,481	$ 43,853
Deemed Long Term Debt	$ 3,860	$ 152,711	$ 369,518	$ 588,861	$ 819,887	$ 948,475	$ 957,697	$ 884,521
Equity	$ 3,597	$ 142,277	$ 351,239	$ 559,732	$ 779,329	$ 901,556	$ 910,322	$ 840,766
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ 7,457	$ 294,988	$ 739,078	$ 1,177,788	$ 1,639,866	$ 1,897,055	$ 1,915,500	$ 1,769,141
Operating Expenses	$ 26,603	$ 295,887	$ 94,140	-$ 332,304	$ 917,652	$ 751,159	$ 634,836	$ 180,228
Amortization Expenses (from Sheet 4)								
Smart Meters	$ 4,208	$ 258,898	$ 686,644	$ 1,132,479	$ 1,623,122	$ 1,928,338	$ 2,011,916	$ 2,041,083
Computer Hardware	$ 3,816	$ 23,015	$ 210,663	$ 146,013	$ 156,762	$ 152,805	$ 129,285	$ 65,539
Computer Software	$ 11,817	$ 46,680	-$ 58,497	$ 38,138	$ 80,436	$ 301,284	$ 557,940	$ 619,493
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ 19,841	$ 328,593	$ 838,810	$ 1,316,630	$ 1,860,320	$ 2,382,427	$ 2,699,141	$ 2,726,115
Incremental Revenue Requirement before Taxes/PILs	$ 53,901	$ 919,468	$ 1,672,028	$ 2,162,114	$ 4,417,838	$ 5,030,641	$ 5,249,477	$ 4,675,484
Calculation of Taxable Income								
Incremental Operating Expenses	$ 26,603	$ 295,887	$ 94,140	-$ 332,304	$ 917,652	$ 751,159	$ 634,836	$ 180,228
Amortization Expense	$ 19,841	$ 328,593	$ 838,810	$ 1,316,630	$ 1,860,320	$ 2,382,427	$ 2,699,141	$ 2,726,115
Interest Expense	$ 3,860	$ 152,711	$ 387,839	$ 618,056	$ 860,536	$ 995,499	$ 1,005,178	$ 928,375
Net Income for Taxes/PILs	$ 3,597	$ 142,277	$ 351,239	$ 559,732	$ 779,329	$ 901,556	$ 910,322	$ 840,766
Grossed-up Taxes/PILs (from Sheet 7)	-$ 7,245.81	$ 41,439.44	$ 76,178.68	$ 74,507.30	$ 154,693.79	$ 42,592.09	$ 87,425.29	$ -
Revenue Requirement, including Grossed-up Taxes/PILs	$ 46,656	$ 960,907	$ 1,748,206	$ 2,236,621	$ 4,572,532	$ 5,073,233	$ 5,336,903	$ 4,675,484

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ 121,192.32	$ 7,325,370.85	$ 12,111,027.91	$ 18,344,237.51	$ 23,804,935.95	$ 23,785,675.80	$ 22,722,821.73
Capital Additions	$ 126,242.00	$ 7,514,452.00	$ 5,595,507.00	$ 7,502,179.00	$ 7,216,914.00	$ 1,963,682.00	$ 875,000.00	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ 126,242.00	$ 7,635,644.32	$ 12,920,877.85	$ 19,613,206.91	$ 25,561,151.51	$ 25,768,617.95	$ 24,660,675.80	$ 22,722,821.73
Half Year Rule (1/2 Additions - Disposals)	$ 63,121.00	$ 3,757,226.00	$ 2,797,753.50	$ 3,751,089.50	$ 3,608,457.00	$ 981,841.00	$ 437,500.00	$ -
Reduced UCC	$ 63,121.00	$ 3,878,418.32	$ 10,123,124.35	$ 15,862,117.41	$ 21,952,694.51	$ 24,786,776.95	$ 24,223,175.80	$ 22,722,821.73
CCA Rate Class	47	47	47	47	47	47	47	47
CCA Rate	8%	8%	8%	8%	8%	8%	8%	8%
CCA	$ 5,049.68	$ 310,273.47	$ 809,849.95	$ 1,268,969.39	$ 1,756,215.56	$ 1,982,942.16	$ 1,937,854.06	$ 1,817,825.74
Closing UCC	$ 121,192.32	$ 7,325,370.85	$ 12,111,027.91	$ 18,344,237.51	$ 23,804,935.95	$ 23,785,675.80	$ 22,722,821.73	$ 20,904,995.99

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ 29,576.33	$ 135,479.03	$ 497,912.19	$ 299,443.81	$ 134,749.71	$ 60,637.37	$ 27,286.82
Capital Additions Computer Hardware	$ 38,163.00	$ 153,822.00	$ 602,685.00	$ 103,977.00	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ 38,163.00	$ 183,398.33	$ 738,164.03	$ 601,889.19	$ 299,443.81	$ 134,749.71	$ 60,637.37	$ 27,286.82
Half Year Rule (1/2 Additions - Disposals)	$ 19,081.50	$ 76,911.00	$ 301,342.50	$ 51,988.50	$ -	$ -	$ -	$ -
Reduced UCC	$ 19,081.50	$ 106,487.33	$ 436,821.53	$ 549,900.69	$ 299,443.81	$ 134,749.71	$ 60,637.37	$ 27,286.82
CCA Rate Class	45	45	50	50	50	50	50	50
CCA Rate	45%	45%	55%	55%	55%	55%	55%	55%
CCA	$ 8,586.68	$ 47,919.30	$ 240,251.84	$ 302,445.38	$ 164,694.10	$ 74,112.34	$ 33,350.55	$ 15,007.75
Closing UCC	$ 29,576.33	$ 135,479.03	$ 497,912.19	$ 299,443.81	$ 134,749.71	$ 60,637.37	$ 27,286.82	$ 12,279.07

UCC - General Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	0	0	0	0	0	0	0	0
CCA Rate	0%	0%	0%	0%	0%	0%	0%	0%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC - Applications Software

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
Opening UCC	$ -	$ 23,634.00	$ 46,092.00	-$ 139,452.00	$ 384,039.00	$ 32,656.00	$ 1,086,096.00	$ 306,539.00
Capital Additions Applications Software	$ 47,268.00	$ 92,184.00	-$ 139,452.00	$ 768,078.00	$ 65,312.00	$ 2,172,192.00	$ 613,078.00	$ -
Retirements/Removals (if applicable)								
UCC Before Half Year Rule	$ 47,268.00	$ 115,818.00	-$ 93,360.00	$ 628,626.00	$ 449,351.00	$ 2,204,848.00	$ 1,699,174.00	$ 306,539.00
Half Year Rule (1/2 Additions - Disposals)	$ 23,634.00	$ 46,092.00	$ -	$ 384,039.00	$ 32,656.00	$ 1,086,096.00	$ 306,539.00	$ -
Reduced UCC	$ 23,634.00	$ 69,726.00	$ 46,092.00	$ 244,587.00	$ 416,695.00	$ 1,118,752.00	$ 1,392,635.00	$ 306,539.00
CCA Rate Class	12	12	12	12	12	12	12	12
CCA Rate	100%	100%	100%	100%	100%	100%	100%	100%
CCA	$ 23,634.00	$ 69,726.00	$ 46,092.00	$ 244,587.00	$ 416,695.00	$ 1,118,752.00	$ 1,392,635.00	$ 306,539.00
Closing UCC	$ 23,634.00	$ 46,092.00	$ -	$ 384,039.00	$ 32,656.00	$ 1,086,096.00	$ 306,539.00	$ -

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Forecast	2013 Forecast
INCOME TAX								
Net Income	$ 3,596.63	$ 142,277.30	$ 351,239.14	$ 559,731.81	$ 779,329.46	$ 901,555.92	$ 910,322.04	$ 840,766.14
Amortization	$ 19,841.37	$ 328,592.67	$ 838,810.00	$ 1,316,629.90	$ 1,860,320.34	$ 2,382,426.93	$ 2,699,141.00	$ 2,726,115.00
CCA - Smart Meters	-$ 5,049.68	-$ 310,273.47	-$ 809,849.95	-$ 1,268,969.39	-$ 1,756,215.56	-$ 1,982,942.16	-$ 1,937,854.06	-$ 1,817,825.74
CCA - Computers	-$ 8,586.68	-$ 47,919.30	-$ 240,251.84	-$ 302,445.38	-$ 164,694.10	-$ 74,112.34	-$ 33,350.55	-$ 15,007.75
CCA - Applications Software	-$ 23,634.00	-$ 69,726.00	-$ 46,092.00	-$ 244,587.00	-$ 416,695.00	-$ 1,118,752.00	-$ 1,392,635.00	-$ 306,539.00
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	-$ 13,832.36	$ 42,951.21	$ 93,855.35	$ 60,359.95	$ 302,045.14	$ 108,176.36	$ 245,623.42	$ 1,427,508.66
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Income Taxes Payable	-$ 4,996.25	$ 15,513.98	$ 31,441.54	$ 19,918.78	$ 93,633.99	$ 30,559.82	$ 64,476.15	$ 364,014.71
ONTARIO CAPITAL TAX								
Smart Meters	$ 122,033.93	$ 7,377,588.07	$ 12,286,451.07	$ 18,656,151.06	$ 24,249,943.13	$ 24,285,287.19	$ 23,148,371.19	$ 21,107,288.19
Computer Hardware	$ 34,346.70	$ 165,153.90	$ 557,175.90	$ 515,139.90	$ 358,377.90	$ 205,572.90	$ 76,287.90	$ 10,748.90
Computer Software (Including Application Software)	$ 35,451.00	$ 80,955.00	$ -	$ 729,940.10	$ 714,815.70	$ 2,585,723.70	$ 2,640,861.70	$ 2,021,368.70
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ 191,831.63	$ 7,623,696.97	$ 12,843,626.97	$ 19,901,231.06	$ 25,323,136.73	$ 27,076,583.79	$ 25,865,520.79	$ 23,139,405.79
Less: Exemption								
Deemed Taxable Capital	$ 191,831.63	$ 7,623,696.97	$ 12,843,626.97	$ 19,901,231.06	$ 25,323,136.73	$ 27,076,583.79	$ 25,865,520.79	$ 23,139,405.79
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ 575.49	$ 17,153.32	$ 28,898.16	$ 44,777.77	$ 18,992.35	$ -	$ -	$ -
Change in Income Taxes Payable	-$ 4,996.25	$ 15,513.98	$ 31,441.54	$ 19,918.78	$ 93,633.99	$ 30,559.82	$ 64,476.15	$ 364,014.71
Change in OCT	$ 575.49	$ 17,153.32	$ 28,898.16	$ 44,777.77	$ 18,992.35	$ -	$ -	$ -
PILs	-$ 4,420.75	$ 32,667.30	$ 60,339.70	$ 64,696.55	$ 112,626.35	$ 30,559.82	$ 64,476.15	$ 364,014.71
Gross Up PILs								
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%
Change in Income Taxes Payable	-$ 7,821.30	$ 24,286.13	$ 47,280.51	$ 29,729.53	$ 135,701.44	$ 42,592.09	$ 87,425.29	$ 488,610.35
Change in OCT	$ 575.49	$ 17,153.32	$ 28,898.16	$ 44,777.77	$ 18,992.35	$ -	$ -	$ -
PILs	**-$ 7,245.81**	**$ 41,439.44**	**$ 76,178.68**	**$ 74,507.30**	**$ 154,693.79**	**$ 42,592.09**	**$ 87,425.29**	**$ 488,610.35**

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
2006 Q1			Jan-06	2006	Q1	$ -	$ -	0.00%	$ -	$ -		
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	$ -	$ -	0.00%	$ -	$ -		
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	$ -	$ -	0.00%	$ -	$ -		
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	$ -	$ -	4.14%	$ -	$ -		
2007 Q1	4.59%	4.72%	May-06	2006	Q2	$ -	$ 57,739	4.14%	$ -	$ 57,739.33		
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	$ 57,739.33	$ 57,555	4.14%	$ 199.20	$ 115,493.51		
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	$ 115,294.31	$ 59,389	4.59%	$ 441.00	$ 175,124.75		
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	$ 174,683.75	$ 53,543	4.59%	$ 668.17	$ 228,894.81		
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	$ 228,226.64	$ 52,284	4.59%	$ 872.97	$ 281,383.78		
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	$ 280,510.81	$ 64,368	4.59%	$ 1,072.95	$ 345,951.76		
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	$ 344,878.81	$ 46,227	4.59%	$ 1,319.16	$ 392,424.73		
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	$ 391,105.57	$ 62,174	4.59%	$ 1,495.98	$ 454,775.55	$ 459,349.00	
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	$ 453,279.57	$ 56,396	4.59%	$ 1,733.79	$ 511,409.64		
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	$ 509,675.85	$ 50,840	4.59%	$ 1,949.51	$ 562,465.40		
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	$ 560,515.89	$ 59,789	4.59%	$ 2,143.97	$ 622,449.22		
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	$ 620,305.25	$ 56,032	4.59%	$ 2,372.67	$ 678,710.01		
2010 Q1	0.55%	4.34%	May-07	2007	Q2	$ 676,337.34	$ 235,501	4.59%	$ 2,586.99	$ 914,424.97		
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	$ 911,837.98	$ 234,295	4.59%	$ 3,487.78	$ 1,149,620.27		
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	$ 1,146,132.49	$ 246,302	4.59%	$ 4,383.96	$ 1,396,818.51		
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	$ 1,392,434.55	$ 235,357	4.59%	$ 5,326.06	$ 1,633,117.88		
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	$ 1,627,791.82	$ 227,262	4.59%	$ 6,226.30	$ 1,861,279.90		
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	$ 1,855,053.60	$ 238,939	5.14%	$ 7,945.81	$ 2,101,938.72		
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	$ 2,093,992.91	$ 230,424	5.14%	$ 8,969.27	$ 2,333,386.31		
2011 Q4	1.47%	3.92%	Dec-07	2007	Q4	$ 2,324,417.04	$ 242,554	5.14%	$ 9,956.25	$ 2,576,926.95	$ 2,170,773.49	
2012 Q1	1.47%	3.92%	Jan-08	2008	Q1	$ 2,566,970.70	$ 241,663	5.14%	$ 10,995.19	$ 2,819,629.38		
2012 Q2			Feb-08	2008	Q1	$ 2,808,634.19	$ 222,523	5.14%	$ 12,030.32	$ 3,043,187.65		
2012 Q3			Mar-08	2008	Q1	$ 3,031,157.33	$ 248,436	5.14%	$ 12,983.46	$ 3,292,576.62		

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP
2012 Q4		
2013 Q1		
2013 Q2		
2013 Q3		
2013 Q4		

Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
Apr-08	2008	Q2	$ 3,279,593.16	$ 238,797	4.08%	$ 11,150.62	$ 3,529,540.46		
May-08	2008	Q2	$ 3,518,389.84	$ 111,425	4.08%	$ 11,962.53	$ 3,641,776.96		
Jun-08	2008	Q2	$ 3,629,814.43	$ 102,988	4.08%	$ 12,341.37	$ 3,745,143.32		
Jul-08	2008	Q3	$ 3,732,801.95	$ 106,516	3.35%	$ 10,420.74	$ 3,849,739.08		
Aug-08	2008	Q3	$ 3,839,318.34	$ 105,404	3.35%	$ 10,718.10	$ 3,955,440.85		
Sep-08	2008	Q3	$ 3,944,722.75	$ 106,709	3.35%	$ 11,012.35	$ 4,062,444.31		
Oct-08	2008	Q4	$ 4,051,431.96	$ 107,089	3.35%	$ 11,310.25	$ 4,169,831.44		
Nov-08	2008	Q4	$ 4,158,521.19	$ 105,094	3.35%	$ 11,609.20	$ 4,275,224.64		
Dec-08	2008	Q4	$ 4,263,615.44	$ 108,698	3.35%	$ 11,902.59	$ 4,384,215.56	$ 1,943,778.99	
Jan-09	2009	Q1	$ 4,372,312.97	$ 105,680	2.45%	$ 8,926.81	$ 4,486,920.02		
Feb-09	2009	Q1	$ 4,477,993.21	$ 99,158	2.45%	$ 9,142.57	$ 4,586,294.06		
Mar-09	2009	Q1	$ 4,577,151.49	$ 117,564	2.45%	$ 9,345.02	$ 4,704,060.41		
Apr-09	2009	Q2	$ 4,694,715.39	$ 107,968	1.00%	$ 3,912.26	$ 4,806,595.24		
May-09	2009	Q2	$ 4,802,682.98	$ 264,330	1.00%	$ 4,002.24	$ 5,071,015.02		
Jun-09	2009	Q2	$ 5,067,012.78	$ 271,289	1.00%	$ 4,222.51	$ 5,342,523.95		
Jul-09	2009	Q3	$ 5,338,301.44	$ 272,292	0.55%	$ 2,446.72	$ 5,613,040.59		
Aug-09	2009	Q3	$ 5,610,593.87	$ 265,750	0.55%	$ 2,571.52	$ 5,878,915.17		
Sep-09	2009	Q3	$ 5,876,343.65	$ 258,003	0.55%	$ 2,693.32	$ 6,137,040.08		
Oct-09	2009	Q4	$ 6,134,346.76	$ 263,084	0.55%	$ 2,811.58	$ 6,400,241.88		
Nov-09	2009	Q4	$ 6,397,430.30	$ 277,559	0.55%	$ 2,932.16	$ 6,677,921.66		
Dec-09	2009	Q4	$ 6,674,989.50	$ 283,829	0.55%	$ 3,059.37	$ 6,961,877.57	$ 2,642,571.31	
Jan-10	2010	Q1	$ 6,958,818.20	$ 260,928	0.55%	$ 3,189.46	$ 7,222,935.61		
Feb-10	2010	Q1	$ 7,219,746.15	$ 244,171	0.55%	$ 3,309.05	$ 7,467,225.79		
Mar-10	2010	Q1	$ 7,463,916.74	$ 288,267	0.55%	$ 3,420.96	$ 7,755,604.87		
Apr-10	2010	Q2	$ 7,752,183.91	$ 264,354	0.55%	$ 3,553.08	$ 8,020,090.84		
May-10	2010	Q2	$ 8,016,537.76	$ 417,604	0.55%	$ 3,674.25	$ 8,437,816.21		
Jun-10	2010	Q2	$ 8,434,141.96	$ 417,533	0.55%	$ 3,865.65	$ 8,855,540.73		
Jul-10	2010	Q3	$ 8,851,675.08	$ 405,683	0.89%	$ 6,564.99	$ 9,263,922.83		

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Aug-10	2010	Q3	$ 9,257,357.84	$ 416,927	0.89%	$ 6,865.87	$ 9,681,150.71		
			Sep-10	2010	Q3	$ 9,674,284.84	$ 400,955	0.89%	$ 7,175.09	$ 10,082,414.93		
			Oct-10	2010	Q4	$ 10,075,239.84	$ 439,801	1.20%	$ 10,075.24	$ 10,525,116.08		
			Nov-10	2010	Q4	$ 10,515,040.84	$ 443,658	1.20%	$ 10,515.04	$ 10,969,213.88		
			Dec-10	2010	Q4	$ 10,958,698.84	$ 435,832	1.20%	$ 10,958.70	$ 11,405,489.54	$ 4,508,880.03	
			Jan-11	2011	Q1	$ 11,394,530.84	$ 411,831	1.47%	$ 13,958.30	$ 11,820,320.44		
			Feb-11	2011	Q1	$ 11,806,362.14	$ 381,217	1.47%	$ 14,462.79	$ 12,202,041.93		
			Mar-11	2011	Q1	$ 12,187,579.14	$ 456,018	1.47%	$ 14,929.78	$ 12,658,526.92		
			Apr-11	2011	Q2	$ 12,643,597.14	$ 455,890	1.47%	$ 15,488.41	$ 13,114,975.60		
			May-11	2011	Q2	$ 13,099,487.19	$ 439,690	1.47%	$ 16,046.87	$ 13,555,223.69		
			Jun-11	2011	Q2	$ 13,539,176.82	$ 394,899	1.47%	$ 16,585.49	$ 13,950,661.23		
			Jul-11	2011	Q3	$ 13,934,075.74	$ 392,279	1.47%	$ 17,069.24	$ 14,343,423.49		
			Aug-11	2011	Q3	$ 14,326,354.25	$ 414,450	1.47%	$ 17,549.78	$ 14,758,354.03		
			Sep-11	2011	Q3	$ 14,740,804.25	$ 408,741	1.47%	$ 18,057.49	$ 15,167,603.09		
			Oct-11	2011	Q4	$ 15,149,545.60	$ 408,491.90	1.47%	$ 18,558.19	$ 15,576,595.69		
			Nov-11	2011	Q4	$ 15,558,037.50	$ 422,698.22	1.47%	$ 19,058.60	$ 15,999,794.32		
			Dec-11	2011	Q4	$ 15,980,735.72	$ 413,778.71	1.47%	$ 19,576.40	$ 16,414,090.83	$ 5,201,324.93	
			Jan-12	2012	Q1	$ 16,394,514.43	$ 410,000.00	1.47%	$ 20,083.28	$ 16,824,597.71		
			Feb-12	2012	Q1	$ 16,804,514.43	$ 410,000.00	1.47%	$ 20,585.53	$ 17,235,099.96		
			Mar-12	2012	Q1	$ 17,214,514.43	$ 410,000.00	1.47%	$ 21,087.78	$ 17,645,602.21		
			Apr-12	2012	Q2	$ 17,624,514.43	$ 410,000.00	1.47%	$ 21,590.03	$ 18,056,104.46		
			May-12	2012	Q2	$ 18,034,514.43	$ 150,000.00	1.47%	$ 22,092.28	$ 18,206,606.71		
			Jun-12	2012	Q2	$ 18,184,514.43	$ 150,000.00	1.47%	$ 22,276.03	$ 18,356,790.46		
			Jul-12	2012	Q3	$ 18,334,514.43	$ 150,000.00	1.47%	$ 22,459.78	$ 18,506,974.21		
			Aug-12	2012	Q3	$ 18,484,514.43	$ 150,000.00	1.47%	$ 22,643.53	$ 18,657,157.96		
			Sep-12	2012	Q3	$ 18,634,514.43	$ 150,000.00	1.47%	$ 22,827.28	$ 18,807,341.71		
			Oct-12	2012	Q4	$ 18,784,514.43	$ 150,000.00	1.47%	$ 23,011.03	$ 18,957,525.46		
			Nov-12	2012	Q4	$ 18,934,514.43	$ 150,000.00	1.47%	$ 23,194.78	$ 19,107,709.21		
			Dec-12	2012	Q4	$ 19,084,514.43	$ 150,000.00	1.47%	$ 23,378.53	$ 19,257,892.96	$ 3,105,229.86	
			Jan-13	2013	Q1	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Feb-13	2013	Q1	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Mar-13	2013	Q1	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Apr-13	2013	Q2	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			May-13	2013	Q2	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Jun-13	2013	Q2	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Jul-13	2013	Q3	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Aug-13	2013	Q3	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Sep-13	2013	Q3	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Oct-13	2013	Q4	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Nov-13	2013	Q4	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43		
			Dec-13	2013	Q4	$ 19,234,514.43		0.00%	$ -	$ 19,234,514.43	$ -	
			Total Funding Adder Revenues Collected				**$ 19,234,514.43**		**$ 797,393.17**	**$ 20,031,907.60**	**$ 20,031,907.60**	

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
2006 Q1	0.00%	0.00%	Jan-06	2006	Q1	$ -			-	0.00%	-	-
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	-			-	0.00%	-	-
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	-			-	0.00%	-	-
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	-			-	4.14%	-	-
2007 Q1	4.59%	4.72%	May-06	2006	Q2	-	$ 6,520.86		6,520.86	4.14%	-	-
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	6,520.86			6,520.86	4.14%	22.50	22.50
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	6,520.86			6,520.86	4.59%	24.94	47.44
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	6,520.86			6,520.86	4.59%	24.94	72.38
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	6,520.86			6,520.86	4.59%	24.94	97.32
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	6,520.86		$ 780.00	7,300.86	4.59%	24.94	122.27
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	7,300.86		$ 1,959.30	9,260.16	4.59%	27.93	150.19
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	9,260.16	$ 20,082.73	$ 17,102.06	46,444.95	4.59%	35.42	185.61
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	46,444.95		$ 3,337.34	49,782.29	4.59%	177.65	363.26
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	49,782.29		$ 3,989.31	53,771.60	4.59%	190.42	553.68
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	53,771.60	$ 33,648.21	$ 12,313.69	99,733.50	4.59%	205.68	759.36
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	99,733.50	$ 33,035.65	$ 14,358.21	147,127.36	4.59%	381.48	1,140.84
2010 Q1	0.55%	4.34%	May-07	2007	Q2	147,127.36	$ 114,899.37	$ 15,870.75	277,897.48	4.59%	562.76	1,703.60
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	277,897.48	$ 43,829.93	$ 22,073.28	343,800.69	4.59%	1,062.96	2,766.56
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	343,800.69	$ 79,068.55	$ 31,615.86	454,485.10	4.59%	1,315.04	4,081.60
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	454,485.10	$ 28,171.34	$ 37,977.41	520,633.85	4.59%	1,738.41	5,820.00
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	520,633.85	$ 70,373.52	$ 31,985.38	622,992.75	4.59%	1,991.42	7,811.43
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	622,992.75	$ 45,984.23	$ 56,176.85	725,153.83	5.14%	2,668.49	10,479.91
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	725,153.83	$ 134,446.95	$ 37,897.11	897,497.89	5.14%	3,106.08	13,585.99
2011 Q4	1.47%	3.92%	Dec-07	2007	Q4	897,497.89	-$ 287,571.78	$ 60,997.47	670,923.58	5.14%	3,844.28	17,430.27
2012 Q1	1.47%	3.92%	Jan-08	2008	Q1	670,923.58	$ 12,862.21	$ 3,462.85	687,248.64	5.14%	2,873.79	20,304.06
2012 Q2	0.00%	0.00%	Feb-08	2008	Q1	687,248.64	$ 12,852.62	$ 51,792.69	751,893.95	5.14%	2,943.72	23,247.77
2012 Q3	0.00%	0.00%	Mar-08	2008	Q1	751,893.95	$ 56,899.35	$ 52,214.52	861,007.82	5.14%	3,220.61	26,468.39
2012 Q4	0.00%	0.00%	Apr-08	2008	Q2	861,007.82	$ 30,157.51	$ 52,072.10	943,237.43	4.08%	2,927.43	29,395.81
2013 Q1	0.00%	0.00%	May-08	2008	Q2	943,237.43	$ 86,254.03	$ 54,563.38	1,084,054.84	4.08%	3,207.01	32,602.82
2013 Q2	0.00%	0.00%	Jun-08	2008	Q2	1,084,054.84	$ 67,705.41	$ 56,736.00	1,208,496.25	4.08%	3,685.79	36,288.61
2013 Q3	0.00%	0.00%	Jul-08	2008	Q3	1,208,496.25	$ 188,078.30	$ 63,436.88	1,460,011.43	3.35%	3,373.72	39,662.33
2013 Q4	0.00%	0.00%	Aug-08	2008	Q3	1,460,011.43	-$ 6,391.50	$ 62,815.05	1,516,434.98	3.35%	4,075.87	43,738.19
			Sep-08	2008	Q3	1,516,434.98	$ 76,199.65	$ 128,828.67	1,721,463.30	3.35%	4,233.38	47,971.57
			Oct-08	2008	Q4	1,721,463.30	$ 48,771.37	$ 108,687.08	1,878,921.75	3.35%	4,805.75	52,777.32
			Nov-08	2008	Q4	1,878,921.75	-$ 433,509.36	$ 128,201.62	1,573,614.01	3.35%	5,245.32	58,022.65

Dec-08	2008	Q4	1,573,614.01	-$ 45,738.49	$ 75,999.77	1,603,875.29	3.35%	4,393.01	62,415.65
Jan-09	2009	Q1	1,603,875.29	-$ 13,693.52	$ 85,658.37	1,675,840.14	2.45%	3,274.58	65,690.23
Feb-09	2009	Q1	1,675,840.14	-$ 77,721.05	$ 90,199.48	1,688,318.57	2.45%	3,421.51	69,111.74
Mar-09	2009	Q1	1,688,318.57	-$ 89,902.56	$ 98,046.09	1,696,462.10	2.45%	3,446.98	72,558.72
Apr-09	2009	Q2	1,696,462.10	-$ 1,851.39	$ 100,982.41	1,795,593.12	1.00%	1,413.72	73,972.44
May-09	2009	Q2	1,795,593.12	-$ 133,549.81	$ 113,237.04	1,775,280.35	1.00%	1,496.33	75,468.77
Jun-09	2009	Q2	1,775,280.35	$ 155,194.71	$ 100,477.11	2,030,952.17	1.00%	1,479.40	76,948.17
Jul-09	2009	Q3	2,030,952.17	-$ 78,122.34	$ 107,768.40	2,060,598.23	0.55%	930.85	77,879.02
Aug-09	2009	Q3	2,060,598.23	-$ 42,033.33	$ 107,096.52	2,125,661.42	0.55%	944.44	78,823.46
Sep-09	2009	Q3	2,125,661.42	-$ 54,434.29	$ 111,304.66	2,182,531.79	0.55%	974.26	79,797.72
Oct-09	2009	Q4	2,182,531.79	-$ 20,306.59	$ 114,760.49	2,276,985.69	0.55%	1,000.33	80,798.05
Nov-09	2009	Q4	2,276,985.69	$ 42,787.60	$ 123,303.95	2,443,077.24	0.55%	1,043.62	81,841.67
Dec-09	2009	Q4	2,443,077.24	-$ 18,671.26	$ 163,795.70	2,588,201.67	0.55%	1,119.74	82,961.41
Jan-10	2010	Q1	2,588,201.67	-$ 24,412.43	$ 135,899.44	2,699,688.68	0.55%	1,186.26	84,147.67
Feb-10	2010	Q1	2,699,688.68	-$ 478,959.07	$ 139,351.07	2,360,080.68	0.55%	1,237.36	85,385.03
Mar-10	2010	Q1	2,360,080.68	$ 438,825.15	$ 141,878.55	2,940,784.38	0.55%	1,081.70	86,466.73
Apr-10	2010	Q2	2,940,784.38	-$ 242,058.57	$ 144,996.13	2,843,721.94	0.55%	1,347.86	87,814.59
May-10	2010	Q2	2,843,721.94	-$ 199,664.90	$ 146,787.24	2,790,844.27	0.55%	1,303.37	89,117.96
Jun-10	2010	Q2	2,790,844.27	$ 481,761.97	$ 158,426.26	3,431,032.51	0.55%	1,279.14	90,397.10
Jul-10	2010	Q3	3,431,032.51	-$ 101,325.04	$ 155,671.34	3,485,378.81	0.89%	2,544.68	92,941.78
Aug-10	2010	Q3	3,485,378.81	$ 16,579.02	$ 160,438.21	3,662,396.03	0.89%	2,584.99	95,526.77
Sep-10	2010	Q3	3,662,396.03	$ 613,028.05	$ 168,720.13	4,444,144.21	0.89%	2,716.28	98,243.05
Oct-10	2010	Q4	4,444,144.21	$ 130,860.95	$ 174,557.32	4,749,562.48	1.20%	4,444.14	102,687.19
Nov-10	2010	Q4	4,749,562.48	$ 144,396.00	$ 187,599.06	5,081,557.54	1.20%	4,749.56	107,436.76
Dec-10	2010	Q4	5,081,557.54	$ 138,621.00	$ 145,995.61	5,366,174.15	1.20%	5,081.56	112,518.31
Jan-11	2011	Q1	5,366,174.15	-$ 25,265.15	$ 170,091.95	5,511,000.95	1.47%	6,573.56	119,091.88
Feb-11	2011	Q1	5,511,000.95	$ 15,687.00	$ 170,450.58	5,697,138.53	1.47%	6,750.98	125,842.85
Mar-11	2011	Q1	5,697,138.53	$ 21,375.00	$ 190,940.19	5,909,453.72	1.47%	6,978.99	132,821.85
Apr-11	2011	Q2	5,909,453.72	-$ 2,140.00	$ 182,194.39	6,089,508.11	1.47%	7,239.08	140,060.93
May-11	2011	Q2	6,089,508.11	$ 42,732.15	$ 180,338.77	6,312,579.03	1.47%	7,459.65	147,520.58
Jun-11	2011	Q2	6,312,579.03	$ 69,693.00	$ 177,648.69	6,559,920.72	1.47%	7,732.91	155,253.49
Jul-11	2011	Q3	6,559,920.72	$ 49,812.78	$ 180,865.73	6,790,599.23	1.47%	8,035.90	163,289.39
Aug-11	2011	Q3	6,790,599.23	$ 53,414.68	$ 181,260.57	7,025,274.48	1.47%	8,318.48	171,607.87
Sep-11	2011	Q3	7,025,274.48	$ 66,461.54	$ 179,418.89	7,271,154.91	1.47%	8,605.96	180,213.83
Oct-11	2011	Q4	7,271,154.91	$ 52,753.82	$ 354,914.81	7,678,823.54	1.47%	8,907.16	189,121.00
Nov-11	2011	Q4	7,678,823.54	$ 169,046.52	$ 210,564.21	8,058,434.27	1.47%	9,406.56	198,527.56
Dec-11	2011	Q4	8,058,434.27	$ 237,587.71	$ 203,737.77	8,499,759.75	1.47%	9,871.58	208,399.14
Jan-12	2012	Q1	8,499,759.75	$ 52,903.00	$ 224,928.42	8,777,591.17	1.47%	10,412.21	218,811.35
Feb-12	2012	Q1	8,777,591.17	$ 52,903.00	$ 224,928.42	9,055,422.58	1.47%	10,752.55	229,563.90
Mar-12	2012	Q1	9,055,422.58	$ 52,903.00	$ 224,928.42	9,333,254.00	1.47%	11,092.89	240,656.79
Apr-12	2012	Q2	9,333,254.00	$ 52,903.00	$ 224,928.42	9,611,085.42	1.47%	11,433.24	252,090.02
May-12	2012	Q2	9,611,085.42	$ 52,903.00	$ 224,928.42	9,888,916.83	1.47%	11,773.58	263,863.60
Jun-12	2012	Q2	9,888,916.83	$ 52,903.00	$ 224,928.42	10,166,748.25	1.47%	12,113.92	275,977.53
Jul-12	2012	Q3	10,166,748.25	$ 52,903.00	$ 224,928.42	10,444,579.67	1.47%	12,454.27	288,431.79
Aug-12	2012	Q3	10,444,579.67	$ 52,903.00	$ 224,928.42	10,722,411.08	1.47%	12,794.61	301,226.40
Sep-12	2012	Q3	10,722,411.08	$ 52,903.00	$ 224,928.42	11,000,242.50	1.47%	13,134.95	314,361.36
Oct-12	2012	Q4	11,000,242.50	$ 52,903.00	$ 224,928.42	11,278,073.92	1.47%	13,475.30	327,836.65
Nov-12	2012	Q4	11,278,073.92	$ 52,903.00	$ 224,928.42	11,555,905.33	1.47%	13,815.64	341,652.29
Dec-12	2012	Q4	11,555,905.33	$ 52,901.99	$ 224,928.42	11,833,735.74	1.47%	14,155.98	355,808.28
Jan-13	2013	Q1	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Feb-13	2013	Q1	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Mar-13	2013	Q1	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Apr-13	2013	Q2	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
May-13	2013	Q2	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Jun-13	2013	Q2	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Jul-13	2013	Q3	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Aug-13	2013	Q3	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Sep-13	2013	Q3	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Oct-13	2013	Q4	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Nov-13	2013	Q4	11,833,735.74			11,833,735.74	0.00%	-	355,808.28
Dec-13	2013	Q4	11,833,735.74			11,833,735.74	0.00%	-	355,808.28

$ 2,387,973.00	$ 9,445,762.74	$ 11,833,735.74

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	OM&A (from Sheet 5)	Amortization Expense (from Sheet 5)	Cumulative OM&A and Amortization Expense	Average Cumulative OM&A and Amortization Expense	Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)	Simple Interest on OM&A and Amortization Expenses
2006	$ 26,603.00	$ 19,841.37	$ 46,444.37	$ 23,222.18	4.37%	$ 1,013.65
2007	$ 295,887.00	$ 328,592.67	$ 670,924.03	$ 358,684.20	4.73%	$ 16,956.80
2008	$ 94,140.00	$ 838,810.00	$ 1,603,874.03	$ 1,137,399.03	3.98%	$ 45,268.48
2009	-$ 332,304.00	$ 1,316,629.90	$ 2,588,199.94	$ 2,096,036.99	1.14%	$ 23,842.42
2010	$ 917,652.00	$ 1,860,320.34	$ 5,366,172.27	$ 3,977,186.11	0.80%	$ 31,718.06
2011	$ 751,159.00	$ 2,382,426.93	$ 8,499,758.21	$ 6,932,965.24	1.47%	$ 101,914.59
2012	$ 634,836.00	$ 2,699,141.00	$ 11,833,735.21	$ 10,166,746.71	1.47%	$ 149,451.18
2013	$ 180,228.00	$ 2,726,115.00	$ 14,740,078.21	$ 13,286,906.71	0.00%	$ -
Cumulative Interest to 2011						$ 220,713.99
Cumulative Interest to 2012						$ 370,165.17
Cumulative Interest to 2013						$ 370,165.17

Ontario Energy Board

Smart Meter Model

Enersource Hydro Mississauga Inc.

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board 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. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should 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. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable		
	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2011**
	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	**The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2012 and associated OM&A.**

	2006	2007	2008	2009	2010	2011	2012	2013	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ 46,655.56	$ 960,907.39	$ 1,748,206.32	$ 2,236,621.27	$ 4,572,531.72	$ 5,073,232.62	$ 5,336,902.57	$ 4,675,483.71	$ 19,975,057.45
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B)	$ 185.61	$ 17,244.66	$ 44,985.38	$ 20,545.76	$ 29,556.90	$ 95,880.83	$ 147,409.14		$ 355,808.28
(Check **one** of the boxes below)									
X Sheet 8A (Interest calculated on monthly balances)	$ 185.61	$ 17,244.66	$ 44,985.38	$ 20,545.76	$ 29,556.90	$ 95,880.83	$ 147,409.14	$ -	$ 355,808.28
Sheet 8B (Interest calculated on average annual balances)									
SMFA Revenues (from Sheet 8)	$ 453,279.57	$ 2,113,691.13	$ 1,805,342.27	$ 2,586,505.23	$ 4,435,712.65	$ 4,999,983.59	$ 2,840,000.00	$ -	$ 19,234,514.43
SMFA Interest (from Sheet 8)	$ 6,069.43	$ 57,082.36	$ 138,436.72	$ 56,066.08	$ 73,167.38	$ 201,341.34	$ 265,229.86	$ -	$ 797,393.17
Net Deferred Revenue Requirement	-$ 412,507.83	-$ 1,192,621.44	-$ 150,587.28	-$ 385,404.28	$ 93,208.60	-$ 32,211.48	$ 2,379,081.84	$ 4,675,483.71	$ 298,958.13
Number of Metered Customers (average for 2013 test year) - Number of metered customers for which smart meter were deployed as part of program). Residential and GS < 50 kW customer classes and any other metered classes involved (e.g. GS 50 to 4999 kW for which interval meters were upgraded to utilize AMI and ODS assets)								198518	

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		1
Deferred Incremental Revenue Requirement from 2006 to December 31, 2012 plus Interest on OM&A and Amortization		$ 20,330,865.73
SMFA Revenues collected from 2006 to 2013 test year (inclusive) Plus Simple Interest on SMFA Revenues		$ 20,031,907.60
Net Deferred Revenue Requirement		$ 298,958.13
SMDR	January 1, 2013 to December 31, 2013	$ 0.13
Check: Forecasted SMDR Revenues		$ 309,688.08
Check: Forecasted SMIRR Revenues		$ 4,669,143.36

Match

Appendix 2-Q
Smart Meters

Irrespective of whether a distributor is actively deploying smart meters (except if the distributor has completed its smart meter deployment program and has had Board-approved disposition of the balances in accounts 1555 and 1556) the distributor should provide a completed table as follows:

Year	Smart Meters Installed			Percentage of applicable customers converted	Account 1555		Account 1556
	Residential	GS < 50 kW	Other [1]		Funding Adder Revenues Collected	Capital Expenditures	Operating Expenses [2]
				%	$	$	$
2006	2,680	-	-	1%	$ 459,349	$ 211,673	$ 26,603
2007	57,856	-	-	31%	$ 2,170,773	$ 7,760,458	$ 295,887
2008	48,537	1,763	-	57%	$ 1,943,779	$ 6,058,740	$ 94,140
2009	33,817	-	705	75%	$ 2,642,571	$ 8,374,234	-$ 332,304
2010	21,421	6,507	802	90%	$ 4,508,880	$ 7,282,226	$ 917,652
2011	9,632	7,335	- 97	99%	$ 5,201,325	$ 4,135,874	$ 751,159
2012 (Forecasted)	924	1,680	-	100%	$ 3,105,230	$ 1,488,078	$ 634,836

[1] Other relates to GS > 50 KW customers ("collateral customers") that have been converted to "smart meters". Refer to Exhibit 9, Tab 2, Schedule 1.

[2] Operating expenses excludes depreciation/amortization.

In addition, a distributor that is requesting an increase to its current approved smart meter funding adder (e.g. to $1.00 or another utility-specific amount), should provide the information required to support such a request in accordance with section 1.4 of*Guideline G-2008-0002: Smart Meter Funding and Cost Recovery*, or any successor document. Applicants should note that continuation of a smart meter funding adder past April 30, 2012 will only be allowed by the Board in exceptional circumstances.

Any request for disposition or partial disposition of the balances in accounts 1555 and 1556 should be supported by smart meter costs information that has been audited in accordance with the requirements of Guideline G-2008-0002 or further information communicated by the Board.

Stranded Conventional Meters

In accordance with the Board's Guideline G-2011-0001, whereby distributors are to be "held whole with respect to the cost recovery of stranded meters (i.e., conventional meters replaced as part of the smart meter initiative)"[1], Enersource seeks disposition of its stranded meter costs as at December 31, 2012. Historical stranded conventional meter gross asset values and net book values are shown in Table 1 below. Please also refer to Exhibit 9 Tab 2 Schedule 2 Appendix 2-R.

Table 1: Residual Net Book Value of Stranded Meters ($000s)

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ -	$ -	$ -	$ -	$ -	$ -
2007		$ 7,397	$ 5,840	$ -	$ 1,557	$ 28	$ 1,530
2008		$ 16,372	$ 13,321	$ -	$ 3,051	$ 68	$ 2,983
2009		$ 24,434	$ 18,657	$ -	$ 5,778	$ 105	$ 5,673
2010		$ 29,207	$ 21,483	$ -	$ 7,724	$ 138	$ 7,586
2011		$ 30,465	$ 22,905	$ -	$ 7,560	$ 150	$ 7,411
2012	(1)	$ 32,265	$ 24,476	$ -	$ 7,789	$ 150	$ 7,640

Notes: (1) The amounts provided are forecast as of December 31, 2012.

The stranded meter accounting treatment followed by Enersource is in accordance with Guideline G-2011-0001, whereby the stranded meters are recorded in Account 1555 Sub-account Stranded Meter Costs. The allocation of

[1] *OEB G-2011-0001 Guideline Smart Meter Funding and Cost Recovery – Final Disposition*, dated December 15, 2011, p. 21.

stranded meters to Account 1555 is based on the estimated average net book value of the conventional meters that became stranded during the year, as described in the Combined Smart Meter Proceeding (EB-2007-0063). The forecasted net book value of stranded meters at December 31, 2012 is $7,789, which includes the reduction of the net book value for depreciation occurring after the meters were removed from service. After deducting the proceeds on disposition from the sale of scrap materials totalling $150, the forecasted amount of stranded meters requested for disposition at December 31, 2012 is $7,640.

The total depreciation expense for the period from the time the conventional meters were removed from service and became stranded and were transferred to the sub-account to December 31, 2012 is forecasted to be $4,589.

If Enersource had chosen the alternative accounting treatment for stranded meters whereby all stranded meter costs remained in Account 1860 Meters, the same forecasted net book value at December 31, 2012 of $7,640 would have resulted. See Table 2 below.

Table 2: Stranded Meters Net Book Value if Remained in Account 1860 ($000s)

	September 2006 (1)	December 2006	December 2007	December 2008
Gross Cost	$ 32,265	$ 32,265	$ 32,265	$ 32,265
Accumulated Depreciation	$ (16,962)	$ (17,280)	$ (18,547)	$ (19,803)
Net Book Value	$ 15,304	$ 14,985	$ 13,719	$ 12,462

	December 2009	December 2010	December 2011	December 2012 (2)
Gross Cost	$ 32,265	$ 32,265	$ 32,265	$ 32,265
Accumulated Depreciation	$ (21,034)	$ (22,253)	$ (23,405)	$ (24,476)
Net Book Value	$ 11,232	$ 10,012	$ 8,860	$ 7,789

Forecasted net book value at December 31, 2012	$ 7,789
Less: Proceeds on Disposition of Scrap Materials	$ (150)
Stranded Meters Requested for Disposition	$ 7,640

Notes:

(1) September 2006 net book value equal to net book value provided in Combined Smart Meter Proceeding (EB-2007-0063).

(2) December 2012 amount is forecasted.

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Enersource confirms that carrying charges have not been recorded for the stranded meter cost balances in the sub-account.

Disposition and Allocation of Stranded Meter Costs

Adhering to the guidance in:

- Section 2.5.1.5 *Treatment of Stranded Assets Related to Smart Meter Deployment* in the June 22, 2011 *Chapter 2 Filing Requirements for Transmission and Distribution Applications*; and
- the Decision and Order of April 4, 2011 with respect to HONI Brampton (EB-2010-0132);

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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Appendix 2-R
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006		$ -	$ -	$ -	$ -	$ -	$ -
2007		$ 7,397,273	$ 5,839,775	$ -	$ 1,557,498	$ 27,611	$ 1,529,887
2008		$ 16,372,178	$ 13,320,702	$ -	$ 3,051,476	$ 68,333	$ 2,983,143
2009		$ 24,434,462	$ 18,656,661	$ -	$ 5,777,801	$ 104,523	$ 5,673,278
2010		$ 29,206,897	$ 21,483,232	$ -	$ 7,723,665	$ 137,541	$ 7,586,124
2011		$ 30,465,489	$ 22,905,051	$ -	$ 7,560,438	$ 149,638	$ 7,410,800
2012	(1)	$ 32,265,409	$ 24,476,132	$ -	$ 7,789,277	$ 149,638	$ 7,639,639

Notes:

(1) *For 2012, the amounts provided are on a forecast basis.*

Some distributors have transferred the cost of stranded meters from Account 1860 - Meters to "Sub-account Stranded Meter Costs of Account 1555", while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen. please provide the information under either of the two scenarios (A and B below), as applicable.

Scenario A: *If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555, the above table should be completed and the following information should be provided.*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

Enersource: Refer to Exhibit 9 Tab 2 Schedule 2

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, which were transferred to this sub-account as of December 31, 2011.

3 A statement as to whether or not, since transferring the removed stranded meter costs to the sub-account, the recording of depreciation expenses was continued in order to reduce the net book value through accumulated depreciation. If so, the total depreciation expense amount for the period from the time the costs for the stranded meters were transferred to the sub-account to December 31, 2011 should be provided.

Enersource: Refer to Exhibit 9 Tab 2 Schedule 2
If no depreciation expenses were recorded to reduce the net book value of stranded meter costs through accumulated depreciation, the total depreciation expense amount that would have been applicable from the time that the stranded meter costs were transferred to the sub-account of Account 1555 to December 31, 2011 should be provided. In addition, the following information should be provided:

a) Whether or not carrying charges were recorded for the stranded meter cost balances in the sub-account, and if so, the total carrying charges recorded to December 31, 2011.

b) The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when the smart meters will have been fully deployed (e.g., as of December 31, 2011). If the smart meters have been fully deployed, the actual amount should be provided.

c) A description as to how the applicant intends to recover in rates the remaining costs for stranded meters, including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

Scenario B: *If the stranded meter costs remained recorded in Account 1860, the above table should be completed and the following information should be provided:*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2011.

3 A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2011.

4 If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2011.

5 The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

6 A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

Distributors should also provide the Net Book Value per class of meter as of December 31, 2011 as well as the number of meters that were removed / stranded. In preparing this information, distributors should review the Board's letter of January 16, 2007 *Stranded Meter Costs Related to the Installation of Smart Meters* which stated that records were to be kept of the type and number of each meter to support the stranded meter costs.