RATE BASE OVERVIEW

In accordance with s. 2.5.1.1 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements"), this schedule provides an overview of Toronto Hydro's rate base and year-over year variance analysis of rate base and distribution assets for the following years: 2011 OEB-approved, 2011 to 2013 historical actuals, 2014 bridge year forecast, and 2015 test year forecasts. Continuity statements for Toronto Hydro's fixed assets, including interest during construction and all overheads, are filed at Exhibit 2A, Tab 1, Schedule 2.

1. RATE BASE

Table 1 below summarizes Toronto Hydro's rate base values for the historical (2011 to 2013), bridge (2014), and test year (2015), including opening and closing balances, the average of opening and closing balances for gross assets and accumulated depreciation, and the utility's working capital allowance.

Table 1: Rate Base Overview ($ Millions)

	2011 OEB Approved	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2015 Test MIFRS
Opening PP&E NBV	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,436.6
ICM	-	-	-	-	-	372.6
Street Lighting	-	-	-	-	-	39.8
Opening PP&E NBV Adjusted	1,897.8	1,895.8	2,183.5	2,251.9	2,356.0	2,849.0
Closing PP&E NBV	2,105.1	2,183.5	2,251.9	2,356.0	2,456.3[1]	3,161.0
Average PP&E NBV	2,001.5	2,039.7	2,217.7	2,304.0	2,406.1	3,005.0
Working Capital Allowance	296.7	318.1	316.6	354.4	369.5	241.5
Rate Base	2,298.2	2,357.7	2,534.3	2,658.4	2,775.6	3,246.5

/C

[1] The 2014 financial results have not been closed out and audited. However, Toronto Hydro's assessment is that the 2014 closing PP&E NBV is within approximately 1% of the forecast.

For the purpose of the test year revenue requirement (Exhibit 6, Tab 1, Schedule 1),[1] rate base includes the average of the opening and closing balances for the net book value of property, plant and equipment plus a working capital allowance. The net book value of property, plant and equipment ("PP&E") includes only assets that are associated with activities that enable the distribution of electricity ("distribution assets") and excludes non distribution assets. Working capital allowance is based on the cost of power and controllable expenses such as operations and maintenance, billing, collections and administration expenses. /C

1.1. Fixed Asset Continuity Statements

The continuity statements are filed at Exhibit 2A, Tab 1, Schedule 2. Toronto Hydro confirms that:

- the continuity statements provide year-end balance and include interest during construction, and all overheads;
- the opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base correspond to the respective balances in the fixed asset continuity statements; and
- continuity statements reconcile to calculated depreciation expenses (Exhibit 4B, Tab 1, Schedule 1) and are presented by asset account.

1.2. Working Capital Allowance ("WCA")

As can be seen in Table 1, WCA rises from $296.7 million in 2011 to $369.5 million in 2014, and then drops to $241.7 million in 2015. The main driver of the WCA increase from 2011 to 2014 is the cost of power expense. In 2015, Toronto Hydro forecasts a lower WCA due to a reduction in the allowance percentages based on the utility's latest /C /C

[1] Due to a last minute revision that could not be reflected in the Revenue Requirement Work Form (RRWF) (Exhibit 6, Tab 1, Schedule 2), the rate base value shown in the RRWF is $ 1.1M higher than the Rate Base Overview table above and the Fixed Asset Continuity statements (Exhibit 2A, Tab 1, Schedule 2). The impact on the Revenue Requirement is less than $0.1 million. /C

lead lag study conducted by Navigant Consulting Inc. Further details on WCA are provided at Exhibit2A, Tab 3 and Schedules 1 and 2.

2. RATE BASE VARIANCE ANALYSIS

2.1. 2011 OEB Approved vs. 2015 Test Year

Toronto Hydro's requested rate base for the 2015 test year is $3,246.7 million, which **/C** represents an increase of $948.5 million or 41.3 percent from the rate base amount of **/C** $2,298.2 million approved by the OEB in the utility's last rebasing application (EB-2010-0142). The average net book value ("NBV") of PP&E increased by $1,003.5 million and **/C** the WCA component of rate base decreased by approximately $55.0 million from that approved by the OEB.

2.2. 2011 OEB Approved vs. 2011 Actual

Toronto Hydro's 2011 actual rate base was $38.2 million less than the 2011 OEB-approved amount. Average NBV of PP&E in 2011 was $38.2 million higher than the OEB-approved level, primarily due to higher in-service additions than originally assumed and additional 2011 capital expenditure. Toronto Hydro's actual 2011 WCA was $21.4 million higher than OEB-approved because the cost of power expenses were $170.2 million higher than the original forecast, with most of the increase being attributable to commodity price increases.

2.3. 2011 Actual vs. 2012 Actual

Toronto Hydro's rate base increased by $176.6 million from 2011 to 2012. The net increase in average PP&E was $178.1 million. Continued investment in distribution assets contributed to this increase. WCA decreased by $1.5 million in 2012 primarily due to reduction in OM&A in 2012 compared to 2011.

2.4. 2013 Actual vs. 2012 Actual

In 2013, rate base increased by $124.1 million over 2012 levels. In 2013, the average PP&E NBV increased by $86.2 million. Continued investment in distribution assets contributed to this increase. In addition, in 2013, Toronto Hydro applied for and received approval for final disposition of its smart metering costs and investments. As a result of this decision, a total of $46.8 million in smart meter assets were transferred to rate base. The net book value of stranded meters related to the deployment of smart meters was also reclassified to regulatory assets resulting in a decrease in net assets of $17.3 million. WCA increased by $37.8 million due to cost of power expenses, which were $292.3 million higher in 2013 than the 2012, with most of the increase being attributable to commodity price increases.

2.5. 2013 Actual vs. 2014 Bridge Year

In 2014, rate base is forecasted to increase by $117.2 million. Average NBV of PP&E is **/C**
expected to increase by $102.1 million due to increased investment in the distribution **/C**
system. The level of increases in average NBV of PP&E is offset by the 2013 removal of the NBV of stranded meters related to Toronto Hydro's smart metering program. In this application, Toronto Hydro is proposing disposition of its stranded meter assets (Exhibit 2B, Tab 4, Schedule 1) and therefore has removed the amounts from the ending 2013 (opening 2014) NBV of PP&E. WCA increases by $15.1 million, primarily due to rising commodity costs.

2.6. 2014 Bridge Year vs. 2015 Test Year

In 2015 rate base is forecasted to increase by $471.1 million. Average NBV of PP&E **/C**
increases by $598.9 million, while WCA decreases by $127.8 million. The increase in **/C**
PP&E includes $372.6 million towards board approved ICM of 2013-2014 and $39.8 **/C**

million towards street lighting assets. Toronto Hydro has included ICM and street lighting in the opening balance of PP&E to capture the full year return.

3. DISTRIBUTION ASSETS

Table 2A below presents a summary of Toronto Hydro's distribution assets net of accumulated depreciation (excluding construction work-in-progress), based on the OEB's minimum reporting groups for the historical (2011 to 2013), bridge (2014), and test (2015) years.

Table 2A: Net Assets (2011-2015) – Years Ending December 31 ($ millions)

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
Gross Assets	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**
Accumulated Depreciation	(2,424.2)	(2,557.1)	(2,621.7)	(2,771.3)	(2,713.9)	(2,815.6)
Net Assets	**2,183.5**	**2,251.9**	**2,356.0**	**2,456.3**	**2,436.6**	**3,161.0**

/C

The major drivers of the changes from 2011 to 2015 include:

- Continued investment in distribution assets;
- Inclusion of OEB-approved smart meter expenditures in net assets;
- Reclassification of stranded meters from net assets to regulatory assets;
- Inclusion of 2013 and 2014 ICM eligible in-service capital expenditures;

- Adjustments to decrease net assets related to the transition from UGAAP to MIFRS; and
- Completion of the Phase 1 Copeland TS project.

As directed by the OEB in its Partial Decision and Order in EB-2012-0064, Toronto Hydro transferred Incremental Capital Module ("ICM") in-service capital additions in the year 2013 and 2014 to a regulatory asset account. For the purpose of 2015 opening rate base, Toronto Hydro has included forecasted ICM in-service assets as at the end of 2014. To illustrate, Tab 2B below provides a separate view of net assets which includes ICM in-service additions in 2013 and 2014. For more information about Toronto Hydro's ICM True-Up process proposal, please refer to Exhibit 2A, Tab 9, Schedule 1.

Table 2B: Net Assets (2011-2015) – Years Ending December 31 ($ millions) Including Eligible ICM In-Service Capital Expenditures

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.8	69.8	69.3	110.0
TS Primary Above 50	10.5	11.0	11.0	11.4	11.4	12.3
Distribution System	222.6	226.5	234.7	264.6	263.3	291.4
Poles and Wires	2,893.6	3,037.9	3,312.1	3,599.0	3,552.4	3,824.2
Line Transformers	731.7	757.4	813.3	860.2	829.6	835.5
Services and Meters	303.7	317.2	282.6	314.9	315.0	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.7	87.7	98.9
Other Distribution Assets	323.9	348.9	381.2	402.2	404.7	477.3
Contributions and Grants	(294.5)	(316.6)	(339.6)	(357.2)	(357.2)	(372.5)
Gross Assets	**4,607.8**	**4,809.0**	**5,142.9**	**5,609.5**	**5,532.9**	**5,976.5**
Accumulated Depreciation	(2,424.2)	(2,557.1)	(2,623.7)	(2,781.1)	(2,723.8)	(2,815.6)
Net Assets	**2,183.5**	**2,251.9**	**2,519.1**	**2,828.4**	**2,809.2**	**3,161.0**

/C

3.1. 2011 OEB-Approved vs. 2011 Actual

Toronto Hydro reached a settlement with intervenors in its last rebasing application in 2011 (EB-2010-0142), which resulted in the OEB approving the utility's capital expenditures for 2011 on an envelope basis.[2] Toronto Hydro therefore provides its variance analysis between 2011 OEB-approved and actual net fixed assets at a total level. 2011 OEB-approved net assets were $2,001.5 million compared to $2,183.5 million historical actual net assets. As explained in more detail below, the variance of $182.0 million of actuals over the OEB-approved amounts is attributable to higher in-service additions than originally assumed and additional capital expenditures in 2011:

- **In-Service Additions**: Consistent with previous years, the in-service amounts forecasted in the 2011 rebasing application were determined based on assumptions using historical averages. Actual in-service amounts were greater than assumed resulting in a higher value of actual ending 2011 net assets than the OEB-approved amount.
- **Additional Capital Expenditures**: 2011 capital expenditures exceeded the OEB-approved amount by $66.7 million. The related 2011 in-service amounts included unanticipated amounts related to a capital lease with Canadian Power Survey Corporation for the use of stray voltage scanning equipment, the purchase of land at 715 Milner and civil construction projects. These amounts contributed to higher actual net assets in 2011 compared to amounts approved by the OEB in Toronto Hydro's last rebasing application (EB-2010-0142).

3.2. 2011 Actual vs. 2012 Actual

As table 3 below illustrates, 2012 net assets were $2,251.9 million compared to 2011 net assets of $2,183.5 million, representing an increase of $68.4 million. Capital additions were $209.4 million and depreciation expense was $140.1 million in 2012. For more

[2] EB-2010-0142, Partial Decision and Order (July 7, 2011) at pages 2 and 3.

information, refer to the fixed asset continuity statement for 2012 UGAAP (Exhibit 2A, Tab 2, Schedule 1, Appendix A). Continued investment in distribution assets contributed to this increase. The primary driver contributing to the increase is poles and wires assets.

Table 3: 2011 Historical (CGAAP) versus 2012 Historical (UGAAP) ($ millions)

	2011 Historical CGAAP	2012 Historical UGAAP	Variance ($)	Variance (%)
Land and Buildings	61.3	63.1	1.8	2.9
TS Primary Above 50	10.5	11.0	0.5	4.6
Distribution System	222.6	226.5	4.0	1.8
Poles and Wires	2,893.6	3,037.9	144.3	5.0
Line Transformers	731.7	757.4	25.7	3.5
Services and Meters	303.7	317.2	13.5	4.4
General Plant	130.1	134.4	4.3	3.3
Equipment	180.1	178.5	(1.6)	(0.9)
IT Assets	44.6	50.5	5.9	13.2
Other Distribution Assets	323.9	348.9	25.0	7.7
Contributions and Grants	(294.5)	(316.6)	(22.1)	7.5
Gross Assets	**4,607.8**	**4,809.0**	**201.2**	**4.4**
Accumulated Depreciation	(2,424.2)	(2,557.1)	(132.8)	5.5
Net Assets	**2,183.5**	**2,251.9**	**68.4**	**3.1**

Note: Variances due to rounding may exist

3.3. 2012 Actual vs. 2013 Actual

As Table 4 below illustrates, 2013 net assets were $2,356.0 million compared to historical 2012 net assets of $2,251.9 million, representing an increase of $104.1 million or 4.6 percent. Capital additions were $381.3 million and depreciation expense was $143.1 million in 2013. For more information, refer to the fixed asset continuity statement for 2013 UGAAP (Exhibit 2A, Tab 2, Schedule 1, Appendix A). Continued investment in distribution assets contributed to this increase. The primary driver contributing to the increase is poles and wires assets. The net book value of stranded meters related to the deployment of smart meters was also reclassified to regulatory assets resulting in a decrease in net assets of $17.3 million. These reductions to net assets were offset by an increase in net assets of $46.8 million related to the OEB ruling on smart meters permitting the recovery of the utility's allowed cost of capital on smart meters since 2008.

Table 4: 2012 Historical (UGAAP) versus 2013 Historical (UGAAP) ($ millions)

	2012 Historical UGAAP	2013 Historical UGAAP	Variance ($)	Variance (%)
Land and Buildings	63.1	67.3	4.1	6.6
TS Primary Above 50	11.0	11.0	(0.0)	(0.0)
Distribution System	226.5	229.3	2.8	1.2
Poles and Wires	3,037.9	3,179.0	141.0	4.6
Line Transformers	757.4	791.9	34.5	4.6
Services and Meters	317.2	278.1	(39.2)	(12.3)
General Plant	134.4	141.6	7.2	5.4
Equipment	178.5	181.8	3.3	1.9
IT Assets	50.5	56.3	5.8	11.5
Other Distribution Assets	348.9	380.2	31.2	9.0
Contributions and Grants	(316.6)	(338.8)	(22.2)	7.0
Gross Assets	**4,809.0**	**4,977.7**	**168.7**	**3.5**
Accumulated Depreciation	(2,557.1)	(2,621.7)	(64.6)	2.5
Net Assets	**2,251.9**	**2,356.0**	**104.1**	**4.6**

Note: Variances due to rounding may exist

Table 4 above reflects a reduction in net assets by $163.1 million related to ICM in-service capital expenditures, which were transferred to a regulatory asset account, as directed by the OEB in EB-2012-0064.[4]

3.4. 2013 Actual vs. 2014 Bridge

As Table 5 below illustrates, Toronto Hydro forecasts 2014 net assets at $2,456.3 million compared to historical 2013 net assets of $2,356.0 million, representing an increase of $100.3 million or 4.3 percent. Capital additions are forecasted at $470.6 million and accumulated depreciation additions are forecasted at $158.2 million in 2014. For more information,

/C

/C

[4] EB-2012-0064, Partial Decision and Order (April 2, 2013).

refer to the fixed asset continuity statement for 2014 USGAAP (Exhibit 2A, Tab 1, Schedule 2, Appendix 2-BA). Continued investment in distribution assets contributed to this increase. The primary driver contributing to the increase is poles and wires assets. **/C**

Table 5: 2013 Historical (UGAAP) versus 2014 Bridge (UGAAP) ($ millions)

	2013 Historical UGAAP	2014 Bridge UGAAP	Variance ($)	Variance (%)
Land and Buildings	67.3	69.1	1.9	2.8
TS Primary Above 50	11.0	11.1	0.2	1.4
Distribution System	229.3	245.5	16.1	7.0
Poles and Wires	3,179.0	3,300.4	121.5	3.8
Line Transformers	791.9	810.3	18.3	2.3
Services and Meters	278.1	298.7	20.7	7.4
General Plant	141.6	167.2	25.6	18.1
Equipment	181.8	189.7	7.8	4.3
IT Assets	56.3	87.4	31.1	55.2
Other Distribution Assets	380.2	402.4	22.2	5.8
Contributions and Grants	(338.8)	(354.3)	(15.5)	4.6
Gross Assets	**4,977.7**	**5,227.6**	**249.9**	**5.0**
Accumulated Depreciation	(2,621.7)	(2,771.3)	(149.6)	5.7
Net Assets	**2,356.0**	**2,456.3**	**100.2**	**4.3**

/C

Note: Variances due to rounding may exist

Table 5 above, reflects a reduction in net assets by $214.6 million related to forecasted ICM eligible in-service capital expenditures, which were transferred to a regulatory asset account as directed by the OEB. **/C**

3.5. 2014 Bridge vs. 2015 Test Year

Toronto Hydro forecasts 2015 net assets under MFIRS at $3,161.0 million compared to forecasted 2014 net assets of $2,456.3 million under UGAAP, representing an increase of $704.7 million or 28.7 percent. The 2015 opening balance net assets are adjusted for the following items, representing $393.3 million of the total net asset increase: **/C**

- $372.6 million increase related to the addition of 2013 and 2014 ICM eligible in-service capital expenditures presented in the regulatory asset account for the duration of the IRM period. /C
- $39.8 million increase for the transfer of former street lighting assets, which as proposed in Exhibit 2A, Tab 5, Schedule 1, will have a neutral effect on the utility's test year revenue requirement;
- $19.1 million decrease related to the transition from UGAAP to MIFRS.

Table 5A: 2014 Bridge (UGAAP) versus 2015 Test (MIFRS) ($ millions)

	2014 Bridge UGAAP	2015 Test MIFRS	Variance ($)	Variance (%)
Land and Buildings	69.1	110.0	40.9	59.1
TS Primary Above 50	11.1	12.3	1.2	10.4
Distribution System	245.5	291.4	45.9	18.7
Poles and Wires	3,300.4	3,824.2	523.8	15.9
Line Transformers	810.3	835.5	25.3	3.1
Services and Meters	298.7	349.0	50.2	16.8
General Plant	167.2	153.3	(13.9)	(8.3)
Equipment	189.7	197.1	7.4	3.9
IT Assets	87.4	98.9	11.4	13.1
Other Distribution Assets	402.4	477.3	75.0	18.6
Contributions and Grants	(354.3)	(372.5)	(18.2)	5.1
Gross Assets	**5,227.6**	**5,976.5**	**749.0**	**14.3**
Accumulated Depreciation	(2,771.3)	(2,815.6)	(44.3)	1.6
Net Assets	**2,456.3**	**3,161.0**	**704.7**	**28.7**

/C

Note: Variances due to rounding may exist

Capital additions are forecasted at $539.7 million. The increase in net assets is driven by the capital investments outlined in the Distribution System Plan (Exhibit 2B, Section E). /C

Land and Buildings are expected to increase $40.9 million or 59.1 percent and TS Primary Above 50 assets are expected to increase $1.2 million or 10.4 percent. The /C /C increase in both of these major plant accounts is primarily due to the Phase 1 Copeland TS project which includes the station facility construction and installation of high voltage transmission connections. The Copeland TS project was approved by the OEB under the Toronto Hydro's 2012-2014 ICM application.[5] Refer to the Station Expansion Program (Exhibit 2B, E7.9) for additional details relating to this project.

Distribution System assets are expected to increase $45.9 million or 18.7 percent. The increase in distribution system assets is primarily due to the forecasted in-service stations switchgear projects. Municipal Station Switchgear and Transformer Switchgear work was filed and approved as part of Toronto Hydro's 2012-2014 ICM application and will continue as a program in 2015 to replace existing obsolete switchgear with a modern arc-resistant design. Refer to the Switchgear Renewal Program (Exhibit 2B, E6.13) for more information about this project. **/C**

Capital investment in poles and wires is expected to increase by $523.8 million or 15.9 percent and investment in line transformer assets are expected to increase by $25.3 million or 3.1 percent. The increase in these major plant categories is primarily attributed to the Underground Circuit Renewal (Exhibit 2B, E6.1), Overhead Circuit Renewal (Exhibit 2B, E6.4), Reactive Capital (Exhibit 2B, E6.20) and Customer Connections (Exhibit 2B, E5.2) programs. **/C**

- The Underground and Overhead Circuit Renewal programs are required to replace end of life and obsolete assets to mitigate failure and safety risks.
- The Reactive Capital program is required to restore power to customers and maintain system performance and reliability when assets fail.

[5] EB-2012-0064, Partial Decision and Order (April 2, 2013) at page 53.

- The Customer Connection program allows Toronto Hydro to satisfy its obligation to connect new customers in its service area.

Net additions to poles and wires and line transformers includes the 2013 and 2014 ICM eligible in-service capital expenditures presented in the regulatory asset account for the duration of the IRM period. Former street lighting assets are also included as part of the net addition increase to poles and wires.

Services and meter assets are expected to increase \$50.2 million or 16.8 percent. The increase in services and meter assets is primarily related to the Metering program (Exhibit 2B, E6.1), the objective of which is to ensure compliance with Measurement Canada, OEB and IESO rules and regulations. **/C**

Equipment assets are expected to increase \$7.4 million or 3.9 percent. The increase in **/C** equipment is primarily due to fleet. Refer to the Fleet and Equipment Services program **/C** (Exhibit 2B, E8.1) for additional details.

IT assets are expected to increase \$11.4 million or 13.1 percent primarily due to computer hardware equipment investment which enables Toronto Hydro to efficiently and effectively plan and execute capital and operational programs and fulfill its obligations to customers and regulatory bodies. Refer to the IT Hardware program (Exhibit 2B, E8.4) for more information.

Other distribution assets are expected to increase \$75.0 million or 18.6 percent primarily due to the in-service amount for computer software additions. For additional details related to the computer software investments refer to the IT Software program (Exhibit 2B, E8.5). **/C**

Contributions and grants are expected to increase $18.2 million or 5.1 percent related to realized contributions related to in-service assets.

The forecasted accumulated depreciation additions is $208.1 million in 2015, and **/C** includes $33.9 million of losses on derecognition of assets. For more information about Toronto Hydro's depreciation expense and derecognition losses, refer to Exhibit 4B, Tab 1, Schedules 1 and 2, respectively.

Net assets were reduced by $4.6 million related to eligible investment for the purpose of enabling the connection of a renewable energy generation facility to its distribution system. In accordance with s. 79.1 of the *Ontario Energy Board Act, 1998* and s. 2.5.2.5 of the OEB's Filing Requirements (July 17, 2013), Toronto Hydro proposes to recover the cost incurred for these investments from all provincial ratepayers. Refer to Exhibit 2A, Tab 8, Schedule 1 for more information about Toronto Hydro's proposed treatment of renewable enabling eligible investments.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - CGAAF

Year **2011**

			Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 172,691,847	$ 53,066,537	$ -	($ 3,159,693)	$ 222,598,691	($ 129,292,640)	($ 24,893,304)	$ -	$ -	($ 154,185,944)	$ 68,412,747
N/A	1805	Land	$ 7,670,263	($ 1,535)	($ 58,892)	$ -	$ 7,609,837	$ -	$ -	$ -	$ -	$ -	$ 7,609,837
1	1808	Buildings	$ 45,857,359	$ 2,530,944	($ 3,761,399)	($ 45,048)	$ 44,581,856	($ 17,441,185)	($ 1,550,177)	$ 1,151,042	$ 6,334	($ 17,833,986)	$ 26,747,870
47	1815	Transformer Station Equipment >50 kV	$ 9,869,059	$ 623,021	$ -	$ -	$ 10,492,080	($ 3,945,111)	($ 380,940)	$ -	$ -	($ 4,326,051)	$ 6,166,029
47	1820	Distribution Station Equipment <50 kV	$ 199,481,416	$ 23,105,699	$ -	$ -	$ 222,587,114	($ 88,643,689)	($ 7,083,676)	$ -	$ -	($ 95,727,365)	$ 126,859,750
47	1830	Poles, Towers & Fixtures	$ 350,090,188	$ 28,998,242	$ -	$ -	$ 379,088,430	($ 171,015,223)	($ 5,824,614)	$ -	$ -	($ 176,839,838)	$ 202,248,592
47	1835	Overhead Conductors & Devices	$ 378,085,017	$ 34,893,995	$ -	$ -	$ 412,979,013	($ 240,607,561)	($ 4,341,875)	$ -	$ -	($ 244,949,436)	$ 168,029,576
47	1840	Underground Conduit	$ 1,178,820,486	$ 134,109,241	$ -	$ -	$ 1,312,929,727	($ 588,742,455)	($ 31,948,117)	$ -	$ -	($ 620,690,572)	$ 692,239,156
47	1845	Underground Conductors & Devices	$ 722,435,297	$ 66,209,802	$ -	$ -	$ 788,645,099	($ 377,725,469)	($ 13,844,464)	$ -	$ -	($ 391,569,933)	$ 397,075,166
47	1850	Line Transformers	$ 682,649,674	$ 49,044,127	$ -	$ -	$ 731,693,800	($ 356,892,831)	($ 21,426,917)	$ -	$ -	($ 378,319,748)	$ 353,374,052
47	1855	Services (Overhead & Underground)	$ 72,596,667	$ 2,896,736	$ -	$ -	$ 75,493,402	($ 13,025,365)	($ 1,433,856)	$ -	$ -	($ 14,459,221)	$ 61,034,181
47	1860	Meters	$ 210,553,546	$ 17,674,856	$ -	$ -	$ 228,228,402	($ 115,000,783)	($ 9,162,626)	$ -	$ -	($ 124,163,409)	$ 104,064,992
N/A	1905	Land	$ 1,889,782	$ 7,261,212	$ -	$ -	$ 9,150,994	$ -	$ -	$ -	$ -	$ -	$ 9,150,994
1	1908	Buildings & Fixtures	$ 105,685,557	$ 4,619,112	$ -	$ 45,048	$ 110,349,717	($ 38,167,505)	($ 6,395,106)	$ -	($ 6,334)	($ 44,568,945)	$ 65,780,772
13	1910	Leasehold Improvements	$ 19,460,717	$ 294,610	$ -	$ -	$ 19,755,328	($ 12,768,075)	($ 5,993,705)	$ -	$ -	($ 18,761,779)	$ 993,548
8	1915	Office Furniture & Equipment	$ 16,398,277	$ 4,106,766	$ -	$ -	$ 20,505,043	($ 7,024,507)	($ 1,452,357)	$ -	$ -	($ 8,476,864)	$ 12,028,179
52	1920	Computer Equipment - Hardware	$ 40,633,537	$ 3,991,660	$ -	$ -	$ 44,625,197	($ 31,228,484)	($ 4,373,915)	$ -	$ -	($ 35,602,399)	$ 9,022,798
10	1930	Transportation Equipment	$ 73,748,754	$ 11,490,148	($ 7,257,634)	$ 34,362	$ 78,015,630	($ 43,208,343)	($ 7,074,141)	$ 7,185,827	($ 57,374)	($ 43,154,031)	$ 34,861,599
8	1935	Stores Equipment	$ 5,506,283	$ -	$ -	$ -	$ 5,506,283	($ 5,476,091)	($ 7,709)	$ -	$ -	($ 5,483,800)	$ 22,484
8	1940	Tools, Shop & Garage Equipment	$ 36,736,912	$ 2,646,528	$ -	($ 192,000)	$ 39,191,440	($ 25,431,593)	($ 1,924,584)	$ -	$ -	($ 27,356,177)	$ 11,835,262
8	1945	Measurement & Testing Equipment	$ 4,866,897	$ 13,567,209	$ -	($ 13,417,930)	$ 5,016,176	($ 4,300,071)	($ 1,086,963)	$ -	$ 958,424	($ 4,428,611)	$ 587,566
8	1955	Communications Equipment	$ 26,817,595	$ 1,368,039	$ -	$ 3,351,693	$ 31,537,327	($ 21,012,708)	($ 2,899,180)	$ -	$ -	($ 23,911,888)	$ 7,625,439
8	1960	Miscellaneous Equipment	$ 170,801	$ 197,257	$ -	$ -	$ 368,058	($ 2,911)	($ 25,285)	$ -	$ -	($ 28,196)	$ 339,863
47	1970	Load Management Controls Customer Premises	$ 15,181,181	($ 338,086)	$ -	$ -	$ 14,843,095	($ 8,630,378)	($ 1,025,729)	$ -	$ -	($ 9,656,107)	$ 5,186,988
47	1975	Load Management Controls Utility Premises	$ 554,382	$ -	$ -	$ -	$ 554,382	($ 554,382)	$ -	$ -	$ -	($ 554,382)	$ -
47	1980	System Supervisor Equipment	$ 56,427,608	$ 1,154,182	$ -	$ -	$ 57,581,790	($ 36,171,073)	($ 1,763,841)	$ -	$ -	($ 37,934,914)	$ 19,646,876
47	1995	Contributions & Grants	($ 258,098,313)	($ 36,381,079)	$ -	$ -	($ 294,479,391)	$ 53,243,868	$ 8,200,745	$ -	$ -	$ 61,444,613	($ 233,034,778)
N/A	1609	Capital Contributions Paid	$ 2,042,507	$ 12,016,399	$ -	$ -	$ 14,058,906	($ 524,244)	($ 916,010)	$ -	$ -	($ 1,440,253)	$ 12,618,653
N/A	2005	Property Under Capital Leases	$ 885,800	$ -	$ -	$ 13,383,568	$ 14,269,368	($ 350,415)	$ -	$ -	($ 901,049)	($ 1,251,464)	$ 13,017,904
							$ -					$ -	$ -
		Sub-Total	**$ 4,179,709,098**	**$ 439,145,621**	**($ 11,077,924)**	**$ -**	**$ 4,607,776,794**	**($ 2,283,939,224)**	**($ 148,628,347)**	**$ 8,336,869**	**$ -**	**($ 2,424,230,701)**	**$ 2,183,546,093**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -					$ -	$ -
		Total PP&E	**$ 4,179,709,098**	**$ 439,145,621**	**($ 11,077,924)**	**$ -**	**$ 4,607,776,794**	**($ 2,283,939,224)**	**($ 148,628,347)**	**$ 8,336,869**	**$ -**	**($ 2,424,230,701)**	**$ 2,183,546,093**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ -			$ -	
		Total							**($ 148,628,347)**				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 2,189,844)
Stores Equipment	
Net Depreciation	($ 146,438,503)

Notes:

1 The below CCA classes have been updated or added for these OEB Accounts:

CCA Class	**OEB**	**Description**	**Explanation for Change**
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
52	1920	Computer Equipment - Hardware	Class 52 (with 100% CCA rate with no half-year rule) was added to Schedule II of Income Tax Regulations on April 30, 2009 - for eligible computers acquired after January 27, 2009 and before February, 2011.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2012

			Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 222,598,691	$ 19,655,588	$ -	$ -	$ 242,254,279	($ 154,185,944)	($ 20,224,259)	$ -	$ -	($ 174,410,203)	$ 67,844,075
N/A	1805	Land	$ 7,609,837	$ -	($ 13,989)	$ -	$ 7,595,848	$ -	$ -	$ -	$ -	$ -	$ 7,595,848
1	1808	Buildings	$ 44,581,856	$ 2,314,871	($ 566,615)	$ 45,048	$ 46,375,160	($ 17,833,986)	($ 1,495,626)	$ 247,655	($ 3,983)	($ 19,085,940)	$ 27,289,220
47	1815	Transformer Station Equipment >50 kV	$ 10,492,080	$ 525,966	$ -	($ 43,688)	$ 10,974,359	($ 4,326,051)	($ 402,730)	$ -	$ -	($ 4,728,781)	$ 6,245,578
47	1820	Distribution Station Equipment <50 kV	$ 222,587,114	$ 3,874,905	$ -	$ 77,169	$ 226,539,188	($ 95,727,365)	($ 6,499,970)	$ -	$ -	($ 102,227,335)	$ 124,311,853
47	1830	Poles, Towers & Fixtures	$ 379,088,430	$ 13,535,315	$ -	$ -	$ 392,623,745	($ 176,839,838)	($ 6,469,781)	$ -	$ -	($ 183,309,619)	$ 209,314,126
47	1835	Overhead Conductors & Devices	$ 412,979,013	$ 20,008,279	$ -	$ 84,573	$ 433,071,865	($ 244,949,436)	($ 5,152,543)	$ -	$ -	($ 250,101,980)	$ 182,969,885
47	1840	Underground Conduit	$ 1,312,929,727	$ 65,155,008	$ -	($ 424,660)	$ 1,377,660,076	($ 620,690,572)	($ 32,737,980)	$ -	($ 1,119)	($ 653,429,670)	$ 724,230,405
47	1845	Underground Conductors & Devices	$ 788,645,099	$ 45,810,001	$ -	$ 134,998	$ 834,590,098	($ 391,569,933)	($ 14,554,813)	$ -	($ 1,599)	($ 406,126,346)	$ 428,463,752
47	1850	Line Transformers	$ 731,693,800	$ 25,553,462	$ -	$ 184,160	$ 757,431,422	($ 378,319,748)	($ 20,415,257)	$ -	$ 1,599	($ 398,733,406)	$ 358,698,016
47	1855	Services (Overhead & Underground)	$ 75,493,402	$ 4,880,163	$ -	$ 119,394	$ 80,492,959	($ 14,459,221)	($ 1,552,305)	$ -	$ -	($ 16,011,525)	$ 64,481,434
47	1860	Meters	$ 228,228,402	$ 8,583,433	$ -	($ 71,512)	$ 236,740,323	($ 124,163,409)	($ 9,461,636)	$ -	$ -	($ 133,625,046)	$ 103,115,277
N/A	1905	Land	$ 9,150,994	$ -	$ -	$ -	$ 9,150,994	$ -	$ -	$ -	$ -	$ -	$ 9,150,994
1	1908	Buildings & Fixtures	$ 110,349,717	$ 3,688,811	$ -	($ 45,048)	$ 113,993,480	($ 44,568,945)	($ 5,597,338)	$ -	$ 3,983	($ 50,162,300)	$ 63,831,180
13	1910	Leasehold Improvements	$ 19,755,328	$ 628,396	$ -	$ -	$ 20,383,723	($ 18,761,779)	($ 604,412)	$ -	$ -	($ 19,366,191)	$ 1,017,532
8	1915	Office Furniture & Equipment	$ 20,505,043	$ 1,213,915	$ -	$ -	$ 21,718,959	($ 8,476,864)	($ 1,695,701)	$ -	$ -	($ 10,172,565)	$ 11,546,394
50	1920	Computer Equipment - Hardware	$ 44,625,197	$ 5,897,757	$ -	($ 20,079)	$ 50,502,876	($ 35,602,399)	($ 4,401,165)	$ -	$ 418	($ 40,003,146)	$ 10,499,730
10	1930	Transportation Equipment	$ 78,015,630	$ 2,116,290	($ 7,623,507)	$ 731,156	$ 73,239,570	($ 43,154,031)	($ 7,499,760)	$ 7,039,462	($ 220,097)	($ 43,834,426)	$ 29,405,144
8	1935	Stores Equipment	$ 5,506,283	$ -	$ -	$ -	$ 5,506,283	($ 5,483,800)	($ 7,709)	$ -	$ -	($ 5,491,508)	$ 14,775
8	1940	Tools, Shop & Garage Equipment	$ 39,191,440	$ 1,104,891	$ -	$ -	$ 40,296,331	($ 27,356,177)	($ 2,006,371)	$ -	$ -	($ 29,362,549)	$ 10,933,782
8	1945	Measurement & Testing Equipment	$ 5,016,176	$ 298,172	$ -	$ -	$ 5,314,349	($ 4,428,611)	($ 2,061,676)	$ -	$ 1,916,847	($ 4,573,439)	$ 740,910
8	1955	Communications Equipment	$ 31,537,327	$ 522,839	$ -	$ 20,079	$ 32,080,245	($ 23,911,888)	($ 2,684,558)	$ -	($ 418)	($ 26,596,864)	$ 5,483,380
8	1960	Miscellaneous Equipment	$ 368,058	$ 1,043	$ -	$ -	$ 369,101	($ 28,196)	($ 36,918)	$ -	$ -	($ 65,113)	$ 303,988
47	1970	Load Management Controls Customer Premises	$ 14,843,095	$ -	$ -	$ -	$ 14,843,095	($ 9,656,107)	($ 1,082,077)	$ -	$ -	($ 10,738,184)	$ 4,104,911
47	1975	Load Management Controls Utility Premises	$ 554,382	$ -	$ -	$ -	$ 554,382	($ 554,382)	$ -	$ -	$ -	($ 554,382)	$ -
47	1980	System Supervisor Equipment	$ 57,581,790	$ 526,532	$ -	($ 19,082)	$ 58,089,239	($ 37,934,914)	($ 1,761,636)	$ -	$ -	($ 39,696,550)	$ 18,392,689
47	1995	Contributions & Grants	($ 294,479,391)	($ 22,061,046)	$ -	($ 41,353)	($ 316,581,790)	$ 61,444,613	$ 9,011,788	$ -	$ 1,119	$ 70,457,520	($ 246,124,270)
N/A	1609	Capital Contributions Paid	$ 14,058,906	$ 5,590,059	$ -	$ -	$ 19,648,965	($ 1,440,253)	($ 734,850)	$ -	$ -	($ 2,175,104)	$ 17,473,861
N/A	2005	Property Under Capital Leases	$ 14,269,368	$ -	$ -	($ 731,156)	$ 13,538,213	($ 1,251,464)	$ -	$ -	($ 1,696,751)	($ 2,948,215)	$ 10,589,998
							$ -					$ -	$ -
		Sub-Total	**$ 4,607,776,794**	**$ 209,424,649**	**($ 8,204,110)**	**$ -**	**$ 4,808,997,333**	**($ 2,424,230,701)**	**($ 140,129,282)**	**$ 7,287,117**	**$ -**	**($ 2,557,072,867)**	**$ 2,251,924,467**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*					$ -					$ -	$ -
		Total PP&E	**$ 4,607,776,794**	**$ 209,424,649**	**($ 8,204,110)**	**$ -**	**$ 4,808,997,333**	**($ 2,424,230,701)**	**($ 140,129,282)**	**$ 7,287,117**	**$ -**	**($ 2,557,072,867)**	**$ 2,251,924,467**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ -			$ -	
		Total							($ 140,129,282)				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,620,301)
Stores Equipment	
Net Depreciation	($ 138,508,981)

Notes:

1 The below CCA classes have been updated for these OEB Accounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2013

			Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 242,254,279	$ 17,872,360	$ -	$ 8,261,966	$ 268,388,604	($ 174,410,203)	($ 17,210,554)	$ -	($ 7,195,178)	($ 198,815,935)	$ 69,572,669
N/A	1805	Land	$ 7,595,848	$ -	($ 7,317)	$ -	$ 7,588,531	$ -	$ -	$ -	$ -	$ -	$ 7,588,531
1	1808	Buildings	$ 46,375,160	$ 4,942,504	($ 246,793)	($ 541,000)	$ 50,529,871	($ 19,085,940)	($ 1,866,209)	$ 37,334	$ 225,417	($ 20,689,399)	$ 29,840,472
47	1815	Transformer Station Equipment >50 kV	$ 10,974,359	$ 4,172	$ -	($ 5,874)	$ 10,972,657	($ 4,728,781)	($ 404,101)	$ -	$ 180	($ 5,132,702)	$ 5,839,955
47	1820	Distribution Station Equipment <50 kV	$ 226,539,188	$ 8,271,011	$ -	($ 5,464,410)	$ 229,345,789	($ 102,227,335)	($ 6,699,017)	$ -	$ 182,105	($ 108,744,247)	$ 120,601,543
47	1830	Poles, Towers & Fixtures	$ 392,623,745	$ 30,383,301	$ -	($ 16,170,543)	$ 406,836,503	($ 183,309,619)	($ 6,883,833)	$ -	$ 87,033	($ 190,106,418)	$ 216,730,084
47	1835	Overhead Conductors & Devices	$ 433,071,865	$ 43,696,424	$ -	($ 14,172,386)	$ 462,595,902	($ 250,101,980)	($ 5,922,635)	$ -	$ 90,213	($ 255,934,401)	$ 206,661,501
47	1840	Underground Conduit	$ 1,377,660,076	$ 100,436,340	$ -	($ 57,235,826)	$ 1,420,860,590	($ 653,429,670)	($ 34,220,426)	$ -	$ 582,669	($ 687,067,427)	$ 733,793,163
47	1845	Underground Conductors & Devices	$ 834,590,098	$ 99,691,661	$ -	($ 45,594,739)	$ 888,687,020	($ 406,126,346)	($ 16,600,725)	$ -	$ 578,583	($ 422,148,488)	$ 466,538,532
47	1850	Line Transformers	$ 757,431,422	$ 55,799,337	$ -	($ 21,304,392)	$ 791,926,367	($ 398,733,406)	($ 21,501,170)	$ -	$ 228,732	($ 420,005,844)	$ 371,920,523
47	1855	Services (Overhead & Underground)	$ 80,492,959	$ 6,704,765	$ -	($ 3,072,213)	$ 84,125,511	($ 16,011,525)	($ 1,651,822)	$ -	$ 13,170	($ 17,650,177)	$ 66,475,334
47	1860	Meters	$ 236,740,323	$ 13,604,147	$ -	($ 56,391,064)	$ 193,953,406	($ 133,625,046)	($ 9,864,020)	$ -	$ 83,356,734	($ 60,132,332)	$ 133,821,074
N/A	1905	Land	$ 9,150,994	$ -	$ -	$ -	$ 9,150,994	$ -	$ -	$ -	$ -	$ -	$ 9,150,994
1	1908	Buildings & Fixtures	$ 113,993,480	$ 7,241,269	$ -	$ -	$ 121,234,749	($ 50,162,300)	($ 5,715,814)	$ -	$ -	($ 55,878,114)	$ 65,356,634
13	1910	Leasehold Improvements	$ 20,383,723	($ 31,233)	$ -	$ -	$ 20,352,491	($ 19,366,191)	($ 284,866)	$ -	$ -	($ 19,651,057)	$ 701,434
8	1915	Office Furniture & Equipment	$ 21,718,959	$ 577,423	$ -	$ -	$ 22,296,381	($ 10,172,565)	($ 2,321,386)	$ -	$ -	($ 12,493,951)	$ 9,802,431
50	1920	Computer Equipment - Hardware	$ 50,502,876	$ 5,275,147	$ -	$ 550,474	$ 56,328,497	($ 40,003,146)	($ 4,595,199)	$ -	($ 537,522)	($ 45,135,867)	$ 11,192,631
10	1930	Transportation Equipment	$ 73,239,570	$ 337,366	($ 832,365)	$ 120,283	$ 72,864,854	($ 43,834,426)	($ 7,148,702)	$ 773,987	($ 72,944)	($ 50,282,085)	$ 22,582,769
8	1935	Stores Equipment	$ 5,506,283	$ -	$ -	$ -	$ 5,506,283	($ 5,491,508)	($ 7,709)	$ -	$ -	($ 5,499,217)	$ 7,066
8	1940	Tools, Shop & Garage Equipment	$ 40,296,331	$ 2,291,332	$ -	$ -	$ 42,587,663	($ 29,362,549)	($ 2,188,127)	$ -	$ -	($ 31,550,676)	$ 11,036,987
8	1945	Measurement & Testing Equipment	$ 5,314,349	$ 304,913	($ 194,000)	($ 304,913)	$ 5,120,349	($ 4,573,439)	($ 2,081,814)	$ 54,843	$ 1,960,406	($ 4,640,005)	$ 480,344
8	1955	Communications Equipment	$ 32,080,245	$ 1,011,467	$ -	$ -	$ 33,091,712	($ 26,596,864)	($ 1,901,560)	$ -	$ -	($ 28,498,424)	$ 4,593,288
8	1960	Miscellaneous Equipment	$ 369,101	$ -	$ -	$ -	$ 369,101	($ 65,113)	($ 36,918)	$ -	$ -	($ 102,031)	$ 267,071
47	1970	Load Management Controls Customer Premises	$ 14,843,095	$ -	$ -	$ -	$ 14,843,095	($ 10,738,184)	($ 1,082,077)	$ -	$ -	($ 11,820,262)	$ 3,022,834
47	1975	Load Management Controls Utility Premises	$ 554,382	$ -	$ -	$ -	$ 554,382	($ 554,382)	$ -	$ -	$ -	($ 554,382)	$ -
47	1980	System Supervisor Equipment	$ 58,089,239	$ 3,405,676	$ -	($ 1,013,175)	$ 60,481,740	($ 39,696,550)	($ 1,814,662)	$ -	$ 14,286	($ 41,496,926)	$ 18,984,815
47	1995	Contributions & Grants	($ 316,581,790)	($ 23,083,937)	$ -	$ 858,765	($ 338,806,962)	$ 70,457,520	$ 9,836,203	$ -	($ 13,004)	$ 80,280,719	($ 258,526,243)
N/A	1609	Capital Contributions Paid	$ 19,648,965	$ 2,532,156	$ -	$ -	$ 22,181,121	($ 2,175,104)	($ 901,706)	$ -	$ -	($ 3,076,809)	$ 19,104,312
N/A	2005	Property Under Capital Leases	$ 13,538,213	$ -	$ -	$ 184,630	$ 13,722,843	($ 2,948,215)	$ -	$ -	($ 1,887,462)	($ 4,835,677)	$ 8,887,166
							$ -					$ -	$ -
		Sub-Total	**$ 4,808,997,333**	**$ 381,267,602**	**($ 1,280,474)**	**($ 211,294,417)**	**$ 4,977,690,044**	**($ 2,557,072,867)**	**($ 143,068,846)**	**$ 866,164**	**$ 77,613,418**	**($ 2,621,662,131)**	**$ 2,356,027,913**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*					$ -					$ -	$ -
		Total PP&E	**$ 4,808,997,333**	**$ 381,267,602**	**($ 1,280,474)**	**($ 211,294,417)**	**$ 4,977,690,044**	**($ 2,557,072,867)**	**($ 143,068,846)**	**$ 866,164**	**$ 77,613,418**	**($ 2,621,662,131)**	**$ 2,356,027,913**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ -			$ -	
		Total							($ 143,068,846)				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 2,314,931)
Stores Equipment	
Net Depreciation	($ 140,753,915)

Notes:

1 The below CCA classes have been updated for these OEB Accounts

CCA Class	**OEB**	**Description**	**Explanation for Change**
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - UGAAP

Year 2014

			Cost					Accumulated Depreciation					
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 268,388,604	$ 15,168,023	$ -	($ 330,435)	$ 283,226,192	($ 198,815,935)	($ 19,182,023)	$ -	$ 17,128	($ 217,980,830)	$ 65,245,361
N/A	1805	Land	$ 7,588,531	$ -	($ 3,288)	$ -	$ 7,585,243	$ -	$ -	$ -	$ -	$ -	$ 7,585,243
1	1808	Buildings	$ 50,529,871	$ 4,340,259	($ 2,379,439)	($ 78,322)	$ 52,412,370	($ 20,689,399)	($ 2,023,489)	$ 381,380	$ 316,955	($ 22,014,552)	$ 30,397,818
47	1815	Transformer Station Equipment >50 kV	$ 10,972,657	$ 473,723	$ -	($ 321,055)	$ 11,125,325	($ 5,132,702)	($ 410,092)	$ -	$ 3,623	($ 5,539,171)	$ 5,586,154
47	1820	Distribution Station Equipment <50 kV	$ 229,345,789	$ 29,848,866	$ -	($ 13,711,927)	$ 245,482,729	($ 108,744,247)	($ 7,040,253)	$ -	$ 342,531	($ 115,441,968)	$ 130,040,760
47	1830	Poles, Towers & Fixtures	$ 406,836,503	$ 36,083,610	($ 1,575,844)	($ 26,984,374)	$ 414,359,894	($ 190,106,418)	($ 7,596,852)	$ 421,813	$ 603,230	($ 196,678,227)	$ 217,681,668
47	1835	Overhead Conductors & Devices	$ 462,595,902	$ 49,556,844	$ -	($ 25,230,128)	$ 486,922,618	($ 255,934,401)	($ 6,901,315)	$ -	$ 518,672	($ 262,317,044)	$ 224,605,574
47	1840	Underground Conduit	$ 1,420,860,590	$ 143,831,357	$ -	($ 84,834,206)	$ 1,479,857,741	($ 687,067,427)	($ 36,940,621)	$ -	$ 2,658,269	($ 721,349,779)	$ 758,507,962
47	1845	Underground Conductors & Devices	$ 888,687,020	$ 58,960,887	$ -	($ 28,340,892)	$ 919,307,016	($ 422,148,488)	($ 17,590,134)	$ -	$ 1,777,485	($ 437,961,137)	$ 481,345,879
47	1850	Line Transformers	$ 791,926,367	$ 46,968,875	$ -	($ 28,636,422)	$ 810,258,820	($ 420,005,844)	($ 22,171,293)	$ -	$ 1,181,371	($ 440,995,767)	$ 369,263,053
47	1855	Services (Overhead & Underground)	$ 84,125,511	$ 17,455,197	$ -	($ 9,502,810)	$ 92,077,897	($ 17,650,177)	($ 1,874,227)	$ -	$ 154,401	($ 19,370,003)	$ 72,707,894
47	1860	Meters	$ 193,953,406	$ 14,882,921	$ -	($ 2,182,077)	$ 206,654,251	($ 60,132,332)	($ 12,464,057)	$ -	$ 139,433	($ 72,456,955)	$ 134,197,295
N/A	1905	Land	$ 9,150,994	$ -	$ -	$ -	$ 9,150,994	$ -	$ -	$ -	$ -	$ -	$ 9,150,994
1	1908	Buildings & Fixtures	$ 121,234,749	$ 25,218,362	$ -	$ 3,515	$ 146,456,626	($ 55,878,114)	($ 6,377,509)	$ -	$ 143	($ 62,255,481)	$ 84,201,145
13	1910	Leasehold Improvements	$ 20,352,491	$ 387,591	$ -	$ -	$ 20,740,081	($ 19,651,057)	($ 314,340)	$ -	$ -	($ 19,965,397)	$ 774,685
8	1915	Office Furniture & Equipment	$ 22,296,381	$ 2,347,858	$ -	$ -	$ 24,644,239	($ 12,493,951)	($ 2,128,106)	$ -	$ -	($ 14,622,057)	$ 10,022,182
50	1920	Computer Equipment - Hardware	$ 56,328,497	$ 31,340,289	$ -	($ 252,540)	$ 87,416,246	($ 45,135,867)	($ 7,028,006)	$ -	$ 16,303	($ 52,147,569)	$ 35,268,677
10	1930	Transportation Equipment	$ 72,864,854	$ 4,223,323	$ -	($ 1,307)	$ 77,086,870	($ 50,282,085)	($ 6,558,032)	$ -	$ 218	($ 56,839,900)	$ 20,246,970
8	1935	Stores Equipment	$ 5,506,283	$ -	$ -	$ -	$ 5,506,283	($ 5,499,217)	($ 7,066)	$ -	$ -	($ 5,506,283)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 42,587,663	$ 472,026	$ -	$ -	$ 43,059,688	($ 31,550,676)	($ 2,216,738)	$ -	$ -	($ 33,767,414)	$ 9,292,274
8	1945	Measurement & Testing Equipment	$ 5,120,349	$ 2,101,186	$ -	($ 2,092,578)	$ 5,128,956	($ 4,640,005)	($ 3,744,776)	$ -	$ 3,744,029	($ 4,640,751)	$ 488,205
8	1955	Communications Equipment	$ 33,091,712	$ 773,912	$ -	$ -	$ 33,865,625	($ 28,498,424)	($ 1,855,881)	$ -	$ -	($ 30,354,306)	$ 3,511,319
8	1960	Miscellaneous Equipment	$ 369,101	$ -	$ -	$ -	$ 369,101	($ 102,031)	($ 36,918)	$ -	$ -	($ 138,948)	$ 230,153
47	1970	Load Management Controls Customer Premises	$ 14,843,095	$ -	$ -	$ -	$ 14,843,095	($ 11,820,262)	($ 1,082,077)	$ -	$ -	($ 12,902,339)	$ 1,940,757
47	1975	Load Management Controls Utility Premises	$ 554,382	$ -	$ -	$ -	$ 554,382	($ 554,382)	$ -	$ -	$ -	($ 554,382)	$ -
47	1980	System Supervisor Equipment	$ 60,481,740	$ 1,924,300	$ -	($ 215,829)	$ 62,190,211	($ 41,496,926)	($ 2,048,691)	$ -	$ 72,158	($ 43,473,459)	$ 18,716,753
47	1995	Contributions & Grants	($ 338,806,962)	($ 17,584,653)	$ -	$ 2,123,873	($ 354,267,741)	$ 80,280,719	$ 10,351,884	$ -	($ 18,199)	$ 90,614,404	($ 263,653,337)
N/A	1609	Capital Contributions Paid	$ 22,181,121	$ 1,798,200	$ -	$ 1,761,108	$ 25,740,429	($ 3,076,809)	($ 955,031)	$ -	($ 36,296)	($ 4,068,136)	$ 21,672,292
N/A	2005	Property Under Capital Leases	$ 13,722,843	$ -	$ -	$ 2,092,578	$ 15,815,421	($ 4,835,677)	$ -	$ -	($ 3,744,029)	($ 8,579,706)	$ 7,235,715
				$ -		$ -	$ -		$ -		$ -		
		Sub-Total	**$ 4,977,690,044**	**$ 470,572,957**	**($ 3,958,571)**	**($ 216,733,828)**	**$ 5,227,570,601**	**($ 2,621,662,131)**	**($ 158,195,645)**	**$ 803,193**	**$ 7,747,425**	**($ 2,771,307,158)**	**$ 2,456,263,443**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -					$ -	$ -
		***Less Other Non Rate-Regulated Utility Assets** (input as negative)*					$ -					$ -	$ -
		Total PP&E	**$ 4,977,690,044**	**$ 470,572,957**	**($ 3,958,571)**	**($ 216,733,828)**	**$ 5,227,570,601**	**($ 2,621,662,131)**	**($ 158,195,645)**	**$ 803,193**	**$ 7,747,425**	**($ 2,771,307,158)**	**$ 2,456,263,443**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)							$ -			$ -	
		Total							($ 158,195,645)				

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 2,342,979)
Stores Equipment	
Net Depreciation	($ 155,852,666)

Notes:

1 The below CCA classes has been updated or added for these OEB Accounts:

CCA Class	**OEB**	**Description**	**Explanation for Change**
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures [“ECE”] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures [“ECE”] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Retirement	Cost: Transfers	Cost: Derecognition	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Retirement	Accumulated Depreciation: Transfers	Accumulated Depreciation: Derecognition	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 268,388,604	$ 15,177,636	$ -	($ 331,236)	$ -	$ 283,235,005	($ 198,815,935)	($ 19,182,937)	$ -	$ 17,170	$ -	($ 217,981,703)	$ 65,253,302
N/A	1612	Land Rights	$ 7,191,090	$ -	$ -	$ -	$ -	$ 7,191,090	$ -	($ 89,423)	$ -	$ -	$ -	($ 89,423)	$ 7,101,667
N/A	1805	Land	$ 7,588,531	$ -	($ 3,288)	$ -	$ -	$ 7,585,243	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,585,243
1	1808	Buildings	$ 50,051,442	$ 4,342,809	($ 2,379,439)	($ 80,876)	$ -	$ 51,933,935	($ 20,689,399)	($ 2,034,879)	$ 381,380	$ 316,976	$ -	($ 22,025,922)	$ 29,908,013
47	1815	Transformer Station Equipment >50 kV	$ 10,972,657	$ 474,187	$ -	($ 321,661)	$ -	$ 11,125,183	($ 5,132,702)	($ 410,099)	$ -	$ 3,630	$ -	($ 5,539,171)	$ 5,586,012
47	1820	Distribution Station Equipment <50 kV	$ 229,345,789	$ 29,862,940	$ -	($ 13,738,605)	($ 1,289,203)	$ 244,180,921	($ 108,744,247)	($ 7,040,476)	$ -	$ 342,783	$ 1,211,150	($ 114,230,790)	$ 129,950,132
47	1830	Poles, Towers & Fixtures	$ 406,937,426	$ 36,102,639	($ 1,575,844)	($ 27,039,814)	($ 19,700,692)	$ 394,723,714	($ 190,106,418)	($ 7,597,440)	$ 421,813	$ 603,611	$ 10,481,739	($ 186,196,694)	$ 208,527,020
47	1835	Overhead Conductors & Devices	$ 462,595,902	$ 49,585,933	$ -	($ 25,282,689)	($ 5,667,212)	$ 481,231,934	($ 255,934,401)	($ 6,906,901)	$ -	$ 519,020	$ 3,244,682	($ 259,077,600)	$ 222,154,334
47	1840	Underground Conduit	$ 1,420,860,590	$ 143,930,570	$ -	($ 85,058,238)	($ 744,800)	$ 1,478,988,122	($ 687,067,427)	($ 36,952,150)	$ -	$ 2,660,137	$ 419,968	($ 720,939,472)	$ 758,048,650
47	1845	Underground Conductors & Devices	$ 888,938,892	$ 59,003,468	$ -	($ 28,397,701)	($ 20,974,613)	$ 898,570,047	($ 422,148,488)	($ 17,441,988)	$ -	$ 1,777,944	$ 17,708,268	($ 420,104,264)	$ 478,465,783
47	1850	Line Transformers	$ 791,192,942	$ 47,004,173	$ -	($ 28,690,543)	($ 29,945,614)	$ 779,560,959	($ 420,005,844)	($ 22,237,759)	$ -	$ 1,181,907	$ 20,438,401	($ 420,623,295)	$ 358,937,664
47	1855	Services (Overhead & Underground)	$ 84,125,511	$ 17,465,910	$ -	($ 9,521,934)	$ -	$ 92,069,487	($ 17,650,177)	($ 1,874,323)	$ -	$ 154,539	$ -	($ 19,369,961)	$ 72,699,526
47	1860	Meters	$ 193,953,406	$ 14,890,821	$ -	($ 2,186,247)	$ -	$ 206,657,980	($ 60,132,332)	($ 12,464,374)	$ -	$ 139,514	$ -	($ 72,457,191)	$ 134,200,789
N/A	1905	Land	$ 9,150,994	$ -	$ -	$ -	$ -	$ 9,150,994	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,150,994
1	1908	Buildings & Fixtures	$ 121,234,749	$ 25,218,671	$ -	$ 3,506	($ 125,000)	$ 146,331,925	($ 55,878,114)	($ 6,377,517)	$ -	$ 143	$ 112,500	($ 62,142,988)	$ 84,188,937
13	1910	Leasehold Improvements	$ 20,352,491	$ 387,591	$ -	$ -	$ -	$ 20,740,081	($ 19,651,057)	($ 314,340)	$ -	$ -	$ -	($ 19,965,397)	$ 774,685
8	1915	Office Furniture & Equipment	$ 22,296,381	$ 2,347,871	$ -	$ -	($ 3,842)	$ 24,640,411	($ 12,493,951)	($ 2,128,107)	$ -	$ -	$ 3,485	($ 14,618,572)	$ 10,021,839
50	1920	Computer Equipment - Hardware	$ 56,328,497	$ 31,345,390	$ -	($ 253,152)	$ -	$ 87,420,735	($ 45,135,867)	($ 7,028,569)	$ -	$ 16,343	$ -	($ 52,148,093)	$ 35,272,642
10	1930	Transportation Equipment	$ 72,864,854	$ 4,225,151	$ -	($ 1,307)	$ -	$ 77,088,698	($ 50,282,085)	($ 6,558,138)	$ -	$ 218	$ -	($ 56,840,005)	$ 20,248,692
8	1935	Stores Equipment	$ 5,506,283	$ -	$ -	$ -	$ -	$ 5,506,283	($ 5,499,217)	($ 7,066)	$ -	$ -	$ -	($ 5,506,283)	$ -
8	1940	Tools, Shop & Garage Equipment	$ 42,587,663	$ 472,378	$ -	$ -	$ -	$ 43,060,041	($ 31,550,676)	($ 2,216,753)	$ -	$ -	$ -	($ 33,767,429)	$ 9,292,612
8	1945	Measurement & Testing Equipment	$ 5,120,349	$ 2,101,189	$ -	($ 2,092,578)	$ -	$ 5,128,960	($ 4,640,005)	($ 3,744,776)	$ -	$ 3,744,029	$ -	($ 4,640,751)	$ 488,208
8	1955	Communications Equipment	$ 33,091,712	$ 773,912	$ -	$ -	$ -	$ 33,865,625	($ 28,498,424)	($ 1,855,881)	$ -	$ -	$ -	($ 30,354,306)	$ 3,511,319
8	1960	Miscellaneous Equipment	$ 369,101	$ -	$ -	$ -	$ -	$ 369,101	($ 102,031)	($ 36,918)	$ -	$ -	$ -	($ 138,948)	$ 230,153
47	1970	Load Management Controls Customer Premises	$ 14,843,095	$ -	$ -	$ -	$ -	$ 14,843,095	($ 11,820,262)	($ 1,082,077)	$ -	$ -	$ -	($ 12,902,339)	$ 1,940,757
47	1975	Load Management Controls Utility Premises	$ 554,382	$ -	$ -	$ -	$ -	$ 554,382	($ 554,382)	$ -	$ -	$ -	$ -	($ 554,382)	$ -
47	1980	System Supervisor Equipment	$ 60,481,740	$ 1,925,700	$ -	($ 216,297)	($ 4,680,597)	$ 57,510,547	($ 41,496,926)	($ 2,048,748)	$ -	$ 72,168	$ 3,775,638	($ 39,697,869)	$ 17,812,678
47	1995	Contributions & Grants	($ 338,806,962)	($ 17,605,144)	$ -	$ 2,129,381	$ -	($ 354,282,725)	$ 80,280,719	$ 10,369,809	$ -	($ 18,239)	$ -	$ 90,632,289	($ 263,650,436)
N/A	1609	Capital Contributions Paid	$ 22,181,121	$ 1,803,632	$ -	$ 1,761,108	$ -	$ 25,745,861	($ 3,076,809)	($ 955,180)	$ -	($ 36,296)	$ -	($ 4,068,286)	$ 21,677,575
N/A	2005	Property Under Capital Leases	$ 13,722,843	$ -	$ -	$ 2,092,578	$ -	$ 15,815,421	($ 4,835,677)	$ -	$ -	($ 3,744,029)	$ -	($ 8,579,706)	$ 7,235,715
				$ -		$ -		$ -		$ -		$ -			
		Sub-Total	**$ 4,984,022,075**	**$ 470,837,428**	**($ 3,958,571)**	**($ 217,226,307)**	**($ 83,131,571)**	**$ 5,150,543,054**	**($ 2,621,662,131)**	**($ 158,217,010)**	**$ 803,193**	**$ 7,751,568**	**$ 57,395,830**	**($ 2,713,928,550)**	**$ 2,436,614,504**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*						$ -						$ -	$ -
		Total PP&E	**$ 4,984,022,075**	**$ 470,837,428**	**($ 3,958,571)**	**($ 217,226,307)**	**($ 83,131,571)**	**$ 5,150,543,054**	**($ 2,621,662,131)**	**($ 158,217,010)**	**$ 803,193**	**$ 7,751,568**	**$ 57,395,830**	**($ 2,713,928,550)**	**$ 2,436,614,504**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)								$ -				$ -	
		Total								**($ 158,217,010)**					

CCA Class	OEB	Description
10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 2,342,979)
Stores Equipment	
Net Depreciation	($ 155,874,031)

Notes:

1 The below CCA classes has been updated or added for these OEB Accounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included in Class 52.
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

OEB Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2015

CCA Class	OEB	Description	Cost: Original Opening Balance	STL Transfer	ICM Transfer	Revised Opening Balance	Additions	Retirement	Transfers	Derecognition	Closing Balance
12	1611	Computer Software (Formally known as Account 1925)	$ 283,235,005	$ -	$ 331,236	$ 283,566,240	$ 25,707,753	$ -	$ -	$ -	$ 309,273,993
N/A	1612	Land Rights	$ 7,191,090	$ -	$ -	$ 7,191,090	$ -	$ -	$ -	$ -	$ 7,191,090
N/A	1805	Land	$ 7,585,243	$ -	$ -	$ 7,585,243	$ -	$ -	$ -	$ -	$ 7,585,243
1	1808	Buildings	$ 51,933,935	$ -	$ 621,876	$ 52,555,812	$ 42,675,695	($ 1,449,701)	$ -	$ -	$ 93,781,805
47	1815	Transformer Station Equipment >50 kV	$ 11,125,183	$ -	$ 321,661	$ 11,446,844	$ 928,991	$ -	$ -	($ 94,141)	$ 12,281,694
47	1820	Distribution Station Equipment <50 kV	$ 244,180,921	$ -	$ 19,117,868	$ 263,298,789	$ 30,196,781	$ -	($ 470,712)	($ 1,630,381)	$ 291,394,477
47	1830	Poles, Towers & Fixtures	$ 394,723,714	$ 36,121,302	$ 43,211,408	$ 474,056,425	$ 42,285,278	$ -	$ 0	($ 27,184,232)	$ 489,157,471
47	1835	Overhead Conductors & Devices	$ 481,231,934	$ 341,869	$ 39,460,264	$ 521,034,068	$ 50,220,187	$ -	$ -	($ 14,001,761)	$ 557,252,494
47	1840	Underground Conduit	$ 1,478,988,122	$ 3,457,400	$ 142,264,440	$ 1,624,709,962	$ 124,467,391	$ -	$ -	$ -	$ 1,749,177,353
47	1845	Underground Conductors & Devices	$ 898,570,047	$ 4,697,187	$ 73,974,813	$ 977,242,048	$ 70,084,398	$ -	($ 0)	($ 18,693,747)	$ 1,028,632,698
47	1850	Line Transformers	$ 779,560,959	$ -	$ 50,042,828	$ 829,603,786	$ 36,538,578	$ -	$ 0	($ 30,603,146)	$ 835,539,218
47	1855	Services (Overhead & Underground)	$ 92,069,487	$ -	$ 12,595,308	$ 104,664,795	$ 15,347,254	$ -	$ -	($ 7,152)	$ 120,004,896
47	1860	Meters	$ 206,657,980	$ -	$ 3,644,325	$ 210,302,305	$ 19,717,726	$ -	$ 0	($ 1,071,386)	$ 228,948,645
N/A	1905	Land	$ 9,150,994	$ -	$ -	$ 9,150,994	$ -	($ 477,212)	$ -	$ -	$ 8,673,782
1	1908	Buildings & Fixtures	$ 146,331,925	$ -	($ 3,506)	$ 146,328,420	$ 17,921,294	($ 30,471,343)	$ -	($ 1,287,428)	$ 132,490,943
13	1910	Leasehold Improvements	$ 20,740,081	$ -	$ -	$ 20,740,081	$ 43,066	$ -	$ -	$ -	$ 20,783,147
8	1915	Office Furniture & Equipment	$ 24,640,411	$ -	$ -	$ 24,640,411	$ 210,700	$ -	$ -	($ 63,647)	$ 24,787,464
50	1920	Computer Equipment - Hardware	$ 87,420,735	$ -	$ 253,152	$ 87,673,888	$ 11,191,364	$ -	$ -	$ -	$ 98,865,251
10	1930	Transportation Equipment	$ 77,088,698	$ -	$ 1,307	$ 77,090,005	$ 3,877,748	$ -	$ -	$ -	$ 80,967,753
8	1935	Stores Equipment	$ 5,506,283	$ -	$ -	$ 5,506,283	$ -	$ -	$ -	$ -	$ 5,506,283
8	1940	Tools, Shop & Garage Equipment	$ 43,060,041	$ -	$ -	$ 43,060,041	$ 1,832,094	$ -	$ -	$ -	$ 44,892,135
8	1945	Measurement & Testing Equipment	$ 5,128,960	$ -	$ -	$ 5,128,960	$ -	$ -	($ 0)	$ -	$ 5,128,960
8	1955	Communications Equipment	$ 33,865,625	$ -	$ -	$ 33,865,625	$ 1,571,175	$ -	$ -	$ -	$ 35,436,800
8	1960	Miscellaneous Equipment	$ 369,101	$ -	$ -	$ 369,101	$ 7,831	$ -	$ -	$ -	$ 376,932
47	1970	Load Management Controls Customer Premises	$ 14,843,095	$ -	$ -	$ 14,843,095	$ 99,273	$ -	$ -	$ -	$ 14,942,368
47	1975	Load Management Controls Utility Premises	$ 554,382	$ -	$ -	$ 554,382	$ -	$ -	$ -	$ -	$ 554,382
47	1980	System Supervisor Equipment	$ 57,510,547	$ -	$ 1,229,472	$ 58,740,019	$ 7,707,664	$ -	($ 4,096,668)	($ 7,296,713)	$ 55,054,301
47	1995	Contributions & Grants	($ 354,282,725)	$ -	($ 2,902,453)	($ 357,185,178)	($ 15,280,038)	$ -	($ 0)	$ -	($ 372,465,216)
N/A	1609	Capital Contributions Paid	$ 25,745,861	$ -	($ 1,761,108)	$ 23,984,753	$ 52,373,679	$ -	($ 1,853,428)	$ -	$ 74,505,004
N/A	2005	Property Under Capital Leases	$ 15,815,421	$ -		$ 15,815,421	$ -	$ -	$ 0	$ -	$ 15,815,421
		Sub-Total	**$ 5,150,543,054**	**$ 44,617,759**	**$ 382,402,893**	**$ 5,577,563,706**	**$ 539,725,880**	**($ 32,398,256)**	**($ 6,420,808)**	**($ 101,933,734)**	**$ 5,976,536,788**
		Less Socialized Renewable Energy Generation Investments (input as negative)									$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*									$ -
		Total PP&E	**$ 5,150,543,054**	**$ 44,617,759**	**$ 382,402,893**	**$ 5,577,563,706**	**$ 539,725,880**	**($ 32,398,256)**	**($ 6,420,808)**	**($ 101,933,734)**	**$ 5,976,536,788**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total									

10		Transportation
8		Stores Equipment

Notes:

1 The below CCA classes has been updated or added for these OEB Accounts:

CCA Class	OEB	Description	Explanation for Change
N/A	1612	Land Rights	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1808	Buildings	For tax purposes, the land rights/easements are treated as eligible capital expenditures ["ECE"] and are recorded in Schedule 10 of the income tax return (per paragraph 29 of Interpretation Bulletin IT-143R3)
1	1908	Buildings & Fixtures	Per definition of CCA Class 1 in Schedule II of Income Tax Regulations
50	1920	Computer Equipment - Hardware	Class 50 (with 55% CCA rate and subject to half-year rule) was added to Schedule II of Income Tax Regulations on April 23, 2009 - for eligible computers and software acquired after March 18, 2007, but not including property that is included i
N/A	1609	Capital Contributions Paid	For tax purposes, the capital contributions paid are treated as ECE and are recorded in Schedule 10 of the income tax return (per paragraph 30 of Interpretation Bulletin IT-143R3)
N/A	2005	Property Under Capital Leases	Not Capitalized for tax purposes, actual payment in the year is deductible for tax.

			Accumulated Depreciation									
CCA Class	**OEB**	**Description**	**Original Opening Balance**	**STL Transfer**	**ICM Transfer**	**Revised Opening Balance**	**Additions**	**Retirement**	**Transfers**	**Derecognition**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	($ 217,981,703)	$ -	($ 17,170)	($ 217,998,872)	($ 21,011,750)	$ -	$ -	$ -	($ 239,010,622)	$ 70,263,371
N/A	1612	Land Rights	($ 89,423)	$ -	$ -	($ 89,423)	($ 89,423)	$ -	$ -	$ -	($ 178,846)	$ 7,012,244
N/A	1805	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,585,243
1	1808	Buildings	($ 22,025,922)	$ -	($ 542,392)	($ 22,568,314)	($ 2,164,056)	$ 130,522	$ 0	$ -	($ 24,601,849)	$ 69,179,957
47	1815	Transformer Station Equipment >50 kV	($ 5,539,171)	$ -	($ 3,630)	($ 5,542,801)	($ 433,082)	$ -	$ 3	$ 55,292	($ 5,920,589)	$ 6,361,105
47	1820	Distribution Station Equipment <50 kV	($ 114,230,790)	$ -	($ 522,081)	($ 114,752,870)	($ 8,071,762)	$ -	$ 4,124	$ 1,547,522	($ 121,272,987)	$ 170,121,490
47	1830	Poles, Towers & Fixtures	($ 186,196,694)	($ 3,536,803)	($ 690,647)	($ 190,424,144)	($ 9,383,299)	$ -	$ 1,211	$ 14,391,300	($ 185,414,933)	$ 303,742,539
47	1835	Overhead Conductors & Devices	($ 259,077,600)	($ 25,769)	($ 609,398)	($ 259,712,767)	($ 8,010,517)	$ -	$ 2,508	$ 11,597,279	($ 256,123,497)	$ 301,128,997
47	1840	Underground Conduit	($ 720,939,472)	($ 273,033)	($ 3,242,546)	($ 724,455,051)	($ 40,909,577)	$ -	$ 28,132	$ -	($ 765,336,496)	$ 983,840,857
47	1845	Underground Conductors & Devices	($ 420,104,264)	($ 976,046)	($ 2,357,313)	($ 423,437,622)	($ 18,874,495)	$ -	$ 8,037	$ 12,366,339	($ 429,937,742)	$ 598,694,956
47	1850	Line Transformers	($ 420,623,295)	$ -	($ 1,434,826)	($ 422,058,121)	($ 22,574,248)	$ -	$ 1,019	$ 20,848,109	($ 423,783,240)	$ 411,755,978
47	1855	Services (Overhead & Underground)	($ 19,369,961)	$ -	($ 167,709)	($ 19,537,670)	($ 2,235,152)	$ -	$ 169	$ 6,706	($ 21,765,946)	$ 98,238,950
47	1860	Meters	($ 72,457,191)	$ -	($ 198,422)	($ 72,655,613)	($ 13,258,376)	$ -	$ 1	$ 524,830	($ 85,389,159)	$ 143,559,487
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,673,782
1	1908	Buildings & Fixtures	($ 62,142,988)	$ -	($ 143)	($ 62,143,131)	($ 6,162,152)	$ 18,990,375	$ 0	$ 691,012	($ 48,623,896)	$ 83,867,047
13	1910	Leasehold Improvements	($ 19,965,397)	$ -	$ -	($ 19,965,397)	($ 305,716)	$ -	$ -	$ -	($ 20,271,113)	$ 512,034
8	1915	Office Furniture & Equipment	($ 14,618,572)	$ -	$ -	($ 14,618,572)	($ 1,988,900)	$ -	$ -	$ 51,630	($ 16,555,842)	$ 8,231,621
50	1920	Computer Equipment - Hardware	($ 52,148,093)	$ -	($ 16,343)	($ 52,164,436)	($ 12,430,692)	$ -	$ -	$ -	($ 64,595,128)	$ 34,270,123
10	1930	Transportation Equipment	($ 56,840,005)	$ -	($ 218)	($ 56,840,223)	($ 6,376,745)	$ -	$ -	$ -	($ 63,216,968)	$ 17,750,785
8	1935	Stores Equipment	($ 5,506,283)	$ -	$ -	($ 5,506,283)	$ -	$ -	$ -	$ -	($ 5,506,283)	$ -
8	1940	Tools, Shop & Garage Equipment	($ 33,767,429)	$ -	$ -	($ 33,767,429)	($ 2,220,076)	$ -	$ -	$ -	($ 35,987,505)	$ 8,904,630
8	1945	Measurement & Testing Equipment	($ 4,640,751)	$ -	$ -	($ 4,640,751)	($ 2,218,623)	$ -	$ 2,222,154	$ -	($ 4,637,220)	$ 491,739
8	1955	Communications Equipment	($ 30,354,306)	$ -	$ -	($ 30,354,306)	($ 1,924,002)	$ -	$ -	$ -	($ 32,278,308)	$ 3,158,491
8	1960	Miscellaneous Equipment	($ 138,948)	$ -	$ -	($ 138,948)	($ 37,146)	$ -	$ -	$ -	($ 176,094)	$ 200,838
47	1970	Load Management Controls Customer Premises	($ 12,902,339)	$ -	$ -	($ 12,902,339)	($ 1,070,206)	$ -	$ -	$ -	($ 13,972,544)	$ 969,824
47	1975	Load Management Controls Utility Premises	($ 554,382)	$ -	$ -	($ 554,382)	$ -	$ -	$ -	$ -	($ 554,382)	$ -
47	1980	System Supervisor Equipment	($ 39,697,869)	$ -	($ 86,454)	($ 39,784,323)	($ 2,137,803)	$ -	$ 23,305	$ 5,921,324	($ 35,977,498)	$ 19,076,803
47	1995	Contributions & Grants	$ 90,632,289	$ -	$ 30,491	$ 90,662,780	$ 10,852,528	$ -	($ 17,051)	$ -	$ 101,498,257	($ 270,966,959)
N/A	1609	Capital Contributions Paid	($ 4,068,286)	$ -	$ 36,296	($ 4,031,989)	($ 1,150,182)	$ -	$ -	$ -	($ 5,182,171)	$ 69,322,833
N/A	2005	Property Under Capital Leases	($ 8,579,706)	$ -	$ -	($ 8,579,706)	$ -	$ -	($ 2,222,154)	$ -	($ 10,801,861)	$ 5,013,560
		Sub-Total	**($ 2,713,928,550)**	**($ 4,811,651)**	**($ 9,822,504)**	**($ 2,728,562,705)**	**($ 174,185,452)**	**$ 19,120,897**	**$ 51,457**	**$ 68,001,341**	**($ 2,815,574,461)**	**$ 3,160,962,327**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -								$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -								$ -	$ -
		Total PP&E	**($ 2,713,928,550)**	**($ 4,811,651)**	**($ 9,822,504)**	**($ 2,728,562,705)**	**($ 174,185,452)**	**$ 19,120,897**	**$ 51,457**	**$ 68,001,341**	**($ 2,815,574,461)**	**$ 3,160,962,327**
		Depreciation Expense adj. from gain or los					$ -				$ -	
		Total					**($ 174,185,452)**					

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	($ 1,671,045)
Stores Equipment	
Net Depreciation	($ 172,514,406)

Notes:

1 The below CCA classes has been updated or added for these

CCA Class	OEB	Description	
N/A	1612	Land Rights	
1	1808	Buildings	
1	1908	Buildings & Fixtures	
50	1920	Computer Equipment - Hardware	n Class 52.
N/A	1609	Capital Contributions Paid	
N/A	2005	Property Under Capital Leases	

GROSS ASSETS

1. BREAKDOWN BY FUNCTION

In accordance with section 2.5.1.2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements"), Table 1 below provides a breakdown of gross assets by function from 2011 historical actuals through to 2015 test year forecast. The amount for construction work-in-progress ("CWIP") has also been provided. The amounts for CWIP have not been included in gross assets for rate base.

In accordance with the Uniform System of Accounts ("USoA"), Toronto Hydro has included asset accounts 1805 to 1860 in the category of distribution plant, accounts 1905 to 1980, accounts 1609 to 1612 and account 2005 in the category of general plant, and account 1995 in the category of capital contributions.

Table 1: Breakdown of Gross Assets by Function

Gross Assets	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Distribution Plant	4,214.3	4,404.1	4,547.4	4,726.0	4,646.6	5,413.8
General Plant	687.9	721.5	769.2	855.8	858.2	935.2
Capital Contributions	(294.5)	(316.6)	(338.9)	(354.3)	(354.3)	(372.5)
Total Before CWIP	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**
CWIP	257.8	336.9	401.3	515.5	516.1	507.4
Total Including CWIP	**4,865.6**	**5,145.9**	**5,379.0**	**5,743.1**	**5,666.6**	**6,483.9**

Note: Variances due to rounding may exist

/C

2. BREAKDOWN BY MAJOR PLANT ACCOUNT

In accordance with section 2.5.1.2 of the OEB's Filing Requirements (July 17, 2013), Table 2 below provides a breakdown of gross assets by major plant account from 2011 to 2015.

Table 2: Gross Assets Breakdown by Major Plant Account Summary

	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
General Plant	130.1	134.4	141.6	167.2	167.1	153.3
Equipment	180.1	178.5	181.8	189.7	189.7	197.1
IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
Gross Assets	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**

/C

Note: Variances due to rounding may exist

In accordance with the Uniform System of Accounts ("USoA"), Toronto Hydro's major plant categories are comprised of the following USoA accounts:

- **Land and Building**: 1805 Land; 1808 Buildings and Fixtures; 1810 Leasehold Improvements; 1905 Land
- **TS Primary Above 50**: 1815 Transformer Station Equipment
- **Distribution System**: 1820 Distribution Station Equipment
- **Poles and Wires**: 1830 Poles, Towers and Fixtures; 1835 O/H Conductors and Devices; 1840 U/G Conduit; 1845 U/G Conductors and Devices
- **Line Transformers**: 1850 Line Transformers
- **Services and Meters**: 1855 Services; 1860 Meters (including Smart Meters)
- **General Plant**: 1908 Buildings and Fixtures; 1910 Leasehold Improvements
- **Equipment**: 1915 Office Furniture and Equipment; 1930 Transportation Equipment; 1935 Stores Equipment; 1940 Tools, Shop and Garage Equipment; 1945 Measures & Test Equipment; 1955 Communication Equipment; 1960 Miscellaneous Equipment
- **IT Assets**: 1610 Miscellaneous Intangible Plant; 1920 Computer Equipment

- **Other Distribution Assets**: 1609 Capital Contributions Paid; 1611 Computer Software; 1612 Land Rights; 1970 Load Management-Customer; 1975 Load Management-Utility; 1980 System Supervisory Equipment; 2005 Property Under Capital Leases
- **Contributions and Grants**: 1995 Contributed Capital

Appendix A to this schedule provides a breakdown of gross assets by major plant account and USofA Account from 2011 to 2015.

Appendix A. Table 2 - Gross Assets Breakdown by Major Plant Account - Detailed by Uniform System of Account

	Description	2011 Historical CGAAP	2012 Historical UGAAP	2013 Historical UGAAP	2014 Bridge UGAAP	2014 Bridge MIFRS	2015 Test MIFRS
1905	Land	9.2	9.2	9.2	9.2	9.2	8.7
1805	Land	7.6	7.6	7.6	7.6	7.6	7.6
1808	Buildings and Fixtures	44.6	46.4	50.5	52.4	51.9	93.8
1810	Leasehold Improvements	-	-	-	-	-	-
	Subtotal Land and Buildings	61.3	63.1	67.3	69.1	68.7	110.0
1815	Transformer Station Equipment	10.5	11.0	11.0	11.1	11.1	12.3
	Subtotal TS Primary Above 50	10.5	11.0	11.0	11.1	11.1	12.3
1820	Distribution Station Equipment	222.6	226.5	229.3	245.5	244.2	291.4
	Subtotal Distribution System	222.6	226.5	229.3	245.5	244.2	291.4
1830	Poles, Towers and Fixtures	379.1	392.6	406.8	414.4	394.7	489.2
1835	O/H Conductors and Devices	413.0	433.1	462.6	486.9	481.2	557.3
1840	U/G Conduit	1,312.9	1,377.7	1,420.9	1,479.9	1,479.0	1,749.2
1845	U/G Conductors and Devices	788.6	834.6	888.7	919.3	898.6	1,028.6
	Subtotal Poles and Wires	2,893.6	3,037.9	3,179.0	3,300.4	3,253.5	3,824.2
1850	Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
	Subtotal Line Transformers	731.7	757.4	791.9	810.3	779.6	835.5
1855	Services	75.5	80.5	84.1	92.1	92.1	120.0
1860	Meters (includes Smart Meters)	228.2	236.7	194.0	206.7	206.7	229.0
	Subtotal Services and Meters	303.7	317.2	278.1	298.7	298.7	349.0
1908	Buildings and Fixtures	110.3	114.0	121.2	146.5	146.3	132.5
1910	Leasehold Improvements	19.8	20.4	20.4	20.7	20.7	20.8
	Subtotal General Plant	130.1	134.4	141.6	167.2	167.1	153.3
1915	Office Furniture and Equipment	20.5	21.7	22.3	24.6	24.6	24.8
1930	Transportation Equipment	78.0	73.2	72.9	77.1	77.1	81.0
1935	Stores Equipment	5.5	5.5	5.5	5.5	5.5	5.5
1940	Tools, Shop and Garage Equipment	39.2	40.3	42.6	43.1	43.1	44.9
1945	Measurement & Test Equipment	5.0	5.3	5.1	5.1	5.1	5.1
1955	Communication Equipment	31.5	32.1	33.1	33.9	33.9	35.4
1960	Miscellaneous Equipment	0.4	0.4	0.4	0.4	0.4	0.4
	Subtotal Equipment	180.1	178.5	181.8	189.7	189.7	197.1
1610	Miscellaneous Intangible Plant	-	-	-	-	-	-
1920	Computer Equipment	44.6	50.5	56.3	87.4	87.4	98.9
	Subtotal IT Assets	44.6	50.5	56.3	87.4	87.4	98.9
1609	Capital Contributions Paid	14.1	19.6	22.2	25.7	25.7	74.5
1611	Computer Software	222.6	242.3	268.4	283.2	283.2	309.3
1612	Land Rights	-	-	-	-	7.2	7.2
1970	Load Management-Customer	14.8	14.8	14.8	14.8	14.8	14.9
1975	Load Management-Utility	0.6	0.6	0.6	0.6	0.6	0.6
1980	System Supervisory Equipment	57.6	58.1	60.5	62.2	57.5	55.1
2005	Property Under Capital Leases	14.3	13.5	13.7	15.8	15.8	15.8
	Subtotal Other Distribution Assets	323.9	348.9	380.2	402.4	404.9	477.3
1995	Contributed Capital	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
	Subtotal Contributions and Grants	(294.5)	(316.6)	(338.8)	(354.3)	(354.3)	(372.5)
	GROSS FIXED ASSETS	**4,607.8**	**4,809.0**	**4,977.7**	**5,227.6**	**5,150.5**	**5,976.5**
2055	Construction Work in Process	257.8	336.9	401.3	515.5	516.1	507.4
	GROSS INCLUDING CWIP	**4,865.6**	**5,145.9**	**5,379.0**	**5,743.1**	**5,666.6**	**6,483.9**

WORKING CAPITAL ALLOWANCE (WCA)

Toronto Hydro determined the Working Capital Allowance ("WCA") included in its 2015 ratebase based on an updated Lead-Lag Study performed by Navigant Consulting Inc. ("Navigant"), which is filed as Exhibit 2A, Tab 3, Schedule 2. Navigant used Toronto Hydro's 2012 financial information to determine the revenue lead and expense lag for various detailed revenue and cost components. The methodology employed by Navigant in the current study is generally the same as that employed in the last Lead-Lag study which was filed in EB-2007-0680. Toronto Hydro confirms that for the purposes of the Lead-Lag Study, leads and lags were measured in days, and were dollar weighted.

The result of the Lead-Lag Study is a significant decrease in the WCA rate approved in the utility's last rebasing application (EB-2010-0142) from 12.88% of controllable expenses plus cost of power to 7.99% for the 2015 test year. The reduction was achieved **/C**
primarily as a result of two changes:

1) a significant decrease in the revenue lag due to improved billing and collection activities, and
2) a change in the weightings applied to revenue lag days from customers to class revenues.

Table 1 below presents a detailed calculation of the WCA for 2015. To calculate the WCA, the Cost of Power was determined by using: the split between RPP and non-RPP customers, 2015 forecast RPP, HOEP, and UTR.

Table 1: Working Capital Allowance Calculation

	2015 Expenses ($ millions)	**Working Capital Factor**		**Expenses * Working Capital Factor ($ millions)**	
Cost of Power	2,751.9	6.1%		167.0	
OM&A	269.5	5.8%		15.6	
Interest on Long Term Debt	82.0	2.4%		2.0	
Income and Capital Taxes	24.0	28.4%		6.8	/C
DRC	171.2	5.9%		10.2	
Sub-Total Working Capital Requirement				**201.7**	/C
HST at 13%		**Net Lag Days**	**Expenses * Net Lag Days/365 * 13% HST**		
Revenue	3,403.1	-5.5	-6.6		
Cost of Power	2,751.9	45.9	45.0		
OM&A Expenses	103.2	41.5	1.5		
HST Working Capital Requirement				**39.9**	
Total Working Capital				**241.5**	/C
Working Capital as % of Cost of Power and Controllable Expenses				**7.99%**	

Table 2 below provides a comparison of the Working Capital Requirements for the 2015 test year which have been included in the utility's rate base calculations (Exhibit 2A, Tab 1, Schedule 1), and the last OEB-approved WCA in 2011. This table shows that since 2011, Toronto Hydro has achieved a reduction of just under $60M in its WCA.

Table 2: Working Capital Allowance ($millions)

	2011 OEB Approved	2015 Test Year	
Working Capital Allowance	296.7	241.5	/C

NAVIGANT

Working Capital Requirements of Toronto Hydro Electric System Limited's Distribution Business

Prepared for:

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Section I: Executive Summary

Summary

This report provides the results of the working capital requirements of THESL's distribution business.

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

Results from the lead-lag study using 2012 data identify the following working capital amount in Table 1, below.

Table 1: Summary of Working Capital Requirements

Year	2012
Percentage of OMA	7.91%
Working Capital Requirement	$218,720,393

The results of the study indicate a lower working capital requirement compared to THESL's EB-2007-0680 distribution lead-lag study. A considerable amount of time has lapsed between the two studies. The primary reason for the difference is the decrease in retail revenue lag days due to the upgrade of THESL's Customer Information System since the prior study. The retail revenue lag days have decreased by approximately 20 percent. Table 2, below summarizes the detailed working capital requirements for 2012 calculated in the study.

Table 2: THESL Distribution Working Capital Requirements (2012)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses	Working Capital Requirements
Cost of Power	55.04	32.84	22.20	6.07%	$ 2,450,597,565	$ 148,654,316
OM&A Expenses	55.04	33.86	21.19	5.79%	$ 312,961,220	$ 18,115,434
PILS	55.04	(48.95)	103.99	28.41%	$ 7,831,000	$ 2,225,034
Interest Expense	55.04	46.17	8.87	2.42%	$ 76,173,950	$ 1,845,550
DRC	55.04	33.31	21.74	5.94%	$ 162,416,324	$ 9,645,577
Total					**$ 3,009,980,059**	**$ 180,485,912**
HST						$ 38,234,481
Total - Including HST						**$ 218,720,393**
Working Capital as a Percent of OM&A incl. Cost of Power						**7.91%**

Organization of the Report

Section II of the report discusses the lag times associated with THESL's collections of revenues. The section includes a description of the sources revenues and how an overall revenue lag is derived.

Section III presents the lead times associated with THESL's expenses. The section includes a description of the types of expenses incurred by THESL's distribution operations and how expenses are treated for the purposes of deriving an overall prov expenses lead.

Section IV presents a summary of the results from the study.

Section II: Revenue Lags

A distribution utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by THESL until the date payments are received from customers and funds are available to THESL.

Interviews with THESL personnel indicate that its distribution business receives funds from the following funding streams:

1. Retail Customers;
2. Other Sources (revenues from electricity retailers and revenues for miscellaneous services such as jobbing and contracting work performed by THESL); and,
3. The Ontario Clean Energy Benefit (OCEB).

The lag times associated with the funding streams above were weighted and combined to calculate an overall revenue lag time as shown below. Detailed data tables are provided in Appendix B.

Table 3: Summary of Revenue Lag

Description	Lag Days	Revenues	Weighting	Weighted Lag
Retail Revenue	54.78	$ 3,265,502,197	94.18%	51.59
Other Revenue	33.93	$ 25,540,425	0.74%	0.25
Ontario Clean Energy Benefit	62.98	$ 176,156,432	5.08%	3.20
Total		**$ 3,467,199,054**	**100.00%**	**55.04**

Retail Revenue Lag

Retail Revenue lag consists of the following components:

1. Service Lag;
2. Billing Lag;
3. Collections Lag; and,
4. Payment Processing Lag.

The lag times for each of the above components, when added together, results in the Retail Revenue Lag for the purpose of calculating the working capital requirements for THESL's distribution business. The components are intended to represent a continuous process from the end date of the customer's previous billing cycle to the date in which the payment is available to THESL. Figure 1 illustrates the start and end point for each component of THESL's retail revenue lag.

Figure 1: Retail Revenue Lag

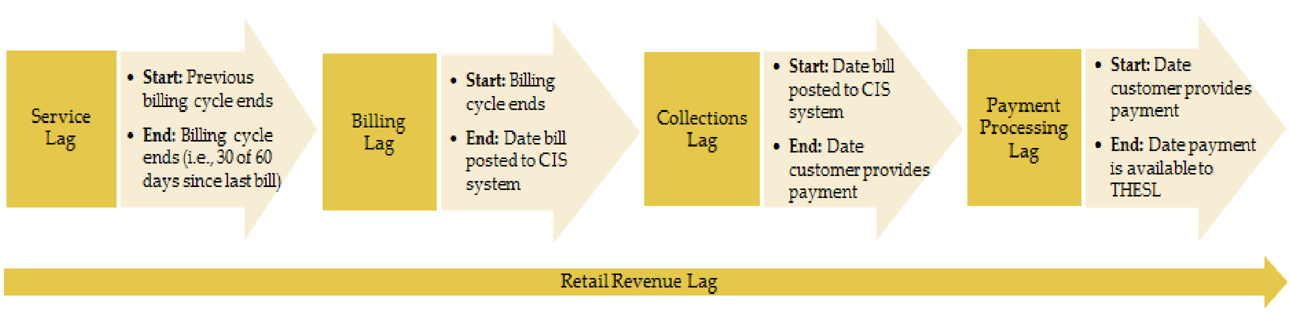

Table 3, below summarizes the total Retail Revenue Lag.

Table 4: Summary of Retail Revenue Lag

Description	Lag Days
Service Lag	18.72
Billing Lag	12.52
Collections Lag	22.21
Payment Processing Lag	1.32
Total	**54.78**

The estimation of each component of the Retail Revenue Lag is described below.

Service Lag

The Service Lag is the time from THESL's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Customer Service staff at THESL provided data which documented that approximately 78% of revenues are billed monthly and 22% of revenues are billed bi-monthly. Using the information provided, the Service Lag was estimated to be 18.72 days.

Billing Lag

The Billing Lag is the time period from when the customer's service period ends, which is typically defined as when the meter is read, and the time that the customer's bill is generated in the customer information system (CIS). Interviews with billing staff at THESL and analysis of meter billing data indicated that THESL customers have an average billing lag of 12.52 days, which is significantly shorter than billing lag in the prior study due to the implementation of a new CIS.

Collections Lag

The Collections Lag is the time period from when the bill is generated in the CIS, until the time when the customer provides a payment to THESL. The Collections Lag is measured by analyzing the receivables aging data provided by THESL. THESL's Collection lag was calculated to be 22.21 days was determined for THESL's distribution operations.

Payment Processing Lag

The Payment Processing lag is the time period from when the customer provides a payment to THESL until such time as the funds associated with that payment are available to the company. The Payment Processing Lag is measured by analyzing the payment methods used by THESL customers. Some examples of the payment methods used include credit card, pre-authorized payment and branch payment. THESL provided the processing time associated with each method of payment and the number of customers using each method of payment. Using such data provided by THESL for the calendar year 2012, a customer-weighted average payment processing lag of 1.32 days was determined for THESL's distribution operations.

Section III: Expense Leads

Expense Leads are defined as the time period between when a service is provided to THESL and when payment is required for that service. Typically services are provided in advance of payment which reduces the capital requirement of the company. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. Cost of Power;
2. OM&A Expenses;
3. Interest on Long Term Debt;
4. Payments in Lieu of Taxes; and,
5. Harmonized Sales Tax.

Cost of Power

For the purpose of the distribution lead-lag study, cost of power expenses were considered to consist of payments made by THESL to its vendors in the following categories:

1. Independent Electricity System Operator (IESO) Cost of Power Expenses;
2. Hydro One Low Voltage Charges;
3. Payments to Non-Utility Generators; and,
4. Payments to Renewable Energy Standard Offer Program (RESOP), Micro Feed-in Tariff (MFIT), and Feed-in Tariff (FIT) customers.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 32.84 days for cost of power expenses.

Table 5: Summary of Cost of Power Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
IESO Cost of Power	$ 2,442,084,555	99.65%	32.80	32.68
Hydro One Low Voltage Charges	$ 352,519	0.01%	32.22	0.00
Payments to Non-Utility Generators	$ 293,330	0.01%	32.26	0.00
Payments to RESOP, MFIT, and FIT customers	$ 7,867,160	0.32%	46.29	0.15
Total	**$ 2,450,597,565**	**100.00%**		**32.84**

IESO Cost of Power Expenses

THESL purchases its power supply requirements on a monthly basis from the IESO and pays for such supplies on a schedule defined by the IESO's billing and settlement procedures. Taking the information on actual payments made by THESL in 2012, a dollar-weighted Cost of Power expense lead time of 32.80 days was calculated. Table 6 below summarizes the components of the Cost of Power expense lead calculation.

Table 6: Summary of IESO Cost of Power Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 201,741,673	8.26%	2/21/2012	15.50	21.00	31.50	2.60
Feb 12	$ 189,300,906	7.75%	3/20/2012	14.50	20.00	30.50	2.36
Mar 12	$ 200,593,695	8.21%	4/23/2012	15.50	23.00	34.50	2.83
Apr 12	$ 182,265,321	7.46%	5/18/2012	15.00	18.00	31.00	2.31
May 12	$ 202,835,582	8.31%	6/20/2012	15.50	20.00	33.50	2.78
Jun 12	$ 217,612,164	8.91%	7/20/2012	15.00	20.00	33.00	2.94
Jul 12	$ 220,868,561	9.04%	8/21/2012	15.50	21.00	32.50	2.94
Aug 12	$ 231,368,962	9.47%	9/21/2012	15.50	21.00	34.50	3.27
Sep 12	$ 195,552,497	8.01%	10/19/2012	15.00	19.00	32.00	2.56
Oct 12	$ 198,526,123	8.13%	11/21/2012	15.50	21.00	34.50	2.80
Nov 12	$ 204,231,158	8.36%	12/20/2012	15.00	20.00	33.00	2.76
Dec 12	$ 197,187,913	8.07%	1/21/2013	15.50	21.00	32.50	2.62
Total	**$ 2,442,084,555**	**100.00%**					**32.80**

Hydro One Low Voltage Charges

THESL provides payment to Hydro One for low voltage charges on a monthly basis and pays for such charges on a monthly basis. Based upon information on payments made by THESL in 2012, a dollar-weighted Hydro One Low Voltage Charges Cost of Power expense lead time of 32.22 days was calculated. Table 7, below summarizes the components of the Hydro One Low Voltage Charges expense lead calculation.

Table 7: Summary of Hydro One Low Voltage Charges

Delivery Period		Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$	27,386	7.77%	2/16/2012	15.50	16.00	31.50	2.45
Feb 12	$	37,379	10.60%	3/16/2012	14.50	16.00	30.50	3.23
Mar 12	$	26,011	7.38%	4/19/2012	15.50	19.00	34.50	2.55
Apr 12	$	24,835	7.04%	5/16/2012	15.00	16.00	31.00	2.18
May 12	$	24,866	7.05%	6/16/2012	15.50	16.00	31.50	2.22
Jun 12	$	26,303	7.46%	7/18/2012	15.00	18.00	33.00	2.46
Jul 12	$	31,504	8.94%	8/17/2012	15.50	17.00	32.50	2.90
Aug 12	$	29,118	8.26%	9/19/2012	15.50	19.00	34.50	2.85
Sep 12	$	38,369	10.88%	10/17/2012	15.00	17.00	32.00	3.48
Oct 12	$	36,131	10.25%	11/17/2012	15.50	17.00	32.50	3.33
Nov 12	$	25,235	7.16%	12/16/2012	15.00	16.00	31.00	2.22
Dec 12	$	25,384	7.20%	1/17/2013	15.50	17.00	32.50	2.34
Total	**$**	**352,519**	**100.00%**					**32.22**

Payments to Non-Utility Generators

THESL purchases power supply from Non-Utility Generators on a monthly basis and pays for such supplies on a monthly basis. For the year 2012, a dollar-weighted expense lead time of 32.26 days was calculated. Table 8 below summarizes the components of the Non-Utility Generator payments expense lead calculation.

Table 8: Summary of Non-Utility Generator Payments

Delivery Period		Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$	34,011	11.59%	2/16/2012	15.50	16.00	31.50	3.65
Feb 12	$	18,356	6.26%	3/16/2012	14.50	16.00	30.50	1.91
Mar 12	$	13,579	4.63%	4/19/2012	15.50	19.00	34.50	1.60
Apr 12	$	13,586	4.63%	5/16/2012	15.00	16.00	31.00	1.44
May 12	$	14,235	4.85%	6/16/2012	15.50	16.00	31.50	1.53
Jun 12	$	13,825	4.71%	7/18/2012	15.00	18.00	33.00	1.56
Jul 12	$	31,504	10.74%	8/17/2012	15.50	17.00	32.50	3.49
Aug 12	$	29,118	9.93%	9/19/2012	15.50	19.00	34.50	3.42
Sep 12	$	38,369	13.08%	10/17/2012	15.00	17.00	32.00	4.19
Oct 12	$	36,131	12.32%	11/17/2012	15.50	17.00	32.50	4.00
Nov 12	$	25,235	8.60%	12/16/2012	15.00	16.00	31.00	2.67
Dec 12	$	25,384	8.65%	1/17/2013	15.50	17.00	32.50	2.81
Total	**$**	**293,330**	**100.00%**					**32.26**

Payments to RESOP, MFIT, and FIT Customers

THESL purchases power supply from RESOP, MFIT and FIT customers. Using payment information in 2012 and the service and billing lag values determined from the revenue analysis, a dollar-weighted expense lead time of 46.29 days was calculated. Table 9 below summarizes the components of the RESOP, MFIT, and FIT payments expense lead calculation. Additional detail can be found in Appendix B.

Table 9: RESOP, MFIT, and FIT Customer Payments

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
RESOP	$ 113,497	1.44%	38.41	0.55
MFIT	$ 1,843,520	23.43%	43.31	10.15
FIT	$ 5,910,143	75.12%	47.38	35.59
Total	**$ 7,867,160**	**100.00%**		**46.29**

OM&A Expenses

For the purpose of the distribution lead-lag study, OM&A expenses were considered to consist of payments made by THESL to its vendors in the following categories:

1. Payroll & Benefits;
2. Property Taxes;
3. Non-Resident Withholding Tax;
4. Corporate Procurement Card;
5. Lease Payments;
6. Outside Services; and,
7. Miscellaneous OM&A.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 33.86 days for OM&A expenses.

Table 10: Summary of OM&A Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
Payroll & Benefits	$ 207,829,884	66.41%	27.30	18.13
Property Taxes	$ 6,494,693	2.08%	(27.57)	(0.57)
Non-Resident Withholding Tax	$ 249,209	0.08%	29.44	0.02
Corporate Procurement Card	$ 187,473	0.06%	26.21	0.02
Lease Payments	$ 8,971,928	2.87%	12.85	0.37
Outside Services	$ 49,864,366	15.93%	53.51	8.53
Miscellaneous OM&A	$ 39,363,668	12.58%	58.56	7.37
Total	**$ 312,961,220**	**100.00%**		**33.86**

Payroll & Benefits

The following items were considered to be expenses related to the Payroll & Benefits of THESL:

1. Two types of payroll including basic and board of directors payroll;
2. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings;
3. Contributions made by THESL to the THESL Pension Plan;
4. Group Health, Dental, and Life Insurance related administrative fees and claims, long-term disability, accidental death and dismemberment, and employee assistance program;
5. Payments made by THESL on account of the Employer Health Tax (EHT); and,
6. Payments made by THESL to the Workplace Safety and Insurance Board (WSIB).

When all Payroll, Withholdings and Benefits were dollar-weighted using actual payment data, the weighted average expense lead time associated with Payroll & Benefits was determined to be 27.30 days as shown in Table 11, below. Additional detail can be found in Appendix B.

Table 11: Summary of Payroll & Benefits Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
Payroll	$ 102,963,943	19.68	49.54%	9.75
Withholdings	$ 52,044,775	33.58	25.04%	8.41
Pensions	$ 29,800,561	56.83	14.34%	8.15
Group Life Insurance	$ 2,760,011	(4.25)	1.33%	(0.06)
Group Medical & Dental Claims	$ 13,286,318	0.50	6.39%	0.03
Long-Term Disability	$ 2,160,971	(4.25)	1.04%	(0.04)
Accidental Death and Dismemberment	$ 28,747	(4.25)	0.01%	(0.00)
Employee Assistance Program	$ 118,870	(4.10)	0.06%	(0.00)
EHT	$ 3,167,626	42.39	1.52%	0.65
WSIB	$ 1,498,062	57.96	0.72%	0.42
Total	**$ 207,829,884**		**100.00%**	**27.30**

Property Taxes

THESL makes property tax payments to the City of Toronto and taxing authorities in the Province of Ontario. These payments are made in the current year for the current year and are typically made in installments. Using the payment dates and amounts associated with THESL's distribution business for calendar year 2012, a dollar-weighted expense lead (-lag) time of negative 27.57 days was determined. Table 12, below summarizes the components of the property tax expense lead calculation. Additional detail can be found in Appendix B.

Table 12: Summary of Property Tax Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
PIL Property Tax	$ 53,851	0.83%	(15.39)	(0.13)
Property Tax	$ 6,440,842	99.17%	(27.67)	(27.44)
Total	**$ 6,494,693**	**100.00%**		**(27.57)**

Non-Resident Withholding Tax

THESL makes non-resident withholding tax payments to the relevant taxing authority. These payments are made on a monthly basis. Using actual payment dates and amounts provided by THESL, a dollar-weighted expense lead time of 29.44 days was determined. Table 13, below summarizes the components of the non-resident withholding tax expense lead calculation.

Table 13: Summary of Non-Resident Withholding Tax Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 17,561	7.05%	1/13/2012	15.50	13.00	28.50	2.01
Feb 12	$ 32,228	12.93%	2/15/2012	15.50	15.00	30.50	3.94
Mar 12	$ 5,623	2.26%	3/15/2012	14.00	16.00	30.00	0.68
Apr 12	$ 56,377	22.62%	4/13/2012	15.50	13.00	28.50	6.45
May 12	$ 9,885	3.97%	5/15/2012	15.00	15.00	30.00	1.19
Jun 12	$ 12,593	5.05%	6/15/2012	15.50	15.00	30.50	1.54
Jul 12	$ 16,577	6.65%	7/13/2012	15.00	13.00	28.00	1.86
Aug 12	$ 4,793	1.92%	8/15/2012	15.50	15.00	30.50	0.59
Sep 12	$ 23,459	9.41%	9/14/2012	15.50	14.00	29.50	2.78
Oct 12	$ 37,550	15.07%	10/15/2012	15.00	15.00	30.00	4.52
Nov 12	$ 15,812	6.34%	11/15/2012	15.50	15.00	30.50	1.94
Dec 12	$ 16,751	6.72%	12/14/2012	15.00	14.00	29.00	1.95
Total	**$ 249,209**	**100.00%**					**29.44**

Corporate Procurement Card

Procurement (or charge) cards are used by the THESL's employees for a variety of company related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on invoice and payment information provided by THESL, a dollar-weighted expense lead time of 26.21 days was determined. Table 14 below summarizes the components of the corporate procurement card expense lead calculation.

Table 14: Summary of Corporate Procurement Card Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 15,927	8.50%	1/13/2012	15.50	11.00	26.50	2.25
Feb 12	$ 11,782	6.28%	2/15/2012	14.50	11.00	25.50	1.60
Mar 12	$ 4,624	2.47%	3/15/2012	15.50	11.00	26.50	0.65
Apr 12	$ 5,756	3.07%	4/13/2012	15.00	11.00	26.00	0.80
May 12	$ 12,882	6.87%	5/15/2012	15.50	11.00	26.50	1.82
Jun 12	$ 14,794	7.89%	6/15/2012	15.00	11.00	26.00	2.05
Jul 12	$ 4,246	2.27%	7/13/2012	15.50	11.00	26.50	0.60
Aug 12	$ 5,776	3.08%	8/15/2012	15.50	11.00	26.50	0.82
Sep 12	$ 6,420	3.42%	9/14/2012	15.00	11.00	26.00	0.89
Oct 12	$ 13,849	7.39%	10/15/2012	15.50	11.00	26.50	1.96
Nov 12	$ 59,012	31.48%	11/15/2012	15.00	11.00	26.00	8.18
Dec 12	$ 32,403	17.28%	12/14/2012	15.50	11.00	26.50	4.58
Total	**$ 187,473**	**100.00%**					**26.21**

Lease Payments

Using actual payment dates and amounts provided by THESL, a dollar-weighted lease expense lead time of 12.85 days was determined. Table 15, below summarizes the components of the lease expense lead calculation.

Table 15: Summary of Lease Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 844,861	9.42%	48.81	0.51	49.32	4.64
Feb 12	$ 740,722	8.26%	14.93	5.63	20.56	1.70
Mar 12	$ 740,722	8.26%	15.07	(7.91)	7.16	0.59
Apr 12	$ 740,722	8.26%	15.21	(7.35)	7.86	0.65
May 12	$ 740,722	8.26%	15.29	(9.35)	5.94	0.49
Jun 12	$ 740,722	8.26%	15.21	(2.36)	12.86	1.06
Jul 12	$ 719,847	8.02%	15.28	(3.25)	12.03	0.97
Aug 12	$ 740,722	8.26%	15.50	(6.91)	8.59	0.71
Sep 12	$ 740,722	8.26%	15.21	(10.48)	4.73	0.39
Oct 12	$ 740,722	8.26%	15.29	(4.20)	11.08	0.91
Nov 12	$ 740,722	8.26%	15.21	(10.76)	4.45	0.37
Dec 12	$ 740,722	8.26%	15.29	(10.77)	4.52	0.37
Total	**$ 8,971,928**	**100.00%**				**12.85**

Outside Services

THESL engages outside services to provide assistance in the areas of engineering, information technology, receivables management, accounting, and general consulting. Based on 2012 transactions in THESL's accounts payable system under the outside services category, a dollar-weighted expense lead time of 53.51 days was determined. Table 16, below summarizes the components of outside services expense lead calculation.

Table 16: Summary of Outside Services Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 4,612,817	9.25%	14.38	37.70	52.08	4.82
Feb-12	$ 2,781,515	5.58%	14.58	43.98	58.56	3.27
Mar-12	$ 3,033,721	6.08%	12.29	41.93	54.22	3.30
Apr-12	$ 2,865,796	5.75%	14.44	46.31	60.75	3.49
May-12	$ 6,084,596	12.20%	28.24	13.45	41.68	5.09
Jun-12	$ 5,110,106	10.25%	14.48	47.74	62.22	6.38
Jul-12	$ 3,904,682	7.83%	29.29	13.85	43.14	3.38
Aug-12	$ 3,800,454	7.62%	13.96	35.58	49.54	3.78
Sep-12	$ 4,129,948	8.28%	19.05	33.91	52.97	4.39
Oct-12	$ 5,325,608	10.68%	30.95	32.32	63.28	6.76
Nov-12	$ 4,810,172	9.65%	13.73	44.26	57.98	5.59
Dec-12	$ 3,404,952	6.83%	13.81	34.29	48.10	3.28
Total	**$ 49,864,366**	**100.00%**				**53.51**

Miscellaneous OM&A

The Miscellaneous OM&A category includes items such as product purchases, equipment rentals, and provision of general services to THESL. Based on 2012 transactions in THESL's accounts payable system under the Miscellaneous OM&A category, a dollar-weighted expense lead time of 58.56 days was derived. Table 17, below summarizes the components of miscellaneous OM&A expense lead calculation.

Table 17: Summary of Miscellaneous OM&A Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 5,024,613	12.76%	74.53	(17.64)	56.88	7.26
Feb-12	$ 3,197,116	8.12%	57.20	(49.67)	7.53	0.61
Mar-12	$ 3,513,623	8.93%	39.78	(0.92)	38.86	3.47
Apr-12	$ 4,245,067	10.78%	60.99	62.93	123.92	13.36
May-12	$ 3,438,457	8.74%	59.78	(30.27)	29.51	2.58
Jun-12	$ 2,285,298	5.81%	15.80	35.12	50.92	2.96
Jul-12	$ 3,326,833	8.45%	49.06	(0.03)	49.03	4.14
Aug-12	$ 3,235,973	8.22%	60.64	(6.81)	53.84	4.43
Sep-12	$ 2,390,997	6.07%	16.04	42.90	58.94	3.58
Oct-12	$ 2,283,193	5.80%	15.93	36.91	52.84	3.06
Nov-12	$ 3,132,224	7.96%	56.56	18.42	74.98	5.97
Dec-12	$ 3,290,273	8.36%	66.50	18.88	85.38	7.14
Total	**$ 39,363,668**	**100.00%**				**58.56**

Interest on Short-Term and Long-Term Debt

THESL makes interest payments on long-term and short-term intercompany promissory notes out of current year revenues. Payments on long-term debt are generally made twice a year. Though short-term debt was not part of THESL's financing in the base year of the analysis (2012), discussions with THESL staff indicate that short-term debt is expected to be a part of THESL's financing in the 2015-2019 period. Payments for short-term intercompany promissory notes in 2013 were included to reflect a known and measurable change from the base year of the analysis. Table 18, below summarizes the components of the interest expense lead calculation. Taking into account the various long term and short term debt instruments, a dollar-weighted expense lead time of 46.17 days was determined for the 2012 calendar year.

Table 18: Summary of Interest Expenses

Description	Amounts	Weighting	Expense Lead Time	Weighted Lead Time
2012 Long-term debt	$ 75,272,180	98.82%	46.38	45.83
2013 Short-term debt	$ 901,769	1.18%	28.84	0.34
Total	**$ 76,173,950**	**100.00%**		**46.17**

Debt Retirement Charge (DRC)

THESL makes payments for the debt retirement charge on a monthly basis to the Ontario Electricity Financial Corporation. Using payment amounts that were made in calendar year 2012, a dollar-weighted expense lead time of 33.31 days was determined for DRC. Table 19, below summarizes the components of the DRC expense lead calculation.

Table 19: Summary of DRC Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 12,414,868	7.64%	1/18/2012	15.50	18.00	33.50	2.56
Feb 12	$ 13,362,129	8.23%	2/17/2012	15.50	17.00	32.50	2.67
Mar 12	$ 13,574,039	8.36%	3/16/2012	14.00	17.00	31.00	2.59
Apr 12	$ 14,210,958	8.75%	4/18/2012	15.50	18.00	33.50	2.93
May 12	$ 12,537,844	7.72%	5/18/2012	15.00	18.00	33.00	2.55
Jun 12	$ 12,721,780	7.83%	6/18/2012	15.50	18.00	33.50	2.62
Jul 12	$ 12,952,542	7.97%	7/18/2012	15.00	18.00	33.00	2.63
Aug 12	$ 14,352,950	8.84%	8/20/2012	15.50	20.00	35.50	3.14
Sep 12	$ 15,787,738	9.72%	9/18/2012	15.50	18.00	33.50	3.26
Oct 12	$ 14,192,275	8.74%	10/18/2012	15.00	18.00	33.00	2.88
Nov 12	$ 13,282,921	8.18%	11/19/2012	15.50	19.00	34.50	2.82
Dec 12	$ 13,026,281	8.02%	12/18/2012	15.00	18.00	33.00	2.65
Total	**$ 162,416,324**	**100.00%**					**33.31**

Payment in Lieu of Taxes (PILs)

THESL makes payments in lieu of taxes in installments to the relevant taxing authorities. Using payment amounts that were made in calendar year 2012, a dollar-weighted expense lead time of negative 48.95 days was determined for PILs. Table 20, below summarizes the components of the PILS expense lead calculation.

Table 20: Summary of PILs Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
2012	$ 1,665,000	21.26%	1/31/2012	183.00	(335.00)	(152.00)	(32.32)
2012	$ 1,665,000	21.26%	2/29/2012	183.00	(306.00)	(123.00)	(26.15)
2012	$ 1,822,000	23.27%	4/30/2012	183.00	(245.00)	(62.00)	(14.43)
2012	$ 914,000	11.67%	5/31/2012	183.00	(214.00)	(31.00)	(3.62)
2012	$ 541,000	6.91%	9/28/2012	183.00	(94.00)	89.00	6.15
2012	$ 612,000	7.82%	10/31/2012	183.00	(61.00)	122.00	9.53
2012	$ 612,000	7.82%	11/30/2012	183.00	(31.00)	152.00	11.88
Total	**$ 7,831,000**	**100.00%**					**(48.95)**

Harmonized Sales Tax (HST)

The expense lead times associated with the following items that attract HST were considered in THESL's distribution lead-lag study.

1. Revenues;
2. Cost of Power; and,
3. OM&A[1].

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in Table 21. Note that the statutory approach described at the outset was used to determine the expense lead times associated with THESL's remittances and disbursements of HST (i.e., remittances are generally on the last day of the month following the date of the applicable return).

Table 21: Summary of HST Working Capital Amounts

Description	HST Lead Time	Working Capital Factor	2012
Revenues	(5.47)	-1.50%	$ (6,347,016)
Cost of Power	45.92	12.55%	$ 39,967,966
OM&A Expenses	41.50	11.34%	$ 4,613,531
Total			**$ 38,234,481**

[1] Costs within OM&A that attract HST include Corporate Procurement Card, Outside Services, and Miscellaneous OM&A.

Section IV: Conclusions

Using the results described under the discussion of revenue lags and expense leads, and applying them to THESL's distribution expenses for 2012, THESL's working capital requirements were determined. Table 22, below summarizes the working capital requirements for 2012 calculated in the study.

Table 22: THESL Distribution Working Capital Requirements (2012)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses	Working Capital Requirements
Cost of Power	55.04	32.84	22.20	6.07%	$ 2,450,597,565	$ 148,654,316
OM&A Expenses	55.04	33.86	21.19	5.79%	$ 312,961,220	$ 18,115,434
PILS	55.04	(48.95)	103.99	28.41%	$ 7,831,000	$ 2,225,034
Interest Expense	55.04	46.17	8.87	2.42%	$ 76,173,950	$ 1,845,550
DRC	55.04	33.31	21.74	5.94%	$ 162,416,324	$ 9,645,577
Total					**$ 3,009,980,059**	**$ 180,485,912**
HST						$ 38,234,481
Total - Including HST						**$ 218,720,393**
Working Capital as a Percent of OM&A incl. Cost of Power						**7.91%**

The results of the study indicate a lower working capital requirement compared to THESL's EB-2007-0680 distribution lead-lag study. A considerable amount of time has lapsed between the two studies. The primary reason for the difference is the decrease in retail revenue lag days, due to the upgrade of THESL's Customer Information System since the prior study. The retail revenue lag days have decreased by approximately 20 percent.

Appendix A: Working Capital Methodology

Working capital is the amount of funds that are required to finance the day-to-day operations of a regulated utility and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for determination of working capital and was used by Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to THESL (or "lag") together with the time between which THESL receives goods and services from its vendors and pays for them at a later date (or "lead")[2]. "Leads" and "Lags" are both measured in days and are dollar-weighted where appropriate.[3] The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in THESL's rate base for the purpose of deriving revenue requirements.

Key Concepts

Two key concepts need to be defined as they appear throughout the report:

Mid-Point Method

When a service is provided to (or by) THESL over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([Y-X]+1)}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. The formula uses the number of days in a year (A) and the number of periods in a year (B):

$$\text{Mid-Point} = \frac{A/B}{2}$$

Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of the study may utilize dates on which actual payments were made to (or by) THESL. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation with significant penalties for late payments. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

Expense Lead Components

As used in the study, Expense Leads are defined to consist of two components:

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[2] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

[3] The notion of dollar-weighting is pursued further in the sub-section titled "Key Concepts".

1. Service Lead component (services are assumed to be provided to THESL evenly around the mid-point of the service period), and
2. Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left THESL's possession).

Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 Million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars actually flow.

Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions; and,
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of THESL's operations, interviews with personnel within THESL's Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) THESL, over what time period was this service provided;
2. Who are the buyers (or sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes;
5. Are there any new rules or regulations governing transactions relating to distribution operations that are expected to materialize over the time frame considered in this report; and,
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times)

Appendix B: Detailed Data Tables

Other Revenues

Table 23: Summary of Other Revenues

Description	Amounts	Weighting	Revenue Lag Time	Weighted Lag Time
Hydro One Sub-Station	$ 431,151	1.69%	273.00	4.61
Demand Billable	$ 25,109,273	98.31%	29.83	29.32
Total	**$ 25,540,425**	**100.00%**		**33.93**

OCEB

Table 24: Summary of OCEB

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 14,777,518	8.39%	3/16/2012	15.50	45.00	60.50	5.08
Feb 12	$ 16,082,331	9.13%	4/18/2012	14.50	49.00	63.50	5.80
Mar 12	$ 15,985,774	9.07%	5/16/2012	15.50	46.00	61.50	5.58
Apr 12	$ 14,762,648	8.38%	6/18/2012	15.00	49.00	64.00	5.36
May 12	$ 14,085,387	8.00%	7/18/2012	15.50	48.00	63.50	5.08
Jun 12	$ 13,976,849	7.93%	8/17/2012	15.00	48.00	63.00	5.00
Jul 12	$ 16,150,445	9.17%	9/19/2012	15.50	50.00	65.50	6.01
Aug 12	$ 18,228,456	10.35%	10/17/2012	15.50	47.00	62.50	6.47
Sep 12	$ 14,618,252	8.30%	11/16/2012	15.00	47.00	62.00	5.15
Oct 12	$ 12,904,170	7.33%	12/18/2012	15.50	48.00	63.50	4.65
Nov 12	$ 12,919,262	7.33%	1/16/2013	15.00	47.00	62.00	4.55
Dec 12	$ 11,665,341	6.62%	2/18/2013	15.50	49.00	64.50	4.27
Total	**$ 176,156,432**	**100.00%**					**62.98**

RESOP

Table 25: Summary of Payments to RESOP Customers

Payment Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 2,254	1.99%	15.79	22.43	38.21	0.76
Feb 12	$ 4,998	4.40%	16.29	22.43	38.71	1.70
Mar 12	$ 6,013	5.30%	16.29	22.43	38.71	2.05
Apr 12	$ 11,184	9.85%	15.29	22.43	37.71	3.72
May 12	$ 13,375	11.78%	16.11	22.43	38.54	4.54
Jun 12	$ 12,914	11.38%	15.90	22.43	38.33	4.36
Jul 12	$ 9,305	8.20%	16.29	22.43	38.71	3.17
Aug 12	$ 19,542	17.22%	15.79	22.43	38.21	6.58
Sep 12	$ 8,905	7.85%	16.29	22.43	38.71	3.04
Oct 12	$ 12,650	11.15%	16.28	22.43	38.71	4.31
Nov 12	$ 8,856	7.80%	15.79	22.43	38.21	2.98
Dec 12	$ 3,500	3.08%	16.29	22.43	38.71	1.19
Total	**$ 113,497**	**100.00%**				**38.41**

MFIT

Table 26: Summary of Payments to MFIT Customers

Payment Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 34,830	1.89%	15.98	27.09	43.07	0.81
Feb 12	$ 45,649	2.48%	16.46	27.09	43.54	1.08
Mar 12	$ 73,170	3.97%	16.43	27.09	43.52	1.73
Apr 12	$ 125,758	6.82%	15.46	27.09	42.54	2.90
May 12	$ 145,497	7.89%	16.44	27.09	43.53	3.44
Jun 12	$ 149,706	8.12%	15.96	27.09	43.05	3.50
Jul 12	$ 261,612	14.19%	16.44	27.09	43.53	6.18
Aug 12	$ 308,020	16.71%	15.96	27.09	43.05	7.19
Sep 12	$ 247,772	13.44%	16.46	27.09	43.54	5.85
Oct 12	$ 218,745	11.87%	16.45	27.09	43.54	5.17
Nov 12	$ 121,296	6.58%	15.96	27.09	43.04	2.83
Dec 12	$ 111,465	6.05%	16.46	27.09	43.54	2.63
Total	**$ 1,843,520**	**100.00%**				**43.31**

FIT

Table 27: Summary of Payments to FIT Customers

Payment Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$ 51,547	0.87%	15.88	31.24	47.12	0.41
Feb 12	$ 106,029	1.79%	16.38	31.24	47.62	0.85
Mar 12	$ 154,218	2.61%	16.38	31.24	47.62	1.24
Apr 12	$ 339,753	5.75%	15.38	31.24	46.62	2.68
May 12	$ 411,174	6.96%	15.65	31.24	46.89	3.26
Jun 12	$ 680,917	11.52%	16.09	31.24	47.34	5.45
Jul 12	$ 607,174	10.27%	16.38	31.24	47.62	4.89
Aug 12	$ 785,193	13.29%	16.03	31.24	47.28	6.28
Sep 12	$ 885,352	14.98%	16.38	31.24	47.62	7.13
Oct 12	$ 757,723	12.82%	16.38	31.24	47.62	6.11
Nov 12	$ 635,045	10.74%	15.88	31.24	47.12	5.06
Dec 12	$ 496,019	8.39%	16.38	31.24	47.62	4.00
Total	**$ 5,910,143**	**100.00%**				**47.38**

Payroll

Table 28: Summary of Payroll Expenses

Delivery Period (Pay Period)	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
12/18/2011 to 12/31/2011	$ 3,743,615	3.64%	1/4/2012	7.00	4.00	11.00	0.40
01/01/2012 to 01/14/2012	$ 3,685,570	3.58%	1/18/2012	7.00	4.00	11.00	0.39
01/15/2012 to 01/28/2012	$ 3,637,840	3.53%	2/1/2012	7.00	4.00	11.00	0.39
01/29/2012 to 02/11/2012	$ 3,951,309	3.84%	2/15/2012	7.00	4.00	11.00	0.42
02/12/2012 to 02/25/2012	$ 3,939,521	3.83%	2/29/2012	7.00	4.00	11.00	0.42
02/26/2012 to 03/10/2012	$ 3,593,195	3.49%	3/14/2012	7.00	4.00	11.00	0.38
03/11/2012 to 03/24/2012	$ 3,448,774	3.35%	3/28/2012	7.00	4.00	11.00	0.37
03/25/2012 to 04/07/2012	$ 3,323,462	3.23%	4/11/2012	7.00	4.00	11.00	0.36
04/08/2012 to 04/21/2012	$ 3,638,829	3.53%	4/25/2012	7.00	4.00	11.00	0.39
04/22/2012 to 05/05/2012	$ 3,722,814	3.62%	5/9/2012	7.00	4.00	11.00	0.40
05/06/2012 to 05/19/2012	$ 3,674,061	3.57%	5/23/2012	7.00	4.00	11.00	0.39
05/20/2012 to 06/02/2012	$ 3,737,336	3.63%	6/6/2012	7.00	4.00	11.00	0.40
06/03/2012 to 06/16/2012	$ 3,721,799	3.61%	6/20/2012	7.00	4.00	11.00	0.40
06/17/2012 to 06/30/2012	$ 3,750,644	3.64%	7/4/2012	7.00	4.00	11.00	0.40
07/01/2012 to 07/14/2012	$ 3,863,603	3.75%	7/18/2012	7.00	4.00	11.00	0.41
07/15/2012 to 07/28/2012	$ 3,823,881	3.71%	8/1/2012	7.00	4.00	11.00	0.41
07/29/2012 to 08/11/2012	$ 3,908,038	3.80%	8/15/2012	7.00	4.00	11.00	0.42
08/12/2012 to 08/25/2012	$ 3,880,714	3.77%	8/29/2012	7.00	4.00	11.00	0.41
08/26/2012 to 09/08/2012	$ 3,841,950	3.73%	9/12/2012	7.00	4.00	11.00	0.41
09/09/2012 to 09/22/2012	$ 3,811,314	3.70%	9/26/2012	7.00	4.00	11.00	0.41
09/23/2012 to 10/06/2012	$ 3,802,499	3.69%	10/10/2012	7.00	4.00	11.00	0.41
10/07/2012 to 10/20/2012	$ 3,934,557	3.82%	10/24/2012	7.00	4.00	11.00	0.42
10/21/2012 to 11/03/2012	$ 4,193,257	4.07%	11/7/2012	7.00	4.00	11.00	0.45
11/04/2012 to 11/17/2012	$ 4,329,636	4.21%	11/21/2012	7.00	4.00	11.00	0.46
11/18/2012 to 12/01/2012	$ 4,121,857	4.00%	12/5/2012	7.00	4.00	11.00	0.44
12/02/2012 to 12/15/2012	$ 4,157,888	4.04%	12/19/2012	7.00	4.00	11.00	0.44
01/01/2011 to 12/31/2011	$ 3,416,730	3.32%	3/28/2012	182.50	88.00	270.50	8.98
01/01/2012 to 03/31/2012	$ 92,750	0.09%	3/15/2012	45.50	(16.00)	29.50	0.03
04/01/2012 to 06/30/2012	$ 87,750	0.09%	7/5/2012	45.50	5.00	50.50	0.04
07/01/2012 to 09/30/2012	$ 65,875	0.06%	9/13/2012	46.00	(17.00)	29.00	0.02
10/01/2012 to 12/31/2012	$ 62,875	0.06%	12/6/2012	46.00	(25.00)	21.00	0.01
Total	**$ 102,963,943**	**100.00%**					**19.68**

Withholdings

Table 29: Summary of Withholdings Expenses

Delivery Period (Pay Period)	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
12/18/2011 to 12/31/2011	$ 2,371,119	4.48%	1/4/2012	7.00	11.00	18.00	0.82
01/01/2012 to 01/14/2012	$ 2,314,472	4.37%	1/18/2012	7.00	11.00	18.00	0.80
01/15/2012 to 01/28/2012	$ 2,291,856	4.33%	2/1/2012	7.00	13.00	20.00	0.88
01/29/2012 to 02/11/2012	$ 2,472,835	4.67%	2/15/2012	7.00	13.00	20.00	0.95
02/12/2012 to 02/25/2012	$ 2,397,009	4.53%	2/29/2012	7.00	16.00	23.00	1.06
02/26/2012 to 03/10/2012	$ 2,173,168	4.99%	3/14/2012	7.00	16.00	23.00	0.96
03/11/2012 to 03/24/2012	$ 2,827,668	10.63%	3/28/2012	7.00	11.00	18.00	0.98
03/25/2012 to 04/07/2012	$ 1,922,646	4.45%	4/11/2012	7.00	11.00	18.00	0.66
04/08/2012 to 04/21/2012	$ 2,153,758	4.07%	4/25/2012	7.00	12.00	19.00	0.79
04/22/2012 to 05/05/2012	$ 2,102,868	3.97%	5/9/2012	7.00	12.00	19.00	0.77
05/06/2012 to 05/19/2012	$ 1,942,826	3.67%	5/23/2012	7.00	17.00	24.00	0.90
05/20/2012 to 06/02/2012	$ 1,981,111	3.74%	6/6/2012	7.00	10.00	17.00	0.65
06/03/2012 to 06/16/2012	$ 1,863,961	3.52%	6/20/2012	7.00	10.00	17.00	0.61
06/17/2012 to 06/30/2012	$ 1,734,066	3.28%	7/4/2012	7.00	11.00	18.00	0.60
07/01/2012 to 07/14/2012	$ 1,710,896	3.23%	7/18/2012	7.00	11.00	18.00	0.59
07/15/2012 to 07/28/2012	$ 1,560,219	2.95%	8/1/2012	7.00	13.00	20.00	0.60
07/29/2012 to 08/11/2012	$ 1,564,785	2.96%	8/15/2012	7.00	13.00	20.00	0.60
08/12/2012 to 08/25/2012	$ 1,476,121	2.79%	8/29/2012	7.00	12.00	19.00	0.54
08/26/2012 to 09/08/2012	$ 1,432,966	2.71%	9/12/2012	7.00	11.00	18.00	0.50
09/09/2012 to 09/22/2012	$ 1,404,023	2.65%	9/26/2012	7.00	11.00	18.00	0.49
09/23/2012 to 10/06/2012	$ 1,383,932	2.61%	10/10/2012	7.00	11.00	18.00	0.48
10/07/2012 to 10/20/2012	$ 1,480,490	2.80%	10/24/2012	7.00	16.00	23.00	0.65
10/21/2012 to 11/03/2012	$ 1,661,792	3.14%	11/7/2012	7.00	16.00	23.00	0.73
11/04/2012 to 11/17/2012	$ 1,788,194	3.38%	11/21/2012	7.00	18.00	25.00	0.86
11/18/2012 to 12/01/2012	$ 1,604,248	3.03%	12/5/2012	7.00	11.00	18.00	0.55
12/02/2012 to 12/15/2012	$ 1,626,355	3.07%	12/19/2012	7.00	13.00	20.00	0.62
Total	**$ 52,044,775**	**100.00%**					**33.58**

Pensions

Table 30: Summary of Pension Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Feb 12	$ 2,207,160	7.41%	2/28/2012	7.00	51.49	58.49	4.33
Mar 12	$ 2,379,281	7.98%	3/31/2012	7.00	55.99	62.99	5.03
Apr 12	$ 5,293,218	17.76%	4/30/2012	7.00	46.61	53.61	9.52
May 12	$ 2,398,137	8.05%	5/31/2012	7.00	47.01	54.01	4.35
Jun 12	$ 2,397,522	8.05%	6/30/2012	7.00	49.02	56.02	4.51
Jul 12	$ 2,372,761	7.96%	7/31/2012	7.00	51.94	58.94	4.69
Aug 12	$ 2,346,717	7.87%	8/31/2012	7.00	55.02	62.02	4.88
Sep 12	$ 3,505,145	11.76%	9/30/2012	7.00	50.00	57.00	6.70
Oct 12	$ 2,310,456	7.75%	10/31/2012	7.00	46.04	53.04	4.11
Nov 12	$ 2,301,748	7.72%	11/30/2012	7.00	48.01	55.01	4.25
Dec 12	$ 2,288,416	7.68%	12/31/2012	7.00	51.00	58.00	4.45
Total	**$ 29,800,561**	**100.00%**					**56.83**

Group Life Insurance

Table 31: Summary of Group Life Insurance Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 225,021	8.15%	1/11/2012	15.50	(20.00)	(4.50)	(0.37)
Feb-12	$ 225,814	8.18%	2/11/2012	14.50	(18.00)	(3.50)	(0.29)
Mar-12	$ 228,422	8.28%	3/11/2012	15.50	(20.00)	(4.50)	(0.37)
Apr-12	$ 243,951	8.84%	4/11/2012	15.00	(19.00)	(4.00)	(0.35)
May-12	$ 246,579	8.93%	5/11/2012	15.50	(20.00)	(4.50)	(0.40)
Jun-12	$ 226,522	8.21%	6/11/2012	15.00	(19.00)	(4.00)	(0.33)
Jul-12	$ 225,714	8.18%	7/11/2012	15.50	(20.00)	(4.50)	(0.37)
Aug-12	$ 226,913	8.22%	8/11/2012	15.50	(20.00)	(4.50)	(0.37)
Sep-12	$ 226,673	8.21%	9/11/2012	15.00	(19.00)	(4.00)	(0.33)
Oct-12	$ 229,313	8.31%	10/11/2012	15.50	(20.00)	(4.50)	(0.37)
Nov-12	$ 228,291	8.27%	11/11/2012	15.00	(19.00)	(4.00)	(0.33)
Dec-12	$ 226,797	8.22%	12/11/2012	15.50	(20.00)	(4.50)	(0.37)
Total	**$ 2,760,011**	**100.00%**					**(4.25)**

Group Medical and Dental Claims

Table 32: Summary of Group Medical and Dental Claims Expenses

Delivery Period	Amounts	Weighting Factor %	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 1,125,344	8.37%	0.50	0.00	0.50	0.04
Feb-12	$ 1,052,741	7.97%	0.50	0.00	0.50	0.04
Mar-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Apr-12	$ 1,089,042	7.97%	0.50	0.00	0.50	0.04
May-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Jun-12	$ 1,089,042	8.37%	0.50	0.00	0.50	0.04
Jul-12	$ 1,125,344	8.37%	0.50	0.00	0.50	0.04
Aug-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Sep-12	$ 1,089,042	7.57%	0.50	0.00	0.50	0.04
Oct-12	$ 1,125,344	8.76%	0.50	0.00	0.50	0.04
Nov-12	$ 1,089,042	8.76%	0.50	0.00	0.50	0.04
Dec-12	$ 1,125,344	7.57%	0.50	0.00	0.50	0.04
Total	**$ 13,286,318**	**100.00%**				**0.50**

Long-term Disability

Table 33: Summary of Long-term Disability Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 193,181	8.94%	1/11/2012	15.50	(20.00)	(4.50)	(0.40)
Feb-12	$ 191,492	8.86%	2/11/2012	14.50	(18.00)	(3.50)	(0.31)
Mar-12	$ 190,374	8.81%	3/11/2012	15.50	(20.00)	(4.50)	(0.40)
Apr-12	$ 179,311	8.30%	4/11/2012	15.00	(19.00)	(4.00)	(0.33)
May-12	$ 177,478	8.21%	5/11/2012	15.50	(20.00)	(4.50)	(0.37)
Jun-12	$ 177,478	8.21%	6/11/2012	15.00	(19.00)	(4.00)	(0.33)
Jul-12	$ 176,332	8.16%	7/11/2012	15.50	(20.00)	(4.50)	(0.37)
Aug-12	$ 176,177	8.15%	8/11/2012	15.50	(20.00)	(4.50)	(0.37)
Sep-12	$ 175,007	8.10%	9/11/2012	15.00	(19.00)	(4.00)	(0.32)
Oct-12	$ 174,191	8.06%	10/11/2012	15.50	(20.00)	(4.50)	(0.36)
Nov-12	$ 174,702	8.08%	11/11/2012	15.00	(19.00)	(4.00)	(0.32)
Dec-12	$ 175,247	8.11%	12/11/2012	15.50	(20.00)	(4.50)	(0.36)
Total	**$ 2,160,971**	**100.00%**					**(4.25)**

Accidental Death and Dismemberment

Table 34: Summary of Accidental Death and Dismemberment Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 2,498	8.69%	1/11/2012	15.50	(20.00)	(4.50)	(0.39)
Feb-12	$ 2,440	8.49%	2/11/2012	14.50	(18.00)	(3.50)	(0.30)
Mar-12	$ 2,324	8.08%	3/11/2012	15.50	(20.00)	(4.50)	(0.36)
Apr-12	$ 2,376	8.27%	4/11/2012	15.00	(19.00)	(4.00)	(0.33)
May-12	$ 2,400	8.35%	5/11/2012	15.50	(20.00)	(4.50)	(0.38)
Jun-12	$ 2,374	8.26%	6/11/2012	15.00	(19.00)	(4.00)	(0.33)
Jul-12	$ 2,506	8.72%	7/11/2012	15.50	(20.00)	(4.50)	(0.39)
Aug-12	$ 2,356	8.20%	8/11/2012	15.50	(20.00)	(4.50)	(0.37)
Sep-12	$ 2,554	8.89%	9/11/2012	15.00	(19.00)	(4.00)	(0.36)
Oct-12	$ 2,302	8.01%	10/11/2012	15.50	(20.00)	(4.50)	(0.36)
Nov-12	$ 2,305	8.02%	11/11/2012	15.00	(19.00)	(4.00)	(0.32)
Dec-12	$ 2,310	8.04%	12/11/2012	15.50	(20.00)	(4.50)	(0.36)
Total	**$ 28,747**	**100.00%**					**(4.25)**

Employee Assistance Program

Table 35: Summary of Employee Assistance Program Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ -	0.00%	1/11/2012	15.50	(20.00)	(4.50)	0.00
Feb-12	$ 23,403	19.69%	2/11/2012	14.50	(18.00)	(3.50)	(0.69)
Mar-12	$ -	0.00%	3/11/2012	15.50	(20.00)	(4.50)	0.00
Apr-12	$ 17,756	14.94%	4/11/2012	15.00	(19.00)	(4.00)	(0.60)
May-12	$ -	0.00%	5/11/2012	15.50	(20.00)	(4.50)	0.00
Jun-12	$ 17,755	14.94%	6/11/2012	15.00	(19.00)	(4.00)	(0.60)
Jul-12	$ -	0.00%	7/11/2012	15.50	(20.00)	(4.50)	0.00
Aug-12	$ 19,328	16.26%	8/11/2012	15.50	(20.00)	(4.50)	(0.73)
Sep-12	$ 5,932	4.99%	9/11/2012	15.00	(19.00)	(4.00)	(0.20)
Oct-12	$ 19,234	16.18%	10/11/2012	15.50	(20.00)	(4.50)	(0.73)
Nov-12	$ 7,178	6.04%	11/11/2012	15.00	(19.00)	(4.00)	(0.24)
Dec-12	$ 8,284	6.97%	12/11/2012	15.50	(20.00)	(4.50)	(0.31)
Total	**$ 118,870**	**100.00%**					**(4.10)**

EHT

Table 36: Summary of EHT Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Dec-11	$ 256,358	8.09%	2/15/2012	7.00	39.05	46.05	3.73
Jan-12	$ 258,387	8.16%	3/15/2012	7.00	39.91	46.91	3.83
Feb-12	$ 257,282	8.12%	4/16/2012	7.00	43.94	50.94	4.14
Mar-12	$ 387,857	12.24%	4/16/2012	7.00	27.85	34.85	4.27
Apr-12	$ 251,921	7.95%	5/15/2012	7.00	32.48	39.48	3.14
May-12	$ 249,372	7.87%	6/15/2012	7.00	35.60	42.60	3.35
Jun-12	$ 248,825	7.86%	7/16/2012	7.00	37.95	44.95	3.53
Jul-12	$ 250,312	7.90%	8/15/2012	7.00	41.41	48.41	3.83
Aug-12	$ 246,973	7.80%	9/17/2012	7.00	30.03	37.03	2.89
Sep-12	$ 243,255	7.68%	10/15/2012	7.00	30.03	37.03	2.84
Oct-12	$ 245,346	7.75%	11/15/2012	7.00	32.87	39.87	3.09
Nov-12	$ 271,737	8.58%	12/17/2012	7.00	36.86	43.86	3.76
Total	**$ 3,167,626**	**100.00%**					**42.39**

NAVIGANT

WSIB

Table 37: Summary of WSIB Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan-12	$ 138,266	9.23%	2/28/2012	14.00	45.00	59.00	5.45
Feb-12	$ 139,473	9.31%	3/31/2012	14.00	49.00	63.00	5.87
Mar-12	$ 270,991	18.09%	4/30/2012	21.00	37.00	58.00	10.49
Apr-12	$ 132,178	8.82%	5/31/2012	14.00	40.00	54.00	4.76
May-12	$ 129,906	8.67%	6/30/2012	14.00	42.00	56.00	4.86
Jun-12	$ 129,136	8.62%	7/31/2012	14.00	45.00	59.00	5.09
Jul-12	$ 123,585	8.25%	8/31/2012	14.00	48.00	62.00	5.11
Aug-12	$ 165,653	11.06%	9/30/2012	21.00	36.00	57.00	6.30
Sep-12	$ 91,769	6.13%	10/31/2012	14.00	39.00	53.00	3.25
Oct-12	$ 77,282	5.16%	11/30/2012	14.00	41.00	55.00	2.84
Nov-12	$ 59,741	3.99%	12/31/2012	14.00	44.00	58.00	2.31
Dec-12	$ 40,083	2.68%	1/31/2013	14.00	47.00	61.00	1.63
Total	**$ 1,498,062**	**100.00%**					**57.96**

PILs Property Tax

Table 38: Summary of PILs Property Tax Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
2012	$ 36,310	67.43%	4/16/2012	183.00	(258.00)	(75.00)	(50.57)
2012	$ 17,541	32.57%	10/16/2012	183.00	(75.00)	108.00	35.18
Total	**$ 53,851**	**100.00%**					**(15.39)**

Property Tax

Table 39: Summary of Property Tax Expenses

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
2012	$ 1,064,974	16.53%	3/1/2012	183.00	(304.00)	(121.00)	(20.01)
2012	$ 1,064,869	16.53%	4/2/2012	183.00	(272.00)	(89.00)	(14.71)
2012	$ 1,064,792	16.53%	5/1/2012	183.00	(243.00)	(60.00)	(9.92)
2012	$ 1,082,192	16.80%	7/3/2012	183.00	(180.00)	3.00	0.50
2012	$ 1,082,063	16.80%	8/1/2012	183.00	(151.00)	32.00	5.38
2012	$ 1,081,952	16.80%	9/4/2012	183.00	(117.00)	66.00	11.09
Total	**$ 6,440,842**	**100.00%**					**(27.67)**

TREATMENT OF STRANDED ASSETS RELATED TO SMART METER DEPLOYMENT

In accordance with section 2.5.1.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) ("the Filing Requirements"), this schedule provides information about Toronto Hydro's proposed treatment of stranded assets related to smart meter deployment, which conforms with the guidance provided by the OEB in s. 2.5.1.4 of the Filing Requirements, and in section 3.7 and Appendix A-1 of the Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition (December 15, 2011). A completed copy of OEB Appendix 2-S is filed as Exhibit 2A, Tab 3, Schedule 2.

1. BACKGROUND

Toronto Hydro began its Smart Meter program in 2006 and substantially completed installation of all smart meters by the end of 2010. In 2012, Toronto Hydro applied for and was granted approval by the OEB for clearance of all remaining Smart Meter costs.[1]

2. NET BOOK VALUE ("NBV")

As of December 31, 2014, the net value of the Stranded Meters is estimated at $15.8 million. This value reflects the NBV of the assets ($16.3 million) less recovery amounts through scrap sales ($0.5 million). No carrying costs have been calculated on the Stranded Meter assets.

3. RECORDED AMOUNTS

For the conventional meters stranded through the Smart Meter program, Toronto Hydro continued to record these amounts in Account 1860 – Meters, until they were transferred

[1] EB-2013-0287, Decision and Order, January 16, 2014.

to Account 1555 – Sub-account Stranded Meter Costs in 2013. Depreciation was recorded on these meters since the beginning of the program.

4. RATE RIDER RECOVERY

For the purposes of 2015 Revenue Requirement (Exhibit 6, Tab 1, Schedule 1), the NBV of the stranded smart meter assets is not included in the utility's rate base. Toronto Hydro is seeking recovery of this amount through a separate rate rider. Toronto Hydro confirms that the associated recovery from the separate rate rider will be recorded in Account 1555 – Sub-account Stranded Meter Costs to reduce the balance of the sub-account.

For more information about the proposed rate rider, and an explanation of Toronto Hydro's approach to allocating the NBV of the stranded meters to the applicable customer rate classes, please refer to Exhibit 9, Tab 1, Schedule 1.

OEB Appendix 2-S
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)
2007	(2)	$ 67,097,235	$ 47,207,275		$ 19,889,960		$ 19,889,960
2008	(2)	$ 93,973,448	$ 68,107,443		$ 25,866,004		$ 25,866,004
2009	(2)	$ 103,875,474	$ 78,528,568		$ 25,346,906		$ 25,346,906
2010	(2)	$ 108,015,264	$ 84,895,573		$ 23,119,691		$ 23,119,691
2011	(2)	$ 109,231,835	$ 88,865,762		$ 20,366,073		$ 20,366,073
2012	(2)	$ 109,696,939	$ 92,049,602		$ 17,647,337		$ 17,647,337
2013	(2)	$ 121,654,750	$ 104,292,705		$ 17,362,045	$ 485,160	$ 16,876,884
2014	(1)(2)	$ 121,654,750	$ 105,377,923		$ 16,276,827	$ 485,160	$ 15,791,667

Notes:

(1) *For 2014 Deperication, it is provided based on forecast basis.*

(2) *For the period of 2007 to 2012, Stranded Meters were included in Account 1860. Stranded Meters were moved to Account 1555*

STREET LIGHTING ASSET TRANSFER

In two decisions relating to the utility's Street Lighting Transfer Application (EB-2009-0180 et al.), the OEB found that a portion of the street lighting assets in the City of Toronto can be considered distribution assets. In a Decision and Order dated February 11, 2010, the OEB made a principled determination about the categories of street lighting assets which could be considered to serve a distribution function and could be transferred to Toronto Hydro (the "Classification Decision"). In a subsequent Decision and Order, **/C** dated August 3, 2011, the OEB approved a value of $28.9 million of the assets that were **/C** found to be eligible to be transferred (the "Valuation Decision").

This schedule provides information to support Toronto Hydro's proposal to transfer former street lighting assets into the utility's rate base effective January 1, 2015, at the revised value of $39.8 million. Toronto Hydro submits that the revised transfer value of **/C** the street lighting assets has no effect on the utility's revenue requirement for all rate classes other than the Street Lighting and Unmetered Scattered Load ("USL") rate classes because the costs associated with the street lighting assets are directly allocated to the Streetlighting (95%) and the USL (5%) rate classes. For the Streetlighting class, these costs are offset by revenues from a Service Agreement with the City of Toronto. For the USL class, the effects are minimal. In addition, Toronto Hydro notes that for the purpose of this application, the effect of the proposed transfer has been fully integrated into the utility's operating and capital expenses, and cost allocation model; this schedule provides a summary of those effects.

The evidence is organized as follows:

1) Background
2) Post Filing Assessment **/C**
3) Asset Transfer Valuation

4) Summary of Capital and OM&A Programs relating to Street Lighting
5) Revenue Requirement and Cost Allocation

1. BACKGROUND

On June 15, 2009, Toronto Hydro together with Toronto Hydro Energy Services Inc. ("TH Energy") and related legal entities (collectively, the "Applicants") applied jointly to the OEB for authorization to effectively transfer the streetlighting and expressway lighting assets held by TH Energy to Toronto Hydro.

In the Classification Decision, the OEB found that only certain assets are appropriately considered distribution assets (based on purpose, functionality, or intended use) and are eligible to be transferred to Toronto Hydro. Essentially, the OEB found that assets which are dedicated only to the streetlighting function *per se* (including luminaires, brackets and conductors on the bracket, and poles, related pole foundations and conductors along poles on local roads fed by underground circuits) did not serve a distribution function, and therefore were ineligible to be transferred. However, other assets (including poles, related pole foundations and conductors fed by overhead distribution lines or by underground circuits in mixed use urban areas) were found to have, or be capable of having, a distribution function. These assets were eligible to be transferred, as were underground conductors in residential areas, and all handwells that formed part of the street lighting system.

In the Classification Decision, the OEB rejected, for regulatory purposes, the discounted cash flow valuation that underpinned the original purchase of the street lighting assets by TH Energy from the City of Toronto in 2006, and found that the depreciated historic cost ("DHC") method was more appropriate for rate setting purposes. However, as described in the Applicant's evidence and acknowledged by the OEB in the Valuation Decision, /C

DHC information on the existing street lighting assets did not exist and was too costly to /C create.[1] The OEB therefore directed Toronto Hydro to bring forward further evidence enumerating the assets that were eligible for transfer according to the principles and categories set out in the Classification Decision, and provide a "physical valuation" of those assets.[2]

In addition, the OEB found that it was unable to determine on the evidence the proper classification of expressway lighting. The Applicants subsequently withdrew their request for the transfer of the expressway lighting assets in light of the principles set out in the Classification Decision. /C

In response to the Classification Decision, Toronto Hydro and TH Energy undertook two studies. The first was an exhaustive cataloguing of the streetlighting (and expressway lighting) assets, carried out by their staff and contract resources. This cataloguing (the "Inventory Study") recorded asset locations, condition, and other parameters (including /C street type with respect to type of supply) necessary to properly classify the assets according to the terms of the Classification Decision. Toronto Hydro then used the data /C collected in the Inventory Study to determine the classification of all individual assets according to the criteria set out in the Classification Decision.-

The second study was a valuation study conducted by ValuQuest Limited (the "ValuQuest Study"), which used the Depreciated Replacement Cost ("DRC") method to provide a "physical valuation" of the assets based on information from the Inventory Study. The ValuQuest Study found a DRC value of $83.7 million for the streetlighting /C assets, and $99.1 million for the total of streetlighting and expressway lighting assets.

[1] Valuation Decision, at page 14. The information does exist for assets installed after the purchase.
[2] Classification Decision, at page 20. /C

The Applicants filed evidence including the ValuQuest Study on January 31, 2011 in response to the OEB's direction in the Classification Decision. The Applicants proposed a 2010 year end valuation for the transferred assets of $28.9 million. This value was arrived at by scaling the DRC amounts in each asset class by the ratio of the 2010 year-end total net book value ("NBV") of $63.5 million. TH Energy's financial records the DRC total of $99.1 million. The basis of this valuation is explained in further detail below. **/C** **/C**

In the Valuation Decision, the OEB accepted the figure of $28.9 million as the 2010 year-end value of the transferable assets; however, the OEB noted that it did not specifically endorse the scaling of the DRC values so that their total matched the 2010 year-end NBV value. The OEB decided that rate base, revenue requirement, and rate consequences of the transfer would be determined in Toronto Hydro's next cost of service application.[4] **/C**

On November 7, 2011, Toronto Hydro filed evidence in its EB-2011-0144 cost of service application relating to the incorporation of the street lighting assets into the utility's rate base.[5] In that application Toronto Hydro proposed a slightly lower transfer price for the assets of $28.5 million, reflecting the forecast evolution of the assets (principally additions and depreciation) over 2011. However, the OEB ultimately dismissed the EB-2011-0144 application so the matter remained unresolved. **/C** **/C**

The Applicants proceeded as authorized by the OEB to complete the transaction effective January 1, 2012. At that time an Agreement of Purchase and Sale (the "Sale Agreement") was executed between the parties which initially provided for a transfer price of $28.5 million, subject to a detailed analysis of the NBV of the transferred assets, which analysis would then underpin an adjustment to the transfer price, if necessary. **/C**

[4] Valuation Decision, at page 15.
[5] EB-2011-0144, Application and Evidence, Exhibit P3 (November 7, 2011).

By February of 2012, Toronto Hydro and TH Energy completed the detailed analysis of the NBV of the transferred assets, and found that the true NBV of the transferred assets was in fact $44.2 million. The methodology of the detailed analysis is explained in detail below. As a result, the value of the assets transferred was recorded at $44.2 million in Toronto Hydro's books. There was no change to the total valuation of the combined streetlighting and expressway lighting assets, so the amount that remained un-transferred in TH Energy was correspondingly lower. **/C**

2. POST FILING ASSESSMENT

Toronto Hydro filed a previous version of this evidence on July 31, 2014. After the filing, Toronto Hydro conducted an assessment of the assumptions and methodology underlying the transfer, and determined that evidence must be revised. The revised description below does not affect the proposed value of the asset transfer into Toronto Hydro's rate base.

Toronto Hydro determined that an additional data point was used in the detailed analysis of the NBV of the transferred assets. This data point was the Optimal Investment Portfolio ("OIP") study, which was conducted in 2004 to assess the vintages of all major assets in Toronto Hydro's system, and to implement IFRS-consistent changes related to the manner in which Toronto Hydro records and accounts for its assets. For the purpose of the street lighting transfer, the OIP Study was used to determine the vintages of the poles, pole foundations and handwells and to allocate these assets between Toronto Hydro and TH Energy. The OIP Study provided better information about the vintages of the street lighting assets than the Inventory Study which was used for the purpose of the Valuation Decision in 2011. To illustrate, the original valuation assumed that approximately 49% of poles which did not have an associated year, were fully **/C** depreciated. The OIP Study, however, revealed that only 5% of poles were without an associated year. Similarly, the original valuation assumed that nearly 58% of poles were older than 1970 and were thus fully depreciated, but the OIP Study shows that there were less than half of this number of poles, approximately 27% of poles, in that vintage band. [6]

In addition, Toronto Hydro assessed the classification of assets into the transferable and non-transferable categories and determined that: 1) approximately 5900 poles and related assets transferred from TH Energy were not *prima facie* eligible to be transferred because they were located on local streets fed by underground supply; and 2) some handwells, namely those associated with poles that were not transferable from TH Energy, were not transferred to Toronto Hydro, as required by the OEB decision. The revenue requirement impact of these findings is estimated to be $0.2 million. Because the impact of the reassessment is significantly lower than the utility's materiality threshold of $1 million, Toronto Hydro has not updated the value of the assets that it proposes to transfer. For greater certainty, the utility confirms the reassessment does not adversely affect any of the utility's rate classes. For the Streetlighting class, the incremental costs would be offset by revenues from a Service Agreement with the City of Toronto. For the USL class, the effects are minimal, as only 5% of the costs are allocated to this class of customers.

PricewaterhouseCoopers LLP ("PWC") was retained to review and provide an independent assessment of the methodology used by Toronto Hydro to arrive at the revised transfer price of the street lighting assets. PWC issued a report on July 28, 2014, which was filed alongside the original version of this evidence on July 31, 2014. PWC has considered the changes to original evidence, and has issued an addendum to its report with respect to the noted revisions. The addendum is filed at Exhibit 2A, Tab 5, Schedule 2, Appendix A.

/C

3. ASSET TRANSFER VALUE

For purposes of the present application, Toronto Hydro requests OEB approval to transfer the former streetlighting assets into the utility's rate base at a value of $39.8 million, **/C** which represents the opening net book value of the assets in 2015. This amount reflects the actual cost incurred by Toronto Hydro to acquire the 2012 transferred assets from TH Energy, the additional assets that were put into service in the intervening period (i.e., 2012 to 2014), as well as depreciation on all assets. A stepwise explanation of the **/C** derivation of this amount is set out below.

3.1. The Need For A Detailed Analysis Of The Transferred Assets

Several factors contributed to the need to perform a detailed analysis of the NBV of the transferred assets. First, accounting and financial reporting standards require Toronto Hydro to maintain its financial records in a manner that permits accurate recording of assets owned by the respective businesses and depreciation on those assets. In order to calculate depreciation, the companies must have accurate records of the vintage of their assets and of the remaining useful lives of those assets in cases where acquired assets are not new.

Given the structure and function of the fixed asset sub-ledgers of both companies, it was not possible from an accounting perspective to simply transfer an unassociated amount between the companies without linking that amount as closely as possible to the underlying assets. Doing so would have interfered with the process of recording depreciation on the remaining assets, as Toronto Hydro would have no way of calculating depreciation for different asset types and vintages based on a single unassociated value being transferred to it. Therefore, it was necessary to perform the detailed analysis outlined below in order to identify the types, quantities, and vintages of the assets being transferred from TH Energy to Toronto Hydro.

Second, as explained in further detail below, the definitions of asset classes differed between TH Energy's s fixed asset sub-ledger and the ValuQuest Study. The ValuQuest Study distinguished poles, pole foundations, and handwells, whereas TH Energy's fixed asset sub-ledger considered those to be one asset class. Conversely, TH Energy's fixed asset sub-ledger distinguished underground from overhead conductors, while the ValuQuest Study did not. Since some poles were associated with either, or both of, foundations and handwells, while others were not, this meant that a detailed analysis was required to effectively disaggregate the pole asset class in TH Energy's fixed asset sub-ledger in order to properly reflect the assets that were transferred. Allocations were also required for other asset classes.

Third, while Toronto Hydro accepted the principles of asset classification set forth by the OEB in the Classification Decision, the fact remained that those principles did not correspond to the financial records associated with the assets. For the assets that were found to be eligible for transfer, no existing asset classes exclusively and exhaustively represented the assets that could be transferred. As mentioned above, TH Energy's financial records considered handwells, poles and pole foundation to be one asset class, whereas the OEB's Valuation Decision found that while all handwells could be transferred, only certain poles and poles foundation were eligible. Therefore, a detailed analysis was required to properly separate the assets that were eligible for transfer, according to the criteria set out by the OEB in the Classification and Valuation Decisions.

3.2. Initial Conditions for the Detailed Analysis

In late 2011 and early 2012, following the preparation of the evidence in EB-2011-0144, Toronto Hydro undertook the detailed analysis of plant records for the purpose of supporting the asset transfer. At that time, Toronto Hydro had available to it the following information:

- The initial 2006 purchase price for sale of the City of Toronto-owned streetlighting and expressway lighting assets to TH Energy of $60 million. This amount was subsequently recognized on TH Energy's books as the sum of amounts in five asset classes (poles, towers and fixtures; overhead distribution lines and feeders; underground conduit; underground distribution lines and feeders; and streetlight fixtures and luminaires).
- The continuity (additions and depreciation) for the assets originally acquired from the City of Toronto (the "originally acquired assets"), as well as the assets added from the date of the purchase (2006) to the end of 2011. However, TH Energy's fixed asset sub-ledger did not contain information on the location of any assets, and did not contain information on the vintage of the originally acquired assets.
- The Inventory Study database, containing information on all of the streetlighting (and expressway lighting) assets, including condition, and situation (i.e., location on distinguished street types in accordance with the Classification Decision). **/C**
- The GEAR (Geo-Spatially Enabled Asset Registry) database, which was used by the Inventory Study, and which associated a Feature Identification ("FID") Number and vintage information with each pole asset where available. **/C**
- The ValuQuest Study and related database.
- The Optimal Investment Portfolio ("OIP") Study that was conducted in 2004 to assess the vintages of all major assets in Toronto Hydro's system. **/C**
- The Sale Agreement, dated December 29, 2011.

3.3. Detailed Analysis of the Originally Acquired Pole Assets

In order to bring TH Energy's fixed asset sub-ledger vintage information on the originally acquired assets to a level comparable to that of the subsequently installed assets, Toronto Hydro used information in the Inventory Study to determine which pole assets were transferrable and to stratify the originally acquired pole assets into vintage bands. For example, TH Energy had a count of poles by 5-year vintage bands starting in **/C**

1971 and ending in 2005. (Vintage bands were designated by their mid-points, so that the 1971 – 1975 vintage band was designated 1973.) The useful life of pole assets was set at 40 years, so assets installed prior to 1972 were considered to be fully depreciated.

Location information for pole foundations and handwells was matched to location information for poles to associate those assets with the corresponding poles. As previously noted, not all poles were associated with foundations or handwells, while some poles were associated with either or both of foundations and handwells.

In 2006, the originally acquired assets were classified into five assets classes and were assigned estimated remaining useful lives. For financial statement purposes, poles, pole foundations and handwells were merged into one asset class, “poles”.

In 2011, subsequent to the release of the Inventory Study, in which poles were stratified into eleven 5-year vintage bands TH Energy assessed the need to prospectively change the remaining useful lives of poles to reflect the new information. Hence in 2011, the originally acquired pole asset in the financial records was stratified according to the vintage bands as per the Inventory Study. To do this, TH Energy applied standard costs of poles from the ValuQuest Study, which was approximately $2,340.00.

For the purpose of applying standard cost to historical quantities, TH Energy deflated the pole standard costs by the CPI (2010=100) to the mid-points of each vintage to arrive at sets of deflated standard costs for each vintage band. The resulting figures are essentially estimates of, or proxies for, the unit gross acquisition costs for each vintage band, which TH Energy was required to use in the absence of information on actual historical acquisition costs.

/C

The last element to disaggregate the asset within vintage bands was to scale the results so that the sum of the initial disaggregated NBV by vintage to agree with the amounts carried in TH Energy's books at the end of 2010. To do so, the accumulated depreciated was allocated proportionally to the vintage bands.[7] In order to arrive at the NBV at the end of 2011, it was then necessary to compute and deduct from the proxy acquisition costs the corresponding derived accumulated depreciation.

As previously noted, Toronto Hydro had conducted an analysis of the Inventory Study database to determine which poles and related assets were transferable, and to stratify the acquired assets by vintage bands. The OIP Study was then used to determine the vintage of the pole assets eligible for transfer and to allocate pole assets between Toronto Hydro and TH Energy. A recalculation – based on the OIP Study – of the stratification of the originally acquired pole assets was completed and deemed immaterially different (less than $150,000). Therefore, although the OIP provided better information about the age of the assets than was available from the Inventory Study, Toronto Hydro determined that it was not necessary to restate the stratification of the acquired assets. **/C**

If a foundation or handwell was associated with the pole, they were assumed to be of the same vintage. With this information, Toronto Hydro was able to compile a list by vintage of the poles, foundations and hand wells to be transferred.[8] The counts by vintage and type of each asset to be transferred were then divided by the corresponding total asset counts in each vintage, and multiplied by the corresponding adjusted NBVs to obtain the transferred NBV by vintage for all asset types. Using illustrative data, the

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[7] Due to the prospective treatment of the change in remaining useful life of the pole assets, it was not necessary to stratify the accumulated depreciation as the acquired assets at the close of December 31, 2010 were pooled and shared the same remaining useful life.
[8] As mentioned above in section 2, Toronto Hydro conducted an assessment and determined that a number of handwells were not transferred from TH Energy, as required by the OEB decision. Toronto Hydro has not updated the value of the transferred assets because the revenue requirement impact is immaterial.

process of determining the transferable proportion of each vintage's NBV by class is depicted in Table 4 below.

Table 1: Illustrative Determination of Asset Vintage NBV Proportion Transferred

		Transferred Assets			All Assets			Proportion of Asset Vintage NBV Transferred		
Vintage	Asset FID	Pole Count	Found. Count	Handw. Count	Pole Count	Found. Count	Handw. Count	Poles	Found's	Handw's
2003	1234567	1		1						
	2658976	1	1	1						
	1359678	1		1						
	3698647	1								
SubTotal		4	1	3	7	5	3	0.5714	0.2000	1.0000
1998	2345678	1								
	4563985	1	1	1						
	3547851	1		1						
	2569864	1		1						
	4263587	1	1	1						
	3652698	1								
SubTotal		6	2	4	11	5	4	0.5455	0.4000	1.0000
1993	3456789	1	1							
	4785692	1	1	1						
	2135689	1								
	1245785	1	1							
	3625634	1		1						
SubTotal		5	3	2	9	7	2	0.5556	0.4286	1.0000
...										
1973	9876543	1	1							
	5698632	1		1						
SubTotal		2	1	1	5	2	1	0.4000	0.5000	1.0000

/C

This example illustrates that the poles, which are the 'anchor' assets, may be associated with foundations, handwells, both, or neither. The pole FID enables that association to be made. In the result, there is no constant relationship or proportionality within or across vintages between poles and the other assets. In order to properly execute the transfer of only the authorized assets, it was necessary to perform the detailed analysis to establish what other assets were associated with the transferable poles, and properly value the entire transferred asset base. While it is possible after the fact of the analysis to calculate the proportion of the transferred assets by class, it is not possible to proceed in the opposite direction to infer from a simple proportion what assets from what class and vintage are properly transferable. /C

With respect to the balance of the assets in TH Energy's "Poles" asset class installed after the 2006 asset acquisition from the City, the process of determining the transferable proportion of NBV by vintage was the same. However, because of the detailed records then being kept, it was not necessary to go through the stratification process, and the "vintages" in the post-acquisition period were individual years.

3.4. Determination of the Transferred Proportions of Other Assets

Several other asset classes were also transferable according to the Classification Decision. These included overhead and underground conductors, and conduits, but did not include conductors within untransferred streetlight poles and brackets. In addition, since Toronto Hydro withdrew its request to transfer any expressway lighting assets, all conductors and conduits associated with expressway lighting were excluded.

In the case of conductors, conduits, and ducts, there were again differences in classification as between the ValuQuest Study and TH Energy's fixed asset sub-ledger. The ValuQuest Study identified only conductors for the streetlighting assets, and conductors and conduit for expressway lighting assets. In comparison, TH Energy's fixed asset sub-ledger classified these assets as underground conduit, underground distribution lines and feeders, and overhead distribution lines and feeders.

With the information available to it, Toronto Hydro was not able to specifically separate in the fixed asset sub-ledge these secondary assets based on location in the fixed asset sub-ledger. Therefore, Toronto Hydro relied on information presented to the OEB at the time of the Valuation Decision, specifically that shown in 'Table 4: Derivation of NBV by Asset Group and Classification', on page 19 of that evidence.[9] In that evidence, the Group NBV figures represented the Group DRC values found by ValuQuest, scaled down by approximately 36% such that their total would be equal to the then current total NBV on TH Energy's books. Toronto Hydro summed the "Group NBV" figures for streetlighting conductors, and expressway lighting conductors and conduits and considered those groups to be equivalent to the TH Energy asset classes of underground conduit, underground distribution lines and feeders, and overhead distribution lines and feeders. /C

The total Group NBV for those three asset classes was $4.7 million, of which streetlighting conductors represented $3.6 million, or 76.65%. Expressway conductors and conduit, which were categorically excluded, represented the balance. Toronto Hydro then multiplied the streetlighting conductor percentage by the percentage of transferable streetlighting conductors, 64.62%, which latter percentage was based on Toronto Hydro's physical classification of assets into the transferable and non-transferable categories. The product of the percentages (76.65% * 64.62%) is 49.53%. On this basis, Toronto Hydro determined that 49.53% of the total NBV of TH Energy's asset classes of underground conduit, underground distribution lines and feeders, and overhead distribution lines and feeders would be transferred to Toronto Hydro. For the assets transferred to Toronto Hydro on January 1, 2012, this amount was $7.281 million. /C

[9] EB-2009-0180 et. al, Application and Evidence (January 31, 2011) at page 19 of 21. /C

3.5. Determination of the Transferred Proportion of CWIP

At any point in time, there is a balance in the Construction Work in Progress (“CWIP”) account. In the case of TH Energy’s street lighting assets, a CWIP balance of $6.265 million at December 31, 2011 existed, but it was not possible to specifically trace that balance to transferable versus non-transferable assets. As an interim proxy, the transferred proportion of in-service streetlighting assets (68%) was applied to the then existing CWIP balance to divide that balance between Toronto Hydro and TH Energy. Toronto Hydro’s assumed share of the CWIP balance was therefore $4.264 million.

For that purpose, a “top-sided” entry was made to show the transfer of the portion of CWIP to Toronto Hydro. In the intervening years from 2012 to the current time, as projects were closed to net fixed assets, they were recorded in the books of TH Energy or Toronto Hydro as appropriate and any necessary adjustments were made to the top-sided entry to reflect any variance from the assumed proportion of 68%, and to draw down that balance as projects were closed. The closure of projects to Toronto Hydro’s net fixed assets is reflected in the asset continuity tables set out below.

3.6. Summary of the Assets Transferred as of January 1, 2012

The assets were transferred to Toronto Hydro in the same asset classes as they existed in TH Energy’s books, and were distinguished by asset class and vintage. For example, poles, foundations, and handwells of the 1988 vintage were transferred to Toronto Hydro as an asset designated “1988 Poles”.

The incurred cost to Toronto Hydro upon transfer was treated as Toronto Hydro’s gross acquisition cost of the assets, and accumulated depreciation at the time of transfer was zero in all cases. However, to recognize the fact that a variable portion of the useful lives of the assets had elapsed for the majority of the assets, the remaining useful life was determinative of the rate of depreciation subsequently applied to the assets.

The useful lives of all assets except Conduits were set at 40 years, with Conduits set at 50 years. The remaining useful life figures for each vintage of asset were calculated based on the useful lives and the vintages of the assets. As an example, a 1973 pole with a useful life of 40 years had at the end of 2011 a remaining useful life of two years. Although the 1973 vintage notionally included the year 1971, all assets (in this case, only poles) installed in 1971 or earlier were deemed to be fully depreciated and none were transferred at any value to Toronto Hydro.

Because of the deferral of the ratemaking treatment of the transferred assets, the utility determine that it was necessary, as a temporary measure, to record the transferred assets along with other non-rate regulated portions of Toronto Hydro's business (i.e., Conservation and Demand Management and eligible generation). Had the transferred assets been recorded in Toronto Hydro's rate-regulated financial records along with other fixed assets that are part of the utility's rate base, it would have been impossible, practically, to separately track the assets and their evolution over the period until the rate making treatment was established. In this Application, Toronto Hydro proposes to transfer the street lighting assets to the utility's Property, Plant and Equipment ("PP&E") fixed asset register.

3.7. Summary of the Continuity of Assets: 2012 to 2014

Over the period from the beginning of 2012 to the (forecast) end of 2014, Toronto Hydro has added assets and has similarly recognized depreciation on all the assets that it acquired effective January 1, 2012. For all the assets added since January 1, 2012, Toronto Hydro has the normal and exact information on gross book value, accumulated depreciation, and net book value.

3.8. Explanation of Variance in Asset Valuation

The overall variance between the proposed 2014 year end NBV of the former street lighting assets ($39.8 million) and the original amount approved by the OEB in the Valuation Decision ($28.9 million) is composed of normal asset evolution amounts occurring over the period January 1, 2011 to December 31, 2014, and the difference in valuation amounts for the transferred assets.

The Valuation Decision amount was based on 2010 year-end figures, while the January 1, 2012 transfer amount was based on 2011 year-end figures. Therefore, some part of the difference between the two is due to asset evolution over 2011. Since a Valuation Decision amount based on 2011 year-end figures does not exist, it is not possible to precisely quantify what the difference would be between that (hypothetical) amount and the transfer amount. Nevertheless, the bulk of the variance is due to factors other than asset evolution over 2011.

These factors stem from a data and information gap at the time of the Valuation Application and Decision. Toronto Hydro fully acknowledges the valuable information provided through the Inventory Study and the ValuQuest Study. However, it is still the case that the proxy value of $28.9 million provided at the time was the result of two simplifying assumptions that had to be made due to the lack of more precise information. The first was that the values of the transferred assets were proportional to their counts, which is effectively the same as assuming that all individual assets within a class are of equal value regardless of their vintage and composition. The detailed analysis revealed new information indicating that assumption was not valid in the case of the streetlighting asset transfer.

The OIP Study, which was used to allocate the pole assets between Toronto Hydro and TH Energy, provided more accurate and complete information about the age of the assets than was available in Toronto Hydro's geospatial asset registry ("GEAR") system at the time of the Inventory Study and the Valuation Application. /C

The second assumption was that the proportions of the total asset represented by the various asset classes in both the TH Energy fixed asset sub-ledger and the ValuQuest Study were (approximately) equivalent. However, because of the differences in asset classifications, it was not evident prior to the detailed analysis whether this was valid, and upon that analysis, some significant differences became apparent.

In combination, these factors led to variances caused both by differences in the percentages of assets transferred on a class by class basis, and by differences in the initial NBVs by class, as between TH Energy's fixed asset sub-ledger and the ValuQuest Study amounts, which after being prorated downward underpinned the Valuation Decision amount of $28.9 million. In addition, the ValuQuest Study did not take into account /C
CWIP, a portion of which was transferred as explained above.

It was necessary for Toronto Hydro to perform the detailed analysis resulting in the revised valuation in order to properly implement the OEB's Valuation Decision, and provide an accurate basis for Toronto Hydro's and TH Energy's ongoing accounting and financial reporting obligations. No existing asset classes exclusively and exhaustively represented the assets eligible for transfer; instead, the transferable assets were co-mingled with non-transferable assets. Therefore, it was necessary for example to disaggregate the existing TH-Energy class of 'poles' into its components of poles, foundations, and handwells, in order to extract the transferrable assets together with their corresponding values. Furthermore, since depreciation accounting depends on asset vintages and depreciation rates, it was not possible to simply transfer an amount unassociated with asset types and vintages, since by doing so the information required for ongoing accounting would have been lost.

The detailed analysis created new information pertaining specifically to the transferred assets that was not available at the time the Valuation Application was submitted or the Valuation Decision was rendered. The new information, resulting from the detailed analysis, provides a better proxy for the Depreciated Historic Cost of the transferred assets than does the Depreciated Replacement Cost approach, with its results scaled down to match the then existing asset value carried on TH Energy's books. This is because the detailed analysis specifically traces the vintage and remaining useful life of the transferred assets, rather than simply assuming that all assets of a particular type were of equal value, regardless of vintage. However, the detailed analysis does not increase the value of the overall asset; rather, it changes the proportion of the unchanged total amount that is transferred to Toronto Hydro.

/C

4. SUMMARY OF CAPITAL AND OM&A PROGRAMS

In its decision authorizing the transfer of certain former street lighting assets into Toronto Hydro's Distribution system, the OEB determined that these transferred assets are effectively distribution assets. As such, these former transferred street lighting assets will be managed through Toronto Hydro's core distribution capital and maintenance programs, as described in Exhibit 2B, Section E6 and Exhibit 4A, Tab 2, respectively.

4.1. Capital Programs

Three of Toronto Hydro's capital programs are relevant to the replacement of the transferred assets when those assets reach the end of their lives. These programs are:

- **Overhead Circuit Renewal** (Exhibit 2B, E6.4), which funds the replacement of overhead assets such as poles and conductor on a planned basis;
- **Underground Circuit Renewal** (Exhibit 2B, E6.1),which funds the replacement of underground cables and conductor on a planned basis; and

- **Reactive Capital** (Exhibit 2B, E6.20), which funds the replacement of both overhead and underground assets on an unplanned and non-discretionary basis to restore functionality or mitigate an unsafe condition due to asset degradation, damage, or failure.

The sub-set of capital expenditures under each of these programs associated with the transferred assets are summarized in Table 2 below. **/C**

Table 2: Capital Expenditures Associated with Transferred Assets ($ millions) **/C**

Capital Program	2015	2016	2017	2018	2019
Overhead Circuit Renewal	1.9	2.1	2.5	2.3	1.5
Underground Circuit Renewal	0.4	0.4	0.3	0.4	0.5
Reactive Capital	0.4	0.4	0.4	0.4	0.4
TOTAL	**2.7**	**2.9**	**3.2**	**3.1**	**2.4**

4.2. Operations and Maintenance Programs

Four of Toronto Hydro's maintenance programs are applicable to the transferred assets. These programs are:

- **Preventative & Predictive Maintenance** (Exhibit 4A, Tab 2, Schedule 1), specifically the Line Patrols and Pole Inspections Segment, assesses the structural integrity of transferred street lighting poles and identifies deficiencies with overhead plant that may raise unacceptable safety and system reliability risks;
- **Corrective Maintenance** (Exhibit 4A, Tab 2, Schedule 2), undertakes the permanent repair and remediation of overhead and underground assets such as conductors and cables that have deteriorated or are defective as identified during

the normal course of operations (e.g., Line Patrols and Pole Inspections);

- **Emergency Maintenance** (Exhibit 4A, Tab 2, Schedule 3), specifically the Grid Response or Significant System Disturbance Segment, responds to emergency conditions such as downed conductors, imminent asset failures, and situations that pose significant safety risks; and
- **Customer-Driven Work** (Exhibit 4A, Tab 2, Schedule 7), specifically the Damage Prevention Segment, conducts cable locating upon request from property owners and contractors.

The sub-set of operational expenditures under each of these programs associated with the transferred assets are summarized in Table 3 below. **/C**

Table 3: Operational Expenditures Associated with Transferred Assets ($ millions) **/C**

Operational Program	2015
Preventative & Predictive Maintenance	0.1
Corrective Maintenance	1.6
Emergency Maintenance	0.2
Customer-Driven Work	1.7
TOTAL	3.7

5. REVENUE REQUIREMENT AND COST ALLOCATION

The revenue requirement consequences of the utility's proposal to incorporate the street lighting assets into the utility's rate base effective January 1, 2015 are summarized in Table 4 below. **/C**

Table 4: Revenue Requirement from Streetlighting Assets ($ millions) /C

Revenue Requirement Component	2015 Test Year	
NBV of Assets – opening	39.8	
NBV of Assets – closing	39.1	
Average NBV	39.5	
Working Capital Allowance	0.2	
Streetlighting Ratebase	**39.7**	
OM&A	3.7	
Cost of Capital	2.5	
Depreciation	1.6	
PILS	0.3	/C
Service Revenue Requirement	**8.1**	/C
Revenue Offset – Contract Revenue	8.1	/C
Base Revenue Requirement	**0.0**	

5.1. Revenue Offset

Under existing agreements between TH Energy and the City of Toronto, TH Energy receives service fees for the maintenance and operation of the street lighting assets. Given the transfer of a portion of these assets into Toronto Hydro's rate base as distribution assets, Toronto Hydro proposes to allocate a portion of the revenue that it expects to receive to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

5.2. Cost Allocation

For the purposes of Cost Allocation, Toronto Hydro has allocated all of the costs associated with the transfer of the street lighting assets to a combination of the Street lighting rate class and the Unmetered Scattered Load ("USL") rate class. No other rate class is affected by the transfer. This is the same treatment proposed by Toronto Hydro in the Streetlighting Transfer Application.

Between the two classes – Streetlighting and USL – the additional costs related to the transfer were allocated 95% / 5% to these classes, respectively. USL attracts some of the costs as the assets being transferred have in some cases served USL loads. Toronto Hydro's best estimate, based on informed judgment, is that 5% is a reasonable allocation to this class.

The revenue offset of $8.1 million is however allocated 100% to the Streetlighting class. **/C**
Toronto Hydro submits that this is an appropriate allocation because the revenue offset is based on the contract with the City of Toronto to service the street lighting assets.

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Toronto Hydro Street Lighting Assets

Assessment of the valuation methodology used by Toronto Hydro in EB-2014-0116

July 28, 2014

pwc

Contents

Assignment, Scope and Background

Assignment

1. Toronto Hydro Electric Systems Inc. ("THESL"), Toronto Hydro Energy Services Inc. ("THESI"), and 1798594 Ontario Inc. ("NewCo"), are all wholly owned subsidiaries of Toronto Hydro Corporation ("Toronto Hydro" or "the Company"). The City of Toronto ("the City") is Toronto Hydro's sole shareholder.

2. THESL owns and operates an electricity distribution system which delivers electricity to approximately 730,000 customers located in the City of Toronto. It is the largest municipal electricity distribution company in Canada and distributes approximately 19% of the electricity consumed in Ontario.

3. THESL is regulated by the Ontario Energy Board ("OEB") which regulates the province's electricity and natural gas sectors in the public interest.

4. THESL has filed a proposed rate application (EB-2014-0116) with the OEB which includes a revised purchase price for certain street lighting assets which THESL purchased from its unregulated affiliate, THESI on January 1, 2012 (the "Current Proposal"). Please refer to the background section of this report for further information on the original application and sequence of transactions.

5. Tory's LLP has engaged us, PricewaterhouseCoopers LLP ("PwC", "us" or "we"), to prepare a report to be used as evidence in the Current Proposal.

6. This report was prepared for the purpose of the rate application (EB-2014-0116) relating to the proposed 2015 distribution rates. Specifically, we have been asked to provide our opinion on the following two questions:

   1) Is the revised detailed analysis prepared by Toronto Hydro of the value of former street lighting assets to be included in rate base determined using a reasonable method of calculating the depreciated historical cost of such assets?

2) Does the revised method used to value the former street lighting assets provide a better proxy for the depreciated historic cost of the assets than was provided to the OEB at the time of the August 2011 decision?

7. This report has been prepared by Ken Goodwin to best of his knowledge, acting independently and objectively. A copy of Mr. Goodwin's credentials have been attached as Appendix A.

Scope

8. In preparing our report, we have reviewed relevant documents and relied upon their accuracy and completeness, including the following:

- "Toronto Hydro Corporation – Street & Expressway Lighting Network – Estimate of Fair Market Value" prepared by Deloitte as at October 31, 2005;
- OEB decision and orders dated February 11, 2010 (the "February Decision") and August 3, 2011 EB 2009-0180, EB 2009-0181, EB 2009-0182 and EB 2009-0183; (the "August Decision")
- Additional evidence filed in EB 2009-0180, EB 2009-0181, EB 2009-0182 and EB 2009-0183 on January 31, 2011;
- "Allocation of Street Lighting Assets for the Purpose of the Asset Transfer in 2011/2012" Provided by: Toronto Hydro to PWC on July 12, 2014;
- Amended and Restated Asset Purchase Agreement between 1798594 Ontario Inc. and Toronto Hydro Energy Services Inc. (executed December 29, 2011);
- Revised Purchase and Sale Agreement (with updated price) between THESI and THESL (dated October 10, 2012);
- ValuQuest Street Lighting and Expressway Lighting Assets Valuation Report for Toronto Hydro-Electric System Ltd. and 1798594 Ontario Inc. as at November 1, 2010 (Issued December 1, 2010) (the ValuQuest Study);
- Kinectrics Inc. Report No: K-418021-RA-0001-R002 – Toronto Hydro Electric System Useful Life of Assets (dated August 28, 2009); and
- Interviews and discussions with Toronto Hydro management.

Background

9. We understand that all of the City's street lighting assets were sold to THESL's unregulated affiliate THESI, at a purchase price of $60 million in December 2006 (the "Acquired Assets"). We further understand that this purchase price was arrived at using a discounted cash flow analysis.

10. In 2009, three Toronto Hydro subsidiaries, THESL, THESI and NewCo filed applications with the OEB seeking approval for the Acquired Assets to be included in THESL's distribution system as defined by the *Ontario Energy Board Act, 1998, S.O. 1998, c.15 (schedule B)* (the "Act"). The applications collectively sought a declaration by the Board that streetlighting assets owned by THESI in the City of Toronto (the "SEL System Assets"), are deemed to be a distribution system and, ultimately, to make those assets part of a new amalgamated distribution company consisting of THESL and NewCo.

11. The OEB issued a decision in February 2010[1] (the "February Decision") which stated that THESL may only transfer street light assets which can be specifically identified as assets which are used to convey electricity at voltages of 50 kilovolts or less and meeting the specific criteria as set out in the February Decision (the "Distribution Assets"). The OEB also stated that that a valuation must be provided supporting the value of the Distribution Assets.

12. In January 2011, THESL submitted evidence[2] to respond to the OEB's request (the "Additional Evidence" or the "Original Application"). The evidence included an enumeration of all street lighting assets on public property including the characteristics required to classifiy the assets as Distribution Assets. This information was based on a detailed inventory count performed by a third party (the "Inventory Count"). The evidence also included a third party valuation of all street lighting assets purchased from the City using a depreciated replacement cost ("DRC") methdology (the "ValuQuest Study")[3].

13. In the period between the purchase of the Acquired Assets from the city in December 2006 and the submission of the Additional Evidence, THESI made additions to the street lighting assets (the "Additions") to meet the needs of the City. In addition, depreciation was recorded for both the Acquired Assets and the Additions (the

[1] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (February 11, 2010) Page 6 - 12
[2] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011)
[3] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 23 - 109

"Total Assets"). At the time of the submision of the Additional Evidence the net book value (the "NBV") of all street lighting assets in the books of THESI was $63.5 million[4].

14. The Inventory Count and the ValuQuest Study[3] were used by Toronto Hydro to determine what portion of the Total Assets' NBV of $63.5 million qualified as Distribution Assets. This resulted in $29.4 million of the Total Assets' NBV qualifying as Distribution Aseets which was included in the Additional Evidence. However, the OEB and the Intervenors challenged the amount of handwells and pole foundations to be included into the rate base, and Toronto Hydro agreed to reduce the transfer of Pole Foundations by 10%[5], hence the final approval from the OEB was $28.938 million of the Total Assets qualified as Distribution assets in the August Decision. This amount was then used as a basis of the transfer price on January 1, 2012 (the "Date of Transfer").

15. We understand that in 2012 THESL determined that the $28.938 million used as the transfer price for the Distribution Assets between THESI and THESL did not accurately reflect the actual NBV of the Distribution Assets and that further analysis was required.The Purchase and Sale Agreement between THESI and NewCo dated December 29, 2011 provided a provision to adjust the purchase price within 180 days of closing date. On October 10, 2012, the purchase price was adjusted to $42.473 million. As such, THESL submitted the Current Proposal detailing a revised methology to calcuate the transfer price of the Distribution Assets.

[4] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 20
[5] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (August 3, 2011) Page 11 - 15

Summary of Findings and Conclusions

16. Based on our knowledge, experience and analysis, and subject to the Scope of Review and Restrictions and Qualifications noted herein, our findings and conclusions in respect of the two questions posed in this report are outlined below:

Question 1:

17. Based on our understanding, depreciated historic cost ("DHC") should reflect the actual cost incurred in the acquisition and construction of the subject assets adjusted for depreciation. The Distribution Assets should be reported at DHC to ensure that THESL is appropriately compensated at the regulated rate of return for the investment made on its assets.

18. The following three-step approach was used to determine the value of the Distribution Assets as follows:

- Classification of the Total Assets into asset classes;
- Valuation of each individual asset class; and
- Allocation of the Total Assets into Distribution and Non-Distribution Assets.

19. The detailed classification of the Distribution assets was performed based on two asset groupings, further broken down into 6 asset classes. The assets were then categorized by age based on the Inventory Study.

20. The valuation methodology utilized in the Current Proposal relies on actual costs, where available, and depreciation details to estimate the DHC for the Additions. With respect to the Acquired Assets additional analysis was performed by allocating said assets into groups based on age, determining the standard replacement cost of the individual assets and deflating those costs based on the Consumer Price Index and depreciating the asset over its service life.

21. Based on our knowledge, experience and review of the detailed analysis, it is our view that Toronto Hydro utilized a reasonable method of estimating DHC in order to determine the value of the former street lighting assets and to identify the value of the assets eligible to be transferred from THESI to THESL and be included into the rate base.

Question 2:

22. We note from our review and analysis that there are differences in the approach used to value the Distribution Assets in the Original Application and the Current Proposal, however the underlying data is consistent as it relies upon the Inventory Study, the ValuQuest Study and the NBV in Toronto Hydro's books and records.

23. Based on our review, we noted that the Current Proposal incorporates a more detailed approach to estimating DHC.

24. Specifically the Current Proposal reflects actual costs borne by Toronto Hydro for the Additions and detailed analysis was undertaken to estimate the historic cost of the Acquired Assets as described above. Further, the Current Proposal considers the installation date of the Distribution Assets which was not contemplated in the Original Application.

25. Finally, the Original Application did not take construction work-in-progress (CWIP) into consideration, whereas the Current Proposal does.

26. Based on our knowledge, experience and review of Toronto Hydro's analysis, it is our view that revised methodology used to value the former street lighting assets provides a better proxy for the DHC of the assets than was provided to the OEB at the time of the August 2011 Decision.

Analysis and Findings

Question 1

"Is the revised detailed analysis prepared by Toronto Hydro of the value of former street lighting assets to be included in rate base determined using a reasonable method of calculating the depreciated historical cost of such assets?"

Depreciated Historic Cost

What is Depreciated Historic Cost?

27. In the context of the street lighting assets, DHC reflects the actual cost incurred in the acquisition and construction of the Total Assets less depreciation.

28. The ValuQuest Study submitted in the January 31, 2011 filing[3] utilized DRC to value the Total Assets. Per the ValuQuest Study, DRC considers the cost to reproduce or replace and install the assets being appraised. Per the Additional Evidence[6], DRC was used due to the fact that "*a conventional historic- cost valuation of the assets in question was not and could not be made available*" and "*DRC yields a result which most closely approaches the Board's requirement for 'an asset valuation to be prepared for the physical assets'* "

29. As stated in the Additional Evidence[7], "*A significant conceptual difference between these two approaches is that the DRC method adopts (as it must) the current replacement cost as the basis for the calculation, whereas historical cost accounting naturally reflects a lower nominal historical acquisition cost since that is built up over time as equipment is acquired, and partially reflects lower nominal acquisition costs prevailing several decades ago without the effect of intervening inflation*".

[6] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 16 - 17
[7] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 17

Why is DHC important?

30. As stated in the February Decision[8] and the August Decision[9], the amount to be included in rate base should be based on physical valuation of the assets and not a revenue-based fair market value approach. Further, in the Additional Evidence[10] THESL indicated that they seek to transfer an amount no greater than the actual net book value of the eligible distribution assets.

31. Regulated assets need to be reported at DHC to reflect the real cost borne by the organization in order to ensure that the organization is appropriately compensated at the regulated rate of return for the investment made on its assets.

Toronto Hydro's Revised Detailed Analysis

Overview

32. Toronto Hydro used the following three step approach to determine the value of the Distribution Assets:

    1) Classification of the Total Assets into asset classes;
    2) Valuation of each individual asset class; and
    3) Allocation of the Total Assets into Distribution and Non-Distribution Assets.

Classification of the Total Assets into asset classes

33. Using the Inventory Study, the Company organized the Total Assets into asset classes (and installation year, if applicable and where available) in order to consider the purpose, functionality or intended use of the assets.

34. To this end, Total Assets were organized into the two main asset classes qualifying as Distribution Assets per the February Decision[11] (i.e. Poles and Conductors). The assets within these two categories were then further disaggregated in order to allow Toronto Hydro to determine if a particular asset met the Distribution Asset criteria per the February Decision[11]. This process resulted in the identification of the following six asset classes:

[8] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (February 11, 2010) Pages 16, 19
[9] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (August 3, 2011) Page 12 - 13
[10] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 15
[11] EB-2009-0180, 0181, 0182, 0183, Decision and Order to Toronto Hydro-Electrical System Limited et al (February 11, 2010) Pages 7 - 12

1) "Poles", including:
    - Poles;
    - Handwells; and
    - Pole Foundations.

2) "Conductors", including:
    - Conduits;
    - Overhead Lines and Feeders; and
    - Underground Lines and Feeders.

35. There are two additional asset categories described in the February Decision, Streetlight Brackets and Conductors on Streetlight Brackets (including luminaires) and Expressway Lighting[11], which do not qualify as Distribution Assets and therefore were not considered by Toronto Hydro in the Current Proposal.

Valuation of each individual asset class

36. Asset valuation, in this context, refers to the process of estimating the DHC for each of the six asset classes noted above. We understand the asset valuation process was performed for both the Acquired Assets and the Additions.

Acquired assets

37. We understand based on discussions with Toronto Hydro management, and as stated in the August Decision, that the detailed historic cost information (by asset class and the year installed) of the Acquired Assets is not available. As such, an alternative approach was required to determine an estimate of the DHC of the Acquired Assets for the purpose of the Current Proposal.

38. We understand Toronto Hydro has utilized different approaches to estimate the DHC depending on the asset class and information available. A summary of the approaches by asset class follows below:

Poles, Handwells and Pole Foundations

39. In 2006, all poles, handwells, and pole foundations acquired as part of the transaction with the City were recorded as a single asset class named "poles, towers, fixtures" to which $24.5 million of the $60 million acquisition price was attributed.

40. The Inventory Study provided Toronto Hydro with physical information and installation year for each of the Acquired Assets in this class. The DHC of the Acquired Assets in this class was determined using the multi-step process described below.

Allocate Assets by Vintage Band

41. The first step was to allocate the Acquired Assets by age. Specifically, Toronto Hydro allocated the Acquired Assets into five year age bands ("Vintage Bands") ranging from 1971 to 2005, using the information in the Inventory Study. Each Vintage Band was designated and identified by the mid-point of the band (e.g. Assets installed between 1976 and 1980 would be designated as "1978 assets" for the purpose of this exercise).

Determine 2010 standard cost

42. The next step was to apply a standard cost per asset to the historic asset quantity in each Vintage Band. The standard cost was determined using the 2010 standard costs provided in the ValuQuest Study[3].

Calculate standard cost by installation year

43. In order to apply standard costs to historical quantities, Toronto Hydro deflated the current 2010 standard cost noted above, using 2010 Consumer Price Index rate, to the mid-points of each Vintage Band to arrive at sets of deflated standard costs for each Vintage Band.

Depreciate deflated standard cost

44. The final step in the process was to determine the accumulated depreciation for each Vintage Band based on the age and remaining useful life of each respective asset. The useful life of the assets was based on a 2009 useful life study conducted by Kinectrics Inc. entitled "Toronto Hydro Electric System Useful Life of Assets"[12] (the "Kinectrics Study"). The age of the assets (in years) was estimated using the mid-point of each Vintage Band.

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[12] Report: K-418021-RA-0001-R0002, Toronto Hydro Electric System Useful Life of Assets (August 28, 2009) Page 80

Conductors

45. Unlike Poles, which can be separately identified, underground/overhead lines and feeders as well as conduit (together the "conductors") are difficult to count and validate as they are not separately identifiable. As such, in order to determine the quantity and value for the conductors which qualify as Distribution Assets, Toronto Hydro started with the total NBV of all conductors as at the Date of Transfer and eliminated the two asset categories considered ineligible for inclusion as Distribution Assets, being (i) Expressway Lighting conductors and (ii) conductors which are used exclusively for street-lighting.

46. The value of the Expressway Lighting conductors was excluded using information in Table 4[13] of Appendix B of the Additional Evidence "*Derivation of NBV by Asset Group and Classification*".

47. Additionally, Toronto Hydro used the proportion of assets deemed as distribution from the Table 4[13] of Appendix B of the Additional Evidence "Derivation of NBV by Asset Group and Classification". The proportion which qualifies as Distribution Assets was based on the detailed count from the Inventory Study.

Additions

48. Since the acquisition of the initial portfolio of street lighting assets from the City in 2006, Toronto Hydro has constructed and acquired additional street lighting assets.

49. We understand that as new street lighting assets were constructed and installed by THESI in the period between 2006 and 2011, the Company maintained detailed records of actual costs by installation year. We further understand that the Additions were depreciated based on the Kinectrics Study[12] as follows:

- Cabling is depreciated over a life span of 40 years; and
- Poles, Civil (Handwells, Tap Box), Conductors are depreciated over a life span of 50 years.

50. Based on the information above the Company has been able to calculate the DHC of the Additions based on the actual cost and depreciation details in its books and records.

[13] EB-2009-0180, 0181, 0182, 0183, Additional Evidence Regarding The Transfer of Streetlighting Assets (January 31, 2011) Page 19

Allocation of the Total Assets into Distribution Assets and non-Distribution Assets

51. The allocation process refers to the bifurcation of the DHC for each of the six asset classes between Distribution Assets and non-Distribution Assets.

Poles, Handwells and Pole Foundations

52. Allocation rates for poles, handwells, and pole foundations were determined based on the ratio of estimated number of assets eligible for transfer to THESL and total poles, handwells and pole foundations. Eligibility of poles was determined based on the Inventory Study and the criteria set by the OEB in the February Decision.

53. These allocation rates were then multiplied by the DHC of each asset in each Vintage Band to determine the DHC value to transfer to THESL.

The following is an illustrative example of the allocation process:

Vintage Band	DHC ($ millions) A	Total Number of Assets B	Distribution Assets C	Percentage to be Transferred D = C/B	Value to be Transferred ($ millions) E = A x D
Band 1	8	2,000	1,800	90%	7.2
Band 2	12	2,400	2,200	92%	11.0
Band 3	13	4,000	3,500	75%	9.8
Total	**33**	**8,400**	**7,500**	**89.3%**	**28.0**

(The numbers in the table are for illustrative purposes only and do not reflect the actual amounts filed by THESL)

Conductors

54. For conductors, an allocation rate was estimated based on the Inventory Study. Specifically, Toronto Hydro, using the Inventory Count details determined that a certain percentage of conductors were Expressway Lighting and therefore excluded from the Distribution Asset pool. Of the remaining conductor assets, a further deduction was made to remove the percentage of conductors used exclusively for street lighting. The remaining percentage was determined to represent conductors which qualify as Distribution Assets.

55. The conductor allocation percentage was then applied to the total conductor DHC to arrive at the conductor DHC eligible for distribution which was included in the Current Proposal.

56. We understand the conductor allocation percentages remain unchanged from the Additional Evidence which was accepted by the OEB in the August decision.

Construction work-in-progress

57. In addition to the acquired and constructed assets discussed above, Toronto Hydro also included CWIP balances that qualify as Distribution Assets in the Current Proposal. To the extent possible, Toronto Hydro used the construction and capitalization records, which include actual costs, to identify which CWIP assets qualify as Distribution Assets based on the criteria set out in the February Decision. For the remaining CWIP, Toronto Hydro has applied an assumed percentage of Total Assets which qualify as Distribution Assets based on the processes described above.

Conclusion

58. Based on our knowledge, experience and review of the detailed analysis noted above, and subject to the Scope of Review and Restrictions and Qualifications noted herein, it is our view that Toronto Hydro utilized a reasonable method of calculating DHC in order to determine the value of the former street lighting assets to identify the value of the assets eligible to transfer from THESI to THESL and therefore be included into the rate base.

Question 2

"Does the revised method used to value the former street lighting assets provide a better proxy for the depreciated historic cost of the assets than was provided to the OEB at the time of the August 2011 decision?"

59. The methodology used to determine the transfer price of the street lighting assets in the Current Proposal has been summarized in Question 1. The response to this question will focus on the methodology used in the Original Application and the key differences between the two methodologies.

Methodology used in the Original Application

60. We understand the estimate of the transfer price of the Distribution Assets which was included in the Original Application was based on the following three pieces of information:

1) The ValuQuest Study[3];
2) The Inventory Study; and
3) The total net book value of all street lighting assets[13].

61. There were no changes in the ValuQuest Study and the Inventory Study between the two applications. The NBV was adjusted to the date of the Current Proposal based on additions and depreciation during the period between the applications.

62. The classification of the assets into asset classes in the Original Application was based primarily on the ValuQuest Study. Specifically, Toronto Hydro used the DRC of each asset class per the ValuQuest study[3] and divided it by the total DRC of all street lighting assets to determine the DRC percentage by asset class[13]. The DRC percentage by asset class was then applied to the NBV of the Total Assets to arrive at the estimated transfer value by asset class.

63. The estimated DHC by asset class was then allocated between Distribution Assets and non-Distribution Assets. We understand the allocation methodology for conductors was consistent between the Original Application and the Current Proposal. With respect to the Poles, the Original Application determined the Distribution

allocation percentage using the total number of poles which met the distribution criteria in the February Decision[11] using the Inventory Study, divided by the total number of poles. We further understand that the installation date of said poles was not considered in arriving at the allocation percentage.

Key differences between the Original Application and the Current Proposal

64. Both applications were derived from the same sources of information being the ValuQuest Study, the Inventory Count and the NBV of the street lighting assets in THESI's books and records.

65. A significant conceptual difference between the Original Application and the Current Proposal is the reliance on DRC versus DHC as the basis for the valuation of the Distribution Assets. Both methods consider and incorporate the concept of depreciation. However, as previously stated, the starting point for DHC is the cost of the asset at the time of acquisition whereas the starting point for the DRC is the current cost of replacement.

66. The table below summarises the differences in approach used in the Original Application as compared to the Current Proposal.

	Original Application	Current Proposal
Classification	• Considers the asset classes as required in order to determine the purpose, functionality or intended use of the assets and meet the OEB criteria.	• Considers the asset classes as required in order to determine the purpose, functionality or intended use of the assets and meet the OEB criteria; and • Considers classification into Vintage Band or, where available, installation year.
Valuation	• Uses DRC per the ValuQuest Study as the basis for the valuation; and • DRC is decreased to NBV based on a	• Uses actual NBV by asset class and installation date where available (the Additions);

	Original Application	Current Proposal
	percentage of the DRC by asset class applied to the NBV of the Total Assets.	• Estimates the historic cost for Acquired poles using the standard cost per the ValuQuest Study adjusted for inflation; • Calculates the depreciation for the Acquired poles based on the Kinectrics Study and Vintage Band; • Uses the purchase price for the Acquired conductors at the Date of Transfer adjusted for depreciation; and • Includes a value for CWIP based on the actual books and records.
Allocation	• Uses the Inventory Count to identify the percentage of poles which meet Distribution criteria; and • Uses the information in the ValuQuest Study to exclude the Expressway Lighting conductors and conductors used only for street lighting.	• Uses the Inventory Count by Vintage Band or installation year to identify the poles which meet the Distribution criteria where available; • Uses the information in the ValuQuest study to exclude the Expressway Lighting conductors and conductors used only for Street Lighting; and • Allocates CWIP to Distribution Assets based on completed construction and cost information, where available, uses an allocation percentage for the remainder.

67. Using the date of installation either by year or Vintage Band allows Toronto Hydro to perform the second two steps in their process at a more detailed level.

68. There is different information available for the Additions and the Acquired Assets therefore separating these two groups allows THESL to refine the calculations to utilize the best information available for each category of asset.

69. The Original Application estimated a deflated value of the Total Assets through the process of allocation the DRC to the NBV at the Date of Transfer on a total basis. The cost of the Acquired assets used in the Current Proposal is a better proxy of the historic cost due to the fact that the replacement cost is deflated to the mid-point of the Vintage band. Further this process is performed only for the Acquired Assets as the actual cost of the Additions is known.

70. Cost and depreciation details are readily available for the Additions. The Current Proposal incorporates actual historical costs and depreciation which is the most reflective method of calculating DHC. The Original Application applied an estimate using the process described above.

71. The inclusion of the CWIP in the Current Proposal also provides a holistic view of all distribution assets that may be deemed transferrable to THESL.

72. In the Current Proposal, Toronto Hydro performed the Allocation to Distribution Assets of the pole assets (i.e. poles, handwells, foundations) by Vintage Band and installation year rather than the high level allocation rate used in the Original Application. As such the allocation in the Current Proposal provides a better proxy of assets eligible for transfer to THESL.

Conclusion

73. Based on our knowledge, experience and review of the detailed analysis noted above, and subject to the Scope of Review and Restrictions and Qualifications noted herein, it is our view that revised methodology used to value the former street lighting assets provides a better proxy for the DHC of the assets than was provided to the OEB at the time of the August Decision.

Respectfully submitted,

(Signed) “PricewaterhouseCoopers LLP”

Ken Goodwin
Partner

Appendix A

Ken Goodwin, MBA, CA•CBV
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Ken Goodwin is a Partner in PricewaterhouseCoopers LLP's Valuation Forensics & Disputes practice and the lead for PwC Canada's Power & Utilities Deal team. He has specialized in valuations on a full-time basis since 1998 and has performed valuations in a variety of contexts including analysing and commenting on client prepared valuation models, providing fairness opinions to Boards of Directors, assisting in pricing analyses related to potential transactions, preparing and reviewing purchase price allocations and other fair value related exercises, income tax reorganizations and strategic planning.

Ken has prepared and reviewed dozens of valuations of power generation, electric distribution and transmission companies in a variety of contexts including merger and acquisition activity, financial reporting, tax reorganizations and strategic planning. These assignments focused on obtaining an understanding the support for key financial inputs, testing the mathematical accuracy and integrity of the models, and preparing comments and research in support of discount rates used for the transactions.

Ken is a Chartered Business Valuator (CBV), Chartered Accountant (CA) and has a Masters of Business Administration (MBA) from the University of Toronto.

Appendix B

Restrictions and Qualifications

We understand that this Report and related appendices are intended to be tendered into evidence by THESL in EB-2014-0116 and solely for the purposes described in the Assignment section. The release of this Report, in whole or in part, to any party outside of this proceeding will require our prior written consent. We do not assume any responsibility or liability for losses incurred by any party as a result of the circulation, publication, reproduction or use of this Report contrary to the provisions of this paragraph.

We caution that the calculations, estimates and statements made in this Report are based solely on the information reviewed and communicated to us to date. We reserve the right to review all calculations, estimates and statements made or referred to in this Report and, if we consider it necessary, to revise our Report in light of any relevant information that becomes known to us after the date of this Report.

Our Report and related analysis must be considered as a whole. Selecting only portions of the analysis or the factors considered by us, without considering all factors and analysis together, could create a misleading view of our findings. The preparation of our analysis is a complex process and is not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor or analysis.

Our review does not constitute an audit as defined by Canadian generally accepted auditing standards. The primary sources of information reviewed and relied upon are referred to in the Scope of Review section of this report. We have indicated the sources of factual information relied upon. Unless otherwise noted, we have not sought external verification of the information provided by Toronto Hydro or other sources as listed.

Our analysis is financial in nature. We make no representation regarding questions of legal interpretation.

The individuals that prepared this report did so to the best of their knowledge, acting independently and objectively in accordance with Rule 13A of the OEB's Rules of Practice and Procedure.

PwC's compensation is not contingent on an action or event resulting from the use of this Report.

Toronto Hydro-Electric System Limited
EB-2014-0116
Exhibit 2A
Tab 5
Schedule 2, Appendix A
Filed: 2014 Sep 23
(4 pages)

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Toronto Hydro Street Lighting Assets

September 23, 2014

Assessment of the valuation methodology used by Toronto Hydro in EB-2014-0116 - Addendum

pwc

Introduction

A-1 PricewaterhouseCoopers LLP (“we”, “us” or “PwC”) was previously engaged by Tory’s LLP on behalf of Toronto Hydro-Electric Systems Limited (Toronto Hydro) to author a report entitled “Toronto Hydro Street Lighting Assets; Assessment of the valuation methodology used by Toronto Hydro in EB-2014-0116” (the “Report”) dated July 28, 2014. The Report provided an opinion on whether Toronto Hydro’s analysis in support of its rate application EB-2014-0116 was a reasonable method of calculating depreciated historic cost (“DHC”) of street lighting assets and whether the method provided a better proxy of the depreciated historic cost of the street lighting assets than that used by Toronto Hydro in support of the OEB decision related to filings EB-2009-0180, EB-2009-0181, EB-2009-0182 and EB-2009-0183 dated August 3, 2011 (the “August 2011 Decision”).

A-2 Subsequent to issuing the Report, management of Toronto Hydro (“Management”) informed us that better aging information for poles, handwells and pole foundations had come to their attention. Management has represented that this new aging information is better data than that used in support of the EB-2014-0116 application which was the basis of the Report.

A-3 The purpose of this addendum is to discuss the impact of this new information on the methodology employed and the resulting DHC estimate of the street lighting assets.

Original Aging Information

A-4 Management has represented to us that the original aging information related to poles, handwells and foundations used in the EB-2014-0116 application was from Toronto Hydro’s Geo-Spatially Enabled Asset Registry (“GEARS”) database.

A-5 This database contains a cataloge of the street lighting and expressway lighting assets by the asset’s location, condition and other parameters necessary to properly classify the assets according to the terms of OEB decision related dto filings EB-2009-0180, EB-2009-0181, EB-2009-0182 and EB-2009-0183 dated February 11, 2010.

A-6 We understand that within the GEARS database a significant percentage of the poles had no installation date and were assumed by Management to have been installed prior to 1971, resulting in the majority of the poles having an assigned age greater than 40 years. Similarly the aging information for the handwells and foundations suggested that the majority of these asset categories were installed prior to 1971.

Revised Aging Information

A-7 The revised aging information is based on Toronto Hydro's Optimal Investment Portfolio ("OIP") study, which was conducted in 2004 to assess the vintages of all major assets in Toronto Hydro's system. We understand this information was also used to implement IFRS-consistent changes related to the manner in which Toronto Hydro accounts for it's assets. Specifically, the study assisted Toronto Hydro in attributing an installation date to poles, handwells and foundations for which no aging information was previously available.

A-8 The OIP data exists for poles, handwells and foundations for the relelvant vintage bands leading up to the original Toronto Hydro purchase of the street lighting assets from the City of Toronto (the "City") in 2006. The aging analysis is only necessary for pre-2006 assets as detalied records have been maintained for all assets installed subsequent to the initial purchase from the City.

Imapact of Revised Aging Information on Methodology

A-9 Toronto Hydro has informed us that no changes have been made to the methodology used to calculate DHC as described in EB-2014-0116 and that Management has recalculated the DHC estimates of the street lighting assets using the new aging information.

A-10 We have obtained the revised analysis and discussed the application of the methodology with Management and note that the methodology appears to have been applied in a manner consistent with that outlined in the Report.

Conclusion

A-11 As a result of the foregoing, and subject to the Restrictions and Qualifications noted in the Report, without commenting on the inputs and data used, we maintain our view that Toronto Hydro utilized a reasonable method of calculating DHC in order to determine the value of the former street lighting assets and that the methodology is a better proxy than that provided to the OEB at the time of the August 2011 Decision.

Respectfully submitted,

(signed) "PricewaterhouseCoopers LLP"

Ken Goodwin
Partner

CAPITAL EXPENDITURES

In accordance with the OEB's Chapter 5 Filing Requirements, Toronto Hydro has filed a consolidated Distribution System Plan ("DSP") at Exhibit 2B. In this schedule, Toronto Hydro files OEB Appendix 2-AA (Capital Projects Table) and OEB Appendix 2-AB (Capital Expenditures Summary), as required by s. 2.5.5.2 of the OEB's Filing Requirements. In accordance with the Filing Requirements, this schedule also provides:

- a description of the proposed accounting treatment for projects that have a lifecycle greater than one year, including the treatment of the cost of funds; and
- the components of other capital expenditures, including a reconciliation of all capital components to the Total Capital Budget.

1. OEB-Required Appendices (2-AA and 2-AB)

Appendices 2-AA and 2-AB, which are filed at Exhibit 2A, Tab 6, Schedules 2 and 3, provide an overview of Toronto Hydro's capital expenditures from 2010 to 2019, by program and by investment category, respectively.

To maximize the usefulness of these appendices, Toronto Hydro mapped its historical and future capital expenditures to the investment categories, and programs presented in the DSP. Capital expenditures associated with historical programs that could not be mapped to an existing DSP program are only presented in the 2010 to 2014 timeframe, as applicable. Written variance explanations of Toronto Hydro's capital expenditures are provided at Exhibit 2B, Section E4.

Toronto Hydro's last rebasing application (EB-2010-0142) was settled, and the Settlement Agreement, which was approved by the OEB, reflected a reduction in capital expenditures of $119.2 million for the 2011 test year.[1] As a result, Toronto Hydro is

[1] EB-2010-0142, Partial Decision and Order (July 7, 2011) at pages 2 and 3 and at section 4.2 of the Settlement Agreement (Appendix C to the Partial Decision and Order).

unable to provide a granular variance analysis of actuals versus OEB-approved amounts. On a total basis, Toronto Hydro's 2011 OEB approved capital expenditures were $378.8 million, and its actual capital expenditures were $445.5 million.

2. PROPOSED ACCOUNTING TREATMENT RE PROJECTS WITH A LIFE CYCLE GREATER THAN ONE YEAR

Some of Toronto Hydro's capital projects have a project life cycle greater than one year. Where large projects span multiple years, the construction costs are recorded in construction work in-progress ("CWIP") accounts until they are in-service. Under Canadian Generally Accepted Accounting Principles ("CGAAP") and United States Generally Accepted Accounting Principles ("USGAAP"), projects with a construction duration of greater than six months include a financing charge in the cost of assets capitalized. The financing charge is at the interest rate published quarterly by the OEB for CWIP. Under Modified International Financial Reporting Standards ("MIFRS"), projects expected to exceed a duration of greater than six months include a financing charge in the cost of assets capitalized. The interest rate used to calculate the financing charge for MIFRS is Toronto Hydro Corporation's weighted average cost of borrowing.

3. COMPONENTS OF CAPITAL EXPENDITURES

Toronto Hydro's capital expenditures under the Other Capital Expenditures investment category include engineering capital, road cuts, allowance for funds used during construction, inflation and miscellaneous, all of which are summarized below.

3.1. Engineering Capital

Engineering capital represents labour costs that are capitalized although they are not directly attributable to specific distribution system assets or projects. These costs consist of the labour costs of engineers, technologists, design technicians and power system controllers ("PSCs") for engineering, design and planning work that they perform on distribution assets that are put in-service. Such planning and design work is non-discretionary and is critical to Toronto Hydro's ability to complete capital work as it continues its focus on the following key areas: the capital investment program to address aging equipment and legacy infrastructure, development and implementation of new approaches for engineering decision support for creation and optimization of capital programs, and modernization through new technologies and systems. Engineering capital expenditures are only included in Other Capital Expenditures from 2010 to 2011. From 2012 onwards, these costs were integrated within capital investment programs, and this is captured in the reduction of costs within this category from 2011 onwards to 2012.

3.2. Historical Road Cut Repairs

When Toronto Hydro installs equipment in the ground it generally must disturb the environment around the job site (such as sidewalks and roadways). Temporary repairs to the property are done when the utility completes construction. This is required to make the area safe for the public and provide continuity of the surface with the surrounding area. Permanent repairs are made later by contractors engaged by the City of Toronto, usually anywhere from one to four years after Toronto Hydro has completed construction. At that time, Toronto Hydro is invoiced at for the cost of the restoration work. The timing of these repairs is generally out of the utility's control. Most jobs tend to get tendered by the City anywhere from 18 to 30 months after job completion. As a result of the outstanding costs for road cut repairs related to historical jobs, Toronto Hydro continues to receive and be legally obligated to pay invoices for repairs for road cuts dating back as far as 30 months. Any variance between the historical estimated repair cost and actual City invoice represent an obligation to the City of Toronto, pursuant to its authority over highways (public roads) under sections 32 and 33 of the *City of Toronto Act, 2006*.[2]

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[2] S.O. 2006, C. 11, Sched. A, at sections 32-33. ["*City of Toronto Act*"]

3.3. Allowance for Funds Used During Construction (AFUDC)

The Accounting Procedures Handbook, Article 410, allows the utility to capitalize an allowance for funds used during construction ("AFUDC"). The AFUDC rate applied by Toronto Hydro for 2010 to 2013 actuals and 2014 forecast is based on the OEB-prescribed rate. The forecasted 2015 capital expenditures are based on MIFRS and thus include AFUDC calculated based on Toronto Hydro's weighted average cost of debt.

3.4. Inflation

From 2016 onwards to 2019, inflation costs at 2.07% per year, consistent with the Statistic Canada Consumer Price Index ("CPI") for Toronto[3], are also included within this category.

3.5. Miscellaneous

Miscellaneous capital expenditures primarily include pre-capitalized inventory and major tools. Capital expenditures related to pre-capitalized inventory is dependent on the change in capital inventory levels year over year. Toronto Hydro invests in major tools and testing equipment to allow employees to continue to complete work effectively and efficiently. The utility invests in major tools on an ongoing basis to replace worn or broken tools, and as required to install, commission and maintain new technologies. These are regular utility expenses that are essential to being able to perform necessary capital and maintenance work.

[3] Statistics Canada, *Consumer Price Index, by city (Index)*, (Ottawa: Statistics Canada, 2014), online: Statistics Canada <http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ45a-eng.htm>.

OEB Appendix 2-AA
Capital Projects Table

Projects	2010	2011	2012	2013	2014 BRIDGE	2015 TEST	2016 TEST	2017 TEST	2018 TEST	2019 TEST
Reporting Basis	**CGAAP**	**CGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Metering	28.4	22.1	12.1	12.2	14.0	24.7	16.6	14.7	11.7	13.7
Customer Connections	15.2	31.2	31.0	53.4	52.1	39.3	53.8	64.9	56.9	46.6
Externally-Initiated Plant Relocation & Expansion	0.7	5.0	9.8	18.6	8.8	4.0	4.0	4.0	4.0	4.0
Load Demand	-	-	0.3	2.4	1.1	12.0	13.9	14.0	15.7	19.2
Generation Projects Protection and Control	-	-	-	-	-	6.1	5.2	3.3	2.1	2.0
System Access Investments Sub-total	**44.4**	**58.3**	**53.2**	**86.6**	**76.0**	**86.1**	**93.5**	**100.9**	**90.4**	**85.5**
Underground Circuit Renewal	108.4	90.3	53.8	68.8	108.1	96.0	80.1	84.0	99.7	99.5
Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers	-	5.5	1.5	2.4	4.7	3.5	1.4	0.7	0.8	0.5
Underground Legacy Infrastructure	-	-	-	-	-	2.1	6.7	6.6	6.5	5.5
Overhead Circuit Renewal	25.8	28.3	23.2	49.0	53.3	44.0	23.0	24.9	25.3	30.3
Overhead Infrastructure Relocation	-	-	-	-	-	0.7	1.4	1.8	2.3	3.6
Rear Lot Conversion	6.9	16.6	17.5	23.8	22.7	17.0	8.1	10.3	10.3	13.6
Box Construction Conversion	5.7	7.1	0.8	13.8	23.3	16.8	20.7	21.1	21.6	22.7
SCADAMATE R1 Renewal	-	-	-	1.9	2.6	6.2	4.1	2.7	-	-
Network Vault Renewal	1.7	0.9	3.6	10.8	0.9	4.0	10.4	10.3	10.3	10.2
Network Unit Renewal	7.3	4.4	5.1	7.3	3.6	5.2	7.4	7.3	7.3	7.3
Legacy Network Equipment Renewal (ATS & RPB)	0.4	0.0	0.1	1.6	0.2	0.4	1.0	1.1	0.9	1.1
Network Circuit Reconfiguration	-	-	-	-	-	-	2.3	2.3	2.3	2.3
Stations Switchgear Renewal	14.9	12.9	11.6	7.9	24.6	11.9	18.9	25.5	27.6	22.4
Stations Power Transformer Renewal	1.8	4.0	2.7	1.7	1.3	1.7	2.6	2.6	2.7	2.7
Stations Circuit Breaker Renewal	0.0	0.9	0.2	1.0	2.1	1.7	1.8	1.8	2.1	1.8
Stations Control & Monitoring	-	-	0.1	0.5	0.2	0.1	0.9	1.1	1.5	1.4
Stations Ancillary Systems	0.1	0.1	0.2	0.6	0.2	0.7	0.6	0.4	0.3	0.4
Station Buildings	-	-	0.5	0.0	0.2	0.5	2.5	2.3	2.6	3.3
Stations DC Battery Renewal	0.2	0.2	0.4	0.3	0.6	0.3	0.7	0.7	0.7	0.7
Reactive Capital	25.1	28.6	29.2	37.4	32.1	31.9	32.7	33.1	33.6	34.2
Worst Performing Feeder	16.7	19.3	6.7	1.2	4.8	1.2	1.8	1.8	1.8	1.8
Telecom Program	-	-	-	1.0	0.9	6.1	6.0	4.0	-	-
System Renewal Investments Sub-total	**215.0**	**219.3**	**157.2**	**231.1**	**286.4**	**251.7**	**235.0**	**246.3**	**260.1**	**265.5**
Contingency Enhancement	-	-	-	-	-	10.0	5.9	9.7	9.7	13.5
Design Enhancements	-	-	-	-	-	0.4	1.7	1.7	1.7	1.7
Feeder Automation	3.3	0.9	6.2	8.8	0.8	11.1	15.1	9.4	10.0	8.5
Overhead Momentary Reduction	-	-	-	-	-	-	-	0.6	0.6	0.6
Handwell Upgrades	21.1	32.9	12.6	11.7	16.2	5.0	-	-	-	-
Polymer SMD-20 Renewal	-	-	-	0.8	2.8	4.8	-	-	-	-
Downtown Contingency	1.1	4.7	0.1	1.1	1.0	-	0.7	0.7	1.0	0.9
Customer Owned Station Protection	-	-	-	-	-	0.6	1.0	1.0	0.8	0.6
Stations Expansion	6.9	32.5	18.6	61.2	79.5	43.8	41.6	36.5	22.0	44.0
Energy Storage Systems	-	-	-	-	1.0	0.5	1.1	2.2	3.2	3.8
Local Demand Response	-	-	-	-	-	0.2	2.4	0.6	0.5	0.3
Grid Intelligence	3.0	4.8	0.8	0.1	-	-	-	-	-	-
EV	-	-	0.0	0.0	-	-	-	-	-	-
System Service Investments Sub-Total	**35.3**	**75.6**	**38.4**	**83.7**	**101.3**	**76.5**	**69.6**	**62.5**	**49.5**	**73.9**
Fleet and Equipment Services	10.6	11.8	0.8	2.2	2.6	3.9	3.2	3.7	3.5	3.6
Facilities	12.1	25.3	6.6	14.5	90.3	53.8	24.2	2.0	2.0	1.9
IT Hardware	10.6	9.4	7.4	6.0	5.2	5.9	8.0	7.4	9.8	5.6
IT Software	22.2	21.2	14.5	9.6	10.1	15.5	16.2	15.8	16.8	16.8
Radio Project	-	-	-	-	-	6.7	13.7	-	-	-
ERP*	-	-	-	1.5	0.9	17.7	33.6	-	-	-
Program Support	-	-	-	-	0.4	1.2	0.5	-	-	-
General Plant Investments Sub-Total	**55.5**	**67.7**	**29.3**	**33.8**	**109.5**	**104.6**	**99.4**	**28.9**	**32.1**	**27.9**
Miscellaneous	12.3	(4.2)	4.5	5.4	3.2	0.9	1.2	1.2	1.2	1.2
AFUDC	3.5	5.2	2.3	3.3	6.5	8.0	5.8	4.5	4.6	4.6
Roadcuts	-	-	3.1	1.8	3.0	3.3	4.1	4.1	4.1	4.1
EAR	34.5	23.6	-	-	-	-	-	-	-	-
Inflation	-	-	-	-	-	-	10.2	18.9	28.0	39.5
Other Sub-Total	**50.4**	**24.6**	**9.9**	**10.5**	**12.7**	**12.2**	**21.2**	**28.6**	**37.9**	**49.4**
Total	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**531.1**	**518.8**	**467.4**	**470.0**	**502.2**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-	-	(6.3)	(5.9)	(5.1)	(5.0)	(5.4)
Total	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**524.9**	**512.9**	**462.3**	**465.0**	**496.7**

OEB Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

CATEGORY					**Forecast Period** (planned)					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	Actual	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**	**Test**	**Test**	**Test**	**Test**
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*
System Access	44.4	58.3	53.2	86.6	76.0	86.1	93.5	100.9	90.4	85.5
System Renewal	215.0	219.3	157.2	231.1	286.4	251.7	235.0	246.3	260.1	265.5
System Service	35.3	75.6	38.4	83.7	101.3	76.5	69.6	62.5	49.5	73.9
General Plant	55.5	67.7	29.3	33.8	109.5	104.6	99.4	28.9	32.1	27.9
Others	50.4	24.6	9.9	10.5	12.7	12.2	21.2	28.6	37.9	49.4
TOTAL EXPENDITURE	**400.6**	**445.5**	**288.0**	**445.7**	**585.9**	**531.1**	**518.8**	**467.4**	**470.0**	**502.2**
System O&M	$ 114.6	$ 111.9	$ 109.0	$ 119.8	$ 118.9	$ 128.8				

Note: Variances due to rounding may exist

CAPITALIZATION POLICY

This schedule addresses section 2.5.2.3 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements") which requires applicants to file a copy of their capitalization policies and to identify changes to their capitalization policy.

1. BACKGROUND

In 2007, Toronto Hydro commenced its International Financial Reporting Standards ("IFRS") conversion project with the intention of converting to IFRS on January 1, 2011. However, given uncertainty around the timing, scope and potential adoption of a rate-regulated accounting standard under IFRS, Toronto Hydro decided to defer the adoption of IFRS, and filed its 2011 rate application in accordance with its Canadian Generally Accepted Accounting Principles ("CGAAP") accounting practices in use at that time.

Prior to January 1, 2011, Toronto Hydro recorded depreciation and amortization on assets in accordance with the guidelines provided in the OEB's 2006 Electricity Distribution Rate Handbook ("EDRH"). The use of the guidelines was permitted under the CGAAP as the prescribed useful lives represented the "estimated service lives" of assets under the regulatory framework.

Effective January 1, 2011, following a detailed review of the useful lives analyses conducted by Kinectrics and other third-parties for Toronto Hydro for the purposes of the IFRS conversion, the utility implemented certain changes in accounting estimates related to the manner in which it records and accounts for its property, plant and equipment ("PP&E").[1] Although Toronto Hydro decided to defer the adoption of IFRS, it determined that these changes were required to be applied under CGAAP as additional and more relevant information had been made available.

[1] EB-2010-0142, Application and Evidence (February 9, 2011) at Exhibit Q1, Tab 2, Schedule 7-2; and EB-2010-0142, Partial Decision & Order, (July 7, 2011) at page 41.

These changes in the estimates of useful lives of assets were reflected in the corresponding depreciation and amortization balances in Toronto Hydro's financial statements effective January 1, 2011, and the utility's last rebasing application (EB-2010-0142).[2] Toronto Hydro's external auditor acknowledged the appropriateness of the changes in accounting estimates effective January 1, 2011 under CGAAP,[3] and the Ontario Energy Board ("OEB") approved, for rate-making purposes, the depreciation and amortization expense that resulted from these changes effective May 1, 2011.

On July 21, 2011, the Ontario Securities Commission ("OSC") granted Toronto Hydro an exemption to prepare its financial statements in accordance with USGAAP for its fiscal years beginning on or after January 1, 2012, but before January 1, 2015. Toronto Hydro adopted USGAAP for financial reporting and ratemaking purposes effective January 1, 2012.

On March 19, 2014, the Board of Directors approved the adoption of IFRS for the year beginning on January 1, 2015 due to the pending expiration of the above exemption.

On June 23, 2014, Toronto Hydro presented the IFRS policies to its Audit Committee. Once the IFRS policies are approved by the Audit Committee, Toronto Hydro intends to adopt a revised Capitalization Policy.

2. CAPITALIZATION POLICY

A copy of Toronto Hydro's current capitalization policy is filed as Appendix A to this schedule. As explained above, Toronto Hydro's Audit Committee is in the process of reviewing the revised IFRS policies. Therefore, the current capitalization policy filed at Appendix A to this schedule is based on USGAAP.

[2] EB-2010-0142 Exhibit Q1, Tab 1, Schedule 1,
[3] Toronto Hydro Corporation Consolidated Financial Statements December 31, 2011

Toronto Hydro confirms that for purposes of calculating rate base for the 2015 Test Year (Exhibit 2A, Tab 1, Schedule 1), its capitalization practices conform with IFRS guidance. Toronto Hydro does not expect the new IFRS Capitalization Policy to have any material impact on its 2015 test year rate base values.

3. CHANGES TO CAPITALIZATION POLICY

With the exception of the items noted below, there are no material differences between USGAAP and IFRS capitalization practices. The incremental net impact of the items listed below to the 2015 test year rate base is $0.1 million. The following table summarizes the differences between USGAAP and IFRS.

Topic	Aspect	USGAAP	IFRS
Borrowing Costs	Applicability	Assets requiring a “period of time” to complete	Assets requiring a “substantial period of time” to complete
	Commencement Date	After inception, not retroactive	At inception, on all project spend
	Interest Rate	OEB prescribed rate	Weighted average cost of borrowing
	Calculation	Simple Interest	Compounding Interest
Assets Retirement Obligation	Discount Rate	Credit adjusted risk free rate	Risk free rate
	Presentation	Accretion Expense shown as Operating Expense	Accretion Expense shown as Interest Expense
	Timing	Legal obligation	Legal or Constructive Obligation

POLICY

CAPITALIZATION	**Policy Owner:** Chief Financial Officer
	Policy Approver: Policy Administration Steering Committee
	Version Approval Date: 2013-09-24
	Last Review by PASC: 2013-09-24
The most recent version of this policy can be obtained from http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx	
The distribution of this policy is not restricted.	

TABLE OF CONTENTS

1 DOCUMENT REVIEW & REVISION HISTORY

This policy is reviewed annually.

Version Number	Date of Review	Reviewed By	Brief Description of Change
V1.0	2008-06-27	PASC	V1.0 approved by PASC
V2.0	2010-07-29	PASC	V2.0 approved by PASC
V3.0	2011-06-30	PASC	V3.0 approved by PASC
V4.0	2013-09-24	PASC	V4.0 approved by PASC

2 DISTRIBUTION HISTORY

Version Number	Date of Issue	Recipients
V1.0	2008-06-27	Toronto Hydro @ Home Employee Extranet
V2.0	2010-08-30	Toronto Hydro @ Home Employee Extranet
V3.0	2011-09-16	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx
V4.0	2013-09-30	http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx

3 POLICY OVERVIEW

This document describes the accounting policy and specific criteria used to determine the appropriate classification of expenditures, in particular, whether expenditures should be capitalized on the balance sheet (capital assets) or expensed to operations in the period incurred (expense).

The purpose of recording expenditures as capital assets is to provide for an equitable allocation of costs among current and future periods. As capital assets are expected to provide future economic benefits for more than a year, expenditures incurred for the acquisition, construction or development of capital assets should be capitalized and allocated over the estimated useful lives[1] of the associated capital assets in the form of amortization/depreciation. All other expenditures should be expensed in the accounting period incurred.

4 DEFINITIONS AND ABBREVIATIONS

TERM or ACRONYM	DESCRIPTION
AFUDC	Allowance for Funds Used During Construction
AP Handbook	Accounting Procedures Handbook for Electricity Distributors issued by the OEB
ASC	Accounting Standards Codification
CWIP	Construction Work In Progress
Corporation	Toronto Hydro Corporation and its affiliates
FASB	Financial Accounting Standard Board
OEB	Ontario Energy Board
On-cost	Materials handling costs
PASC	Policy Administration Steering Committee The committee members are: Chief Financial Officer VP, General Counsel & Corporate Secretary VP, Organizational Effectiveness and Environment Health & Safety VP, Information Technology and Strategic Management
PP&E	Property, Plant and Equipment
SLR	Standard Labour Rate
US GAAP	United States Generally Accepted Accounting Principles
VHR	Vehicle Hire Rate

5 SCOPE

5.1 This policy applies to Toronto Hydro Corporation and its affiliates.

6 OBJECTIVE

6.1 To ensure proper classification of the Corporation's expenditures in accordance with US GAAP, and compliance with applicable regulations.

7 CRITERIA FOR CAPITALIZATION

7.1 Asset Recognition – Capitalization versus Expensing

[1] Estimates of useful life are reviewed periodically and whenever events or changes in circumstances indicate that the current estimates or depreciation method are no longer appropriate. Changes in estimates are accounted for on a prospective basis.

In order to determine whether an expenditure should be capitalized or expensed, the expenditure must be evaluated based on the criteria discussed below. Subject to the threshold levels outlined in **Appendix A**, expenditures that meet the definition of an asset as well as a capital asset will be capitalized, while all remaining expenditures will be expensed. Below are the two definitions which must be met in order for an expenditure to be capitalized:

7.1.1 **Assets** are economic resources controlled by an entity from which future economic benefits may be obtained. Assets have three essential characteristics:

i) they embody a probable future benefit that involves a capacity, singly or in combination with other assets, to contribute directly or indirectly to future net cash inflows;
ii) the entity can obtain the benefit and control others' access to the benefit; and
iii) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

7.1.2 **Capital assets** are expenditures for which the future benefits to the Corporation extend over a period greater than one year. Capital assets comprise property, plant and equipment and intangible assets. Property, plant and equipment consists typically of long-lived tangible assets used to create and distribute an entity's products and services and include land and land improvements, buildings, machinery and equipment, and furniture and fixtures. Intangible assets are assets that lack physical substance.

For additional guidance, **Appendix B – Decision Tree** illustrates the criteria that must be met in order for expenditures to be capitalized. Expenditures not meeting the criteria will be expensed in the period incurred. Additionally, **Appendix C** includes excerpts from the OEB AP Handbook outlining capital asset and expense account definitions. A review of these definitions provides practical references and examples to assist in the classification of various expenditures.

For complex transactions and when capital/operating decisions may be ambiguous, the Business Units will consult with the Finance group.

7.2 Betterments versus Repairs

When expenditures are incurred relating to existing capital assets, they should be evaluated against the criteria outlined below to determine whether the expenditure should be classified as a betterment or a repair. ***Expenditures that meet the definition of a betterment will be capitalized while expenditures that meet the definition of a repair will be expensed. If a cost has the attributes of both a repair and a betterment, the portion considered to be betterment will be included in the cost of the capital asset.***

7.2.1 **Betterments** are costs incurred to enhance the service potential of an existing capital asset. The service potential of an existing capital asset may be enhanced when:

i) there is an increase in the previously assessed physical output or service capacity;
ii) associated operating costs are lowered;
iii) the life or useful life is extended; or
iv) the quality of output is improved.

7.2.2 **Repairs** are costs incurred in the maintenance of the service potential of a capital asset. Frequently referred to as operating expenses or maintenance expenses, they are costs incurred more or less on a continuous basis to keep the capital asset in normal operating condition, but do not improve the value of the asset, nor prolong its life appreciably.

Operating expenses or maintenance expenses are the result of an activity that encompasses actions of a detective, preventive, and/or monitoring nature. They are normally planned or scheduled. They can also be reactionary, in response to an unscheduled breakdown in service function.

For those instances when professional judgement has to be exercised to determine the proper classification of the Corporation's expenditures, the Business Units will confirm the classification as a betterment or repair with the Finance group.

8 ASSET COST COMPONENTS

8.1 Once it has been determined that an asset can be capitalized, below are the amounts that can be included in the cost of a capital asset:

i) A capital asset should be recognized at cost. Capital asset cost is the amount of consideration given 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 assets including installing it at the location and in the condition necessary for the intended use. This would also include any borrowing costs and includes AFUDC captured in CWIP.

The AP Handbook provides for the inclusion of AFUDC when capitalizing CWIP, until such time the asset is substantially complete. The interest rate for capitalization is prescribed by the OEB and modified on a periodic basis and is applied to the eligible CWIP balance on a simple interest basis.

ii) For purchased capital assets, cost would include the purchase price and other acquisition costs, such as: brokers' commissions; installation costs including architectural, design and engineering fees; legal fees; survey costs; site preparation costs; freight charges; transportation insurance costs; duties; testing and preparation charges; and option costs when an option is exercised.

iii) For an electrical plant that is constructed, construction costs should include where applicable: the cost of labour; materials and supplies; transportation; work done by others for the utility; damages incurred in the construction work; privileges and permits; special machinery services; allowance for funds used during construction; and such portion of general engineering, administrative salaries and expenses, insurance, taxes and other similar items as may be properly included in construction.

8.2 Burdens

Four burden rates are specifically analyzed below with respect to the asset cost:

8.2.1 Time-sheeting of Indirect Labour

One of the methods of capitalizing labour costs is to allocate employee labour costs through the process of time-sheeting of indirect labour. Field crews are supported, supervised and guided by those employees whose personnel costs are included in indirect labour.

The process of capitalizing costs of indirect labour includes labour costing (i.e. time-sheeting) which differentiates the time spent between capital, operating, and "blended" activities (i.e. a mix of capital and operating), in order to appropriately allocate costs across projects based on identified cost drivers.

Once time-sheeted hours are applied to specific activities, the calculated cost will be allocated to capital expenditures, operating expenses, or a blend of both based on the nature of the activity. Costs identified as capital or costs that are designated as capital in nature within a blend activity will be mapped to construction work-in-progress ("CWIP"), while costs identified as operating or costs that are designated as operating in nature within a blend activity will be mapped to operating expense.

8.2.2 Standard labour rate

Another method of capitalizing labour costs is to track direct labour costs for various employees and apply a SLR to time recorded to various jobs. There are three broad direct labour categories within the group of employees who currently submit time-sheets for direct labour and for whom SLR's are calculated: inside workers, outside shift workers and outside hourly workers.

The SLRs are calculated by dividing the total employee burden (i.e. employee's total compensation, including various types of benefits) by the total available hours (i.e. hours available for work during the course of the year on capital projects) for each SLR category. The total available hours consist of: a) the total working days in a year less b) leaves (such as vacation and statutory holidays) as well as c) various unproductive time (such as safety training, inclement weather, etc.).

All existing elements of employee burden are capitalized since these costs are all permissible as capital expense elements, however, adjustments are made to the pool of available hours related to various unproductive factors that should not be considered. Such unproductive factors to be removed from the SLR calculation include: meetings, training, modified duty time, supervisory relief time and overtime in lieu. Aside from training (which will always be an operating expense), time spent on these activities in relation to capital work will be capitalized through the time-sheeting mechanism.

8.2.3 On-cost

An on-cost charge is applied to all items issued from the Corporation's warehouse. Such items generally include transformers, poles, cables, etc. These items are then installed in their final locations throughout the City of Toronto and are then considered to be in use. If the items issued from the warehouse are associated with capital projects, the on-cost charge is capitalized, whereas if the items issued are associated with operating projects, the on-cost charge is expensed in the period in which it is incurred.

The on-cost charge associates the cost of warehousing and handling to the items themselves. The on-cost rate is calculated as the sum of budgeted expenses in four specific material handling responsibility centers divided by the budgeted dollar value of materials moving through the warehouse in a given year. This rate is then applied to the dollar value of all materials when issued to capital and operating projects.

Some of the budgeted expenses within the material handling responsibility centers are not capitalizable, thus should not be included in the on-cost calculation. The disallowed costs include:

- Payroll related to administrative staff supporting the procurement and warehousing functions;
- Inventory and direct purchases of materials used in the warehouse for internal purposes – i.e. not used for capital projects;
- Utilities and communications related expenses;
- Office supplies used in procurement and warehousing;
- Employee expenses (i.e. reimbursed expenses for employee purchases); and
- Allocated IT charges related to telephone and computing equipment used by the procurement and warehousing departments.

8.2.4 Vehicle Hire Rate

Vehicles used in the construction of capital assets can be capitalized into the item of PP&E. This capitalization is applied to projects based on time-sheets for the use of each vehicle. A VHR is calculated for each vehicle class and applied to the hours time-sheeted to determine the amount capitalized to each project.

The VHRs are calculated by taking the sum of the total operating charges, fuel costs and depreciation, and dividing by the total available vehicle hours for each vehicle class. The total available vehicle hours are based on the number of working days in a year less a factor for vehicle repairs and maintenance. Some of the budgeted expenses are not capitalizable thus should not be included in the VHR calculation.

8.3 Asset retirement cost

The Corporation recognizes a liability, known as an asset retirement obligation, for future removal and handling costs for contamination in distribution equipment and for the future environmental remediation of certain properties. The liability is measured at present value and an offsetting amount is added to the carrying amount of the related asset as asset retirement cost. This cost is depreciated over the useful life of the related asset. Changes to an existing asset retirement obligation are added to or deducted from the cost of the related asset and depreciated prospectively over the remaining useful life of the asset.

9 POLICY ADMINISTRATION OWNERSHIP, APPROVAL AND RESPONSIBILITIES

Policy Owner

9.1 This policy is owned by the *Chief Financial Officer,* who is responsible for:

- Ensuring that this policy is comprehensive, clear and current.
- Ensuring that this policy is implemented and communicated to the departments and staff that are impacted.
- Ensuring consistency between referenced policies and this document.
- Ensuring on-going compliance with this policy.
- Approving any exceptions to this policy, as required.
- Reviewing this policy annually.

Policy Approver

9.2 This policy is approved by the *Policy Administration Steering Committee,* which is responsible for:

- Considering the impact of the policy to the associated risk.
- Reviewing and approving this policy annually.

Directly Responsible Person

9.3 This policy is managed by the *Controller* of each affiliate through *Business Unit Managers and Senior Financial Analysts.*

9.4 The *Affiliate Controller* is responsible for:

- Ensuring that this policy is communicated to the departments and staff that are impacted and that it is implemented.
- Immediately communicating any exceptions or violations of this policy to the *Manager, Financial Reporting* for approval upon review.
- Reviewing this policy annually.

9.5 The *Business Unit Managers* are responsible for:

- Ensuring that this policy is communicated to the staff impacted and that it is implemented.
- Ensuring ongoing compliance with this policy.
- Ensuring that a review of expenditures recorded in CWIP accounts is performed on a regular basis. Expenditures are recorded in CWIP until such time as the project is essentially complete and may be capitalized as allowed by US GAAP. It is expected that Business Unit personnel and Finance staff periodically review this account for stranded costs and other entries that may be capitalized or expensed.
- Ensuring that a review of projects is performed on a regular basis, so that projects that are essentially complete have the status upgraded to “finished” in Ellipse and/or SAP. Updating the status field is the trigger that initiates timely capitalization of costs.
- Immediately communicating any exceptions or violations of this policy to the *Senior Financial Analysts*.

9.6 The *Senior Financial Analysts* are responsible for:

- Providing support to the Business Units for proper application of this policy.
- Monitoring compliance with this policy.
- Immediately communicating any exceptions or violations of this policy to the *Finance Manager* and the *Affiliate Controller*.

9.7 The *Supervisor, Financial Reporting* is responsible for:

- Ensuring the policy is maintained and kept up to date.
- Immediately communicating any exceptions or violations of this policy to the *Manager, Financial Reporting*.
- Reviewing this policy annually.

10 POLICY COMMUNICATION

COMMUNICATION TRIGGER	TYPE OF COMMUNICATION	PARTY RESPONSIBLE FOR POLICY COMMUNICATION	AUDIENCE	ACKNOWLEDGEMENT
Policy Change/ Review	Presentation and/or e-mail	Manager, Financial Reporting	Affiliate Controller, Business Unit Managers and Senior Financial Analysts	Sign Off
Policy Change/ Review	Scheduled Meeting Presentation	Business Unit Managers	All affected employees	Sign Off
Policy Update	E-Mail	Manager, Financial Reporting	All affected employees	No
New Hire in Finance	Discussion, e-mail	Immediate Supervisor/Manager	New hire	No

11 POLICY COMPLIANCE AND VIOLATIONS

11.1 All Toronto Hydro employees, officers, directors and affiliates are required to comply with this policy.

11.2 Any employee who fails to comply with this policy could be subject to disciplinary action, up to and including dismissal.

11.3 Failure to comply with this policy could lead to a material misstatement of the Corporation’s expenditures on the financial statements and inaccurate submissions to regulatory agencies. This can result in legal, regulatory and reputational ramifications.

12 RELATED LAWS, REGULATIONS AND DOCUMENTATION

12.1 Refer to ASC 360 “Property, Plant and Equipment”, and Statement of Financial Accounting Concepts No.6 for more definitions and accounting guidelines. These Sections are available from the Finance group.

12.2 Refer to the “Computer Software Capitalization Guidelines” for the recommended accounting treatment of expenditures related to the acquisition and/or development of computer software.

12.3 The following appendices were referenced in this policy:

- Appendix A - Minimum threshold dollar amounts for capitalization and Depreciation rates
- Appendix B - Decision Tree - Classification of an expenditure
- Appendix C - Capital asset and repair and maintenance expense definitions - Excerpts from the OEB AP Handbook

These appendices can be found on the Toronto Hydro Plugged In intranet site at http://pluggedin.torontohydro.com/policy/Pages/FinancePolicies.aspx.

OVERHEAD EXPENSE

Appendix 2-DA of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013) (the "Filing Requirements") requires the presentation of changes in the capitalization of overhead costs under modified International Financial Reporting Standards ("mIFRS") and the applicant's previous accounting standard. Toronto Hydro has not filed this Appendix because there are no differences between the capitalization of overhead expenditures upon adoption of mIFRS for the 2014 bridge and 2015 test years.

BACKGROUND

As noted in EB-2010-0142 Exhibit Q1, Tab 1, Schedule 1, Toronto Hydro commenced its IFRS conversion project in 2007 with the intention of converting to IFRS January 1, 2011. However, given uncertainty around the timing, scope and potential adoption of a rate-regulated accounting standard under IFRS, Toronto Hydro decided to file its rate application for 2011 in accordance with the Canadian Generally Accepted Accounting Principles ("CGAAP") in use at that time.

Toronto Hydro determined that certain changes in accounting estimates were required to be applied under CGAAP as additional and more relevant information had been made available through the IFRS project. Toronto Hydro's external auditor acknowledged the appropriateness of prospective application of the changes in accounting estimates effective January 1, 2011 under CGAAP.[1] The changes related to the manner in which Toronto Hydro records and accounts for its property, plant and equipment and were filed as an Accounting Update to the 2011 application.[2]

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[1] Toronto Hydro Corporation Consolidated Financial Statements, December 31, 2011.
[2] EB-2010-0142, Application and Evidence (February 9, 2011), Exhibit Q1, Tab 2, Schedule 1.

As a result of the changes adopted under CGAAP, there are no differences between the capitalization of overhead expenditures upon adoption of MIFRS for the 2014 bridge and 2015 test years. Consequently, Toronto Hydro has not completed OEB Appendix 2-DA as part of this application. Refer to EB-2010-0142 Exhibit Q1, Tab 2, Schedule 1 for a description and quantification of the changes in the capitalization of overhead expenses applied prospectively under CGAAP commencing January 1, 2011.

COST OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING FACILITIES

Section 2.5.2.5 of the OEB's Filing Requirements for Electricity Distributor Rate Applications (July 17, 2013) (the "Filing Requirements"), contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments, as described in section 79.1 of the *Ontario Energy Board Act, 1998* (the "Act") and Regulation 330/09 (O. Reg. 330/09)[1] made under the Act.

Costs incurred by a distributor, in accordance with the cost responsibility rules in the OEB's Distribution System Code, for the purpose of connecting or enabling the connection of a Renewable Energy Generation ("REG") facility to its distribution system are considered to be eligible investments for the purpose of provincial rate recovery under s. 79.1 of the Act.[2]

1. REG CONNECTIONS

There is significant renewable generation activity across Toronto Hydro's distribution system. As of May 31, 2014, Toronto Hydro has connected over 860 renewable generation projects representing over 29 MW of capacity, and has undertaken approximately 325 MW of pre-assessment capacity reviews. Toronto Hydro expects to connect approximately 972 renewable energy generation facilities during the 2015 to 2019 rate period, with a corresponding capacity of 148.9 MW. In summary, by the end of 2019, the utility anticipates to have almost 2000 renewable generation facilities, with a corresponding capacity of approximately 203 MW, connected to its distribution system.

[1] O. Reg. 330/09.
[2] O. Reg. 330/09, at s. 1(2).

Some renewable generation projects are currently unable to connect due to interconnection constraints either at transmission level or distribution level. These interconnection constraints are short circuit capacity, thermal capacity or reverse power flow issues associated with legacy system design or legacy equipment. The breaker upgrades presently underway by Hydro One Networks Inc. ("HONI") are expected to remove constraints at the transmission level, and to be completed by end of 2014.

2. ELIGIBLE INVESTMENTS SUMMARY

To address interconnection constraints at the distribution level, Toronto Hydro proposes to undertake a number of Renewable Enabling Improvement ("REI") investments as part of its 2015 to 2019 Distribution System Plan ("DSP"), which is filed at Exhibit 2B.

2.1. Generation Protection, Monitoring & Control

- **Advanced Protection System**: To enable more renewable generation projects to connect, a high speed protection scheme has been developed for implementation on station buses with short circuit constraints. This advanced protection, monitoring and control system uses a high speed communication network with the associated protective equipment to isolate the generator from the distribution system before the main circuit breakers operate, thus maintaining system integrity for upstream customers. For additional details refer to the Generation Protection Control and Monitoring Program (Exhibit 2B, E5.5) in the DSP.
- **Installation of Bus-Tie Reactors**: Bus-tie reactors lower the short circuit current on the station bus and distribution system by insertion of an impedance at the bus-tie point. This method of fault mitigation has been successfully applied by Powerstream and HONI. Toronto Hydro proposes to work with HONI to install a bus tie reactor at Richview TS to eliminate the existing fault current constraint, which will enable renewable generation connections which at present cannot

proceed. For additional details refer to the Generation Protection Control and Monitoring Program (Exhibit 2B, E5.5) in the DSP.

- **Remote Monitoring and Control of Generation (SCADA)**: Toronto Hydro requires real-time monitoring and control of renewable generation resources via communication networks with the utility's supervisory control and data acquisition ("SCADA") system to enable safe operation of the distribution system and feeder management of bi-directional distribution grid flows. The system has the ability to forecast resources and coordinate with Toronto Hydro's distribution outage management system, thereby enabling greater penetration of renewable generation by providing real-time visibility. Toronto Hydro's requirement for monitoring and control is modelled after requirements developed by the Independent Electricity System Operator ("IESO"). Consistent with the Distribution System Code ("DSC"), the costs associated with this investment program pertains only to renewable generation resources, as conventional generation projects bear the cost of monitoring and control requirements. For additional details refer to the Generation Protection, Control and Monitoring Program (Exhibit 2B, E5.5) in the DSP.

2.2. Energy Storage

- Toronto Hydro plans to deploy 24 energy storage systems at various strategic locations across the distribution system. These energy storage systems represent a total aggregated peak capacity of 4.4MW and aggregated energy capacity of 10MWh. Toronto Hydro's infrastructure was not designed to accommodate two-way, variable renewable generation resources and these energy storage systems will balance energy flows in specific areas, allowing renewable generation connections to proceed and helping defer the need for conventional infrastructure upgrades. For additional details refer to the Energy Storage Program in the DSP (Exhibit 2B, E7.11).

The Ontario Power Authority ("OPA") reviewed Toronto Hydro's plans for REG investments and found that: 1) the utility's plans are reasonably consistent with the OPA's information regarding REG, and 2) that the investments support and enable the connection of additional REG, which enhances the ability of local customers and proponents to participate in ongoing renewable programs, while contributing to the supply diversity within the Integrated Regional Resource Plan ("IRRP") study for the Central Toronto region. For more information, please refer to the OPA Comment Letter filed at Exhibit 2B, Section B.

3. ELIGIBLE INVESTMENTS COSTS

Table 1 below summarizes the costs associated with REI investments over the 2015 to 2019 rate period. Toronto Hydro is not proposing any specific Renewable Expansion ("RE") investments during the period 2015 – 2019. However, Toronto Hydro notes that certain investments in its Station Expansion program (Exhibit 2B, E7.9) are expected to improve the utility's ability to connect REG facilities.

Table 1: Renewable Enabling Improvements (REI) from 2015 to 2019 ($ Millions)

Capital Program	2015	2016	2017	2018	2019
Generation Protection Control and Monitoring	6.12	5.19	3.26	2.10	2.02
Energy Storage	0.54	1.09	2.16	3.24	3.78
Totals	**6.66**	**6.27**	**5.43**	**5.34**	**5.79**

/C

4. PROVINCIAL RATE PROTECTION

In accordance with s. 2.5.2.5 of Filing Requirements, Toronto Hydro applied the six percent direct benefit assumption provided by the OEB with respect to REI investments to calculate the provincial rate protection amounts summarized below in Table 2. A more detailed breakdown of these figures is provided in the OEB Appendices 2-FA and 2-FB at Exhibit 2A, Tab 8, Schedules 2 and 3, respectively. (Note that Appendix 2-FC provided in Schedule 4 is not applicable).

Table 2: Provincial Rate Protection Amounts from 2015 to 2019 ($Millions)

Year	2015	2016	2017	2018	2019
Provincial Rate Protection	0.31	1.00	1.69	2.31	2.93

/C

OEB Appendix 2-FA
Renewable Generation Connection Investment Summary (over the rate setting period)

Enter the details of the Renewable Generation Connection projects as described in Section 2.5.2.5 of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.

For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB

For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments.

Part A

REI Investments (Direct Benefit at 6%)	2015	2016	2017	2018	2019	
Project 1						
Leslie BY Bus Adv. P/M/C						
Capital Costs	$212,609	$134,771	$133,137	$133,467	$26,532	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 2						
Richview BY Bus Tie Reactors						
Capital Costs	$31,891	$269,541	$234,322	$0	$0	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 3						
Wiltshire TS Adv. P/M/C						
Capital Costs	$382,696	$129,380	$127,812	$128,129	$127,352	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 4						
Basin TS Adv. P/M/C						
Capital Costs	$159,457	$134,771	$133,137	$106,774	$0	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 5						
Existing DG Connections M/C						
Capital Costs	$1,071,548	$1,086,790	$1,044,989	$0	$0	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 6						
New DG Connections M/C						
Capital Costs	$2,371,012	$1,407,652	$1,483,299	$1,626,380	$1,755,085	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Project 7						
DG SCADA Management						
Capital Costs	$1,887,974	$2,022,646	$106,510	$106,774	$106,127	/C
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	

Project 8						
Energy Storage						
Capital Costs	$541,684	$1,087,616	$2,164,315	$3,239,819	$3,777,405	**/C**
OM&A (Start-Up)	$0	$0	$0	$0	$0	
OM&A (Ongoing)	$0	$0	$0	$0	$0	
Total Capital Costs	**$ 6,658,870**	**$ 6,273,166**	**$ 5,427,521**	**$ 5,341,343**	**$ 5,792,500**	**/C**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

Part B

Expansion Investments (Direct Benefit at 17%)	**2015**	**2016**	**2017**	**2018**	**2019**
Project 1					
Project Description					
Capital Costs	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

OEB Appendix 2-FB
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

		2015 Test Year			2016			2017			2018			2019		
			Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
		Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)		$ 3,262,846	$ 195,771	$ 3,067,075	$ 9,466,367	$ 567,982	$ 8,898,385	$ 14,807,885	$ 888,473	$ 13,919,412	$ 19,458,797	$ 1,167,528	$ 18,291,269	$ 24,073,171	$ 1,444,390	$ 22,628,781
Incremental OM&A (on-going, N/A for Provincial Recovery)		$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)		$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA	7.99%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base			$ 195,771	$ 3,067,075		$ 567,982	$ 8,898,385		$ 888,473	$ 13,919,412		$ 1,167,528	$ 18,291,269		$ 1,444,390	$ 22,628,781
Deemed ST Debt	4%		$ 7,831	$ 122,683		$ 22,719	$ 355,935		$ 35,539	$ 556,776		$ 46,701	$ 731,651		$ 57,776	$ 905,151
Deemed LT Debt	56%		$ 109,632	$ 1,717,562		$ 318,070	$ 4,983,095		$ 497,545	$ 7,794,871		$ 653,816	$ 10,243,111		$ 808,859	$ 12,672,117
Deemed Equity	40%		$ 78,308	$ 1,226,830		$ 227,193	$ 3,559,354		$ 355,389	$ 5,567,765		$ 467,011	$ 7,316,508		$ 577,756	$ 9,051,512
ST Interest	1.38%		$ 108	$ 1,693		$ 314	$ 4,912		$ 490	$ 7,684		$ 644	$ 10,097		$ 797	$ 12,491
LT Interest	4.34%		$ 4,758	$ 74,542		$ 13,804	$ 216,266		$ 21,593	$ 338,297		$ 28,376	$ 444,551		$ 35,104	$ 549,970
ROE	9.30%		$ 7,283	$ 114,095		$ 21,129	$ 331,020		$ 33,051	$ 517,802		$ 43,432	$ 680,435		$ 53,731	$ 841,791
Cost of Capital Total			$ 12,149	$ 190,330		$ 35,247	$ 552,198		$ 55,135	$ 863,783		$ 72,452	$ 1,135,083		$ 89,633	$ 1,404,252
OM&A			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization		$ 133,177	$ 7,991	$ 125,187	$ 391,818	$ 23,509	$ 368,309	$ 625,832	$ 37,550	$ 588,282	$ 841,209	$ 50,473	$ 790,737	$ 1,063,886	$ 63,833	$ 1,000,053
Grossed-up PILs			-$ 255	-$ 3,999		$ 5,031	$ 78,819		$ 15,277	$ 239,338		$ 24,493	$ 383,725		$ 33,773	$ 529,104
Revenue Requirement			$ 19,884	$ 311,518		$ 63,787	$ 999,326		$ 107,962	$ 1,691,403		$ 147,418	$ 2,309,544		$ 187,239	$ 2,933,408
Provincial Rate Protection				$ 311,518			$ 999,326			$ 1,691,403			$ 2,309,544			$ 2,933,408
Monthly Amount Paid by IESO				$ 25,960			$ 83,277			$ 140,950			$ 192,462			$ 244,451

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis
Note 2: For the Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2015		2016		2017			2018			2019	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
							Total			Total		
Net Income - ROE on Rate Base	$ 7,283	$ 114,095	$ 21,129	$ 331,020	$ 33,051	$ 517,802		$ 43,432	$ 680,435		$ 53,731	$ 841,791
Amortization (6% DB and 94% P)	$ 7,991	$ 125,187	$ 23,509	$ 368,309	$ 37,550	$ 588,282		$ 50,473	$ 790,737		$ 63,833	$ 1,000,053
CCA (6% DB and 94% P)	-$ 15,981	-$ 250,374	-$ 30,684	-$ 480,717	-$ 28,229	-$ 442,260		-$ 25,971	-$ 406,879		-$ 23,893	-$ 374,329
Taxable income	-$ 708	-$ 11,092	$ 13,954	$ 218,612	$ 42,372	$ 663,824		$ 67,934	$ 1,064,293		$ 93,671	$ 1,467,515
Tax Rate (to be entered)	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%	26.50%		26.50%	26.50%
Income Taxes Payable	-$ 187.61	-$ 2,939.26	$ 3,697.80	$ 57,932.13	$ 11,228.52	$ 175,913.45		$ 18,002.40	$ 282,037.60		$ 24,822.86	$ 388,891.43
Gross Up												
Income Taxes Payable	-$ 255.25	-$ 3,998.99	$ 5,031.01	$ 78,819.22	$ 15,276.89	$ 239,338.02		$ 24,493.06	$ 383,724.62		$ 33,772.59	$ 529,103.99
Grossed Up PILs	-$ 255	-$ 3,999	$ 5,031	$ 78,819	$ 15,277	$ 239,338		$ 24,493	$ 383,725		$ 33,773	$ 529,104

/C

Net Fixed Assets

		2015	2016	2017	2018	2019
Enter applicable amortization in years:	25					
Opening Gross Fixed Assets			$ 6,658,870	$ 12,932,036	$ 18,359,557	$ 23,700,900
Gross Capital Additions		$ 6,658,870	$ 6,273,166	$ 5,427,521	$ 5,341,343	$ 5,792,500
Closing Gross Fixed Assets		$ 6,658,870	$ 12,932,036	$ 18,359,557	$ 23,700,900	$ 29,493,401
Opening Accumulated Amortization			$ 133,177	$ 524,996	$ 1,150,827	$ 1,992,037
Current Year Amortization (before additions)			$ 266,355	$ 517,281	$ 734,382	$ 948,036
Additions (half year)		$ 133,177	$ 125,463	$ 108,550	$ 106,827	$ 115,850
Closing Accumulated Amortization		$ 133,177	$ 524,996	$ 1,150,827	$ 1,992,037	$ 3,055,923
Opening Net Fixed Assets		$ -	$ 6,525,692	$ 12,407,041	$ 17,208,730	$ 21,708,864
Closing Net Fixed Assets		$ 6,525,692	$ 12,407,041	$ 17,208,730	$ 21,708,864	$ 26,437,478
Average Net Fixed Assets		$ 3,262,846	$ 9,466,367	$ 14,807,885	$ 19,458,797	$ 24,073,171

/C

UCC for PILs Calculation

		2015	2016	2017	2018	2019
Opening UCC			$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775
Capital Additions (from Appendix 2-FA)		$ 6,658,870	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ 6,658,870	$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775
Half Year Rule (1/2 Additions - Disposals)		$ 3,329,435	$ -	$ -	$ -	$ -
Reduced UCC		$ 3,329,435	$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ 266,355	$ 511,401	$ 470,489	$ 432,850	$ 398,222
Closing UCC		$ 6,392,515	$ 5,881,114	$ 5,410,625	$ 4,977,775	$ 4,579,553

OEB Appendix 2-FC
Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.

Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.

Rate Riders are not calculated for Test Year as these assets and costs are already in the distributors rate base.

	2015 Test Year			2016			2017			2018			2019		
	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis
Note 2: For the Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2015		2016		2017			2018			2019	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
							Total			Total		
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Amortization (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
CCA (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Tax Rate (to be entered)												
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Gross Up												
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -

Net Fixed Assets		2015	2016	2017	2018	2019
Enter applicable amortization in years:	25					
Opening Gross Fixed Assets			$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization			$ -	$ -	$ -	$ -
Current Year Amortization (before additions)			$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2015	2016	2017	2018	2019
Opening UCC			$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -

ICM TRUE-UP – DEFERRAL PROPOSAL

1. INTRODUCTION

This schedule outlines Toronto Hydro's proposal for the treatment of its 2012-2014 Incremental Capital Module ("ICM") true-up.

In its Accounting Order in Toronto Hydro's 2012-2014 ICM application, the Ontario Energy Board ("OEB") ordered the utility to true-up the revenue requirement which was used to derive the ICM rate rider revenues for the ICM funding at a future date, on the basis of total annual revenue requirement impacts based on the actual in-service assets of OEB-approved ICM segments.[1] Toronto Hydro's accounting process is not expected to have a final report of actual in-service additions ("ISAs") for 2014 until the second quarter of 2015. Therefore, Toronto Hydro proposes to defer the ICM true-up and bring forward a separate application in 2015, once actual ICM amounts are known.

2. PROPOSED APPROACH TO TRUE-UP

Toronto Hydro's 2012-2014 ICM application provided a detailed view into the utility's planned capital work based on the following hierarchy:

- Projects (10): the highest-level of work that can consist of one or more segments;
- Segments (24): a medium-level of work that consists of multiple jobs, and
- Jobs (hundreds): the most granular and detailed description of Toronto Hydro's capital activities.

In its Partial Decision and Order, the OEB approved Toronto Hydro's capital program at the level of the ICM segments[3] filed by the utility, with rate riders determined for each year calculated using a forecast of ISAs for the funded ICM segments. For example, "B1

[1] EB-2012-0064, Rate Order, 9 May 2013, pages 2-3.
[3] As discussed in Exhibit 2B, ICM capital segments are comparable to DSP programs in this application.

Underground Infrastructure" and "B2 Paper Insulated Lead Covered Cable – Piece Outs and Leakers" were both approved ICM segments. Toronto Hydro's rate riders were determined based on the cumulative forecast ISAs of the segments that were approved for rate rider funding.

The OEB contemplated the need to true-up to accommodate differences between forecast and actual expenditures at the segment level. Individual jobs within each segment may vary for a number of reasons, including (i) difference between cost forecast and actuals; (ii) prudent addition and removal of jobs from segments, (iii) the fact that jobs may come into service in a different calendar year than originally forecast.[4]

Upon determining final expenditures and ISAs by segment, Toronto Hydro proposes to complete the ICM workforms using these actual in service amounts, as stipulated in the OEB's Accounting Order. On an annual basis, the recalculated actual revenue requirement will be compared to revenues accrued through the respective rate rider to determine variances due to under-spend or prudent over-spend. The OEB determined that these variances would be returned to, or collected from, customers through a separate rate rider.

The steps described above are necessary precursors to truing-up ICM revenue requirement and actual ISAs. Toronto Hydro does not expect to be able to determine the required 2014 actual expenditures or ISAs in concordance with the likely timeframe of this proceeding. Toronto Hydro therefore submits that the true-up of the 2012-2014 ICM activities is most appropriately undertaken in a separate proceeding from this application, following the determination of actual expenditures and ISAs for the full 2012-2014 ICM period.

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[4] For a discussion of operational factors that may lead to variances between planned and actual work, please see the "Execution Challenges" section in Exhibit 1B, Tab 1, Schedule 4, Appendix A (Execution Challenges)

SERVICE QUALITY PERFORMANCE

Toronto Hydro's service quality performance has been steady in most metrics over the five previous years, meeting or exceeding OEB standards in all areas, with the exception of the Appointment Rescheduling and Emergency Response metrics. A summary table of Toronto Hydro's performance, OEB Appendix 2G, is provided in Tab 10, Schedule 3. Detailed explanations of notable variances and results below OEB standards are described below.

1. APPOINTMENT RESCHEDULING

This metric requires utilities to contact a customer in advance of missing an appointment and reschedule a replacement appointment within two business days. As discussed below, Toronto Hydro did not meet the OEB's 100% standard for this metric in 2009, 2012, or 2013. When these three years are combined, Toronto Hydro had 50,251 customer appointments, 235 of which were missed, and of these only three were not /C rescheduled within two business days.

Toronto Hydro's results under this metric are more a function of the mathematical data than an underlying performance issue. Toronto Hydro focuses its efforts primarily to meet as many appointments as possible, such that very few are actually missed on an annual basis. When one of these very few missed appointments is subsequently not rescheduled in accordance with the OEB's performance metrics, it results in a fairly dramatic impact in percentage terms. For example, in 2009 of 23,027 total appointments with customers, only 82 were missed, of which only 1 was not rescheduled within the parameters of this metrics. Similarly, in 2012 and 2013, of 12,547 and 14,677 total appointments with customers, only 91 and 61 were missed, of which only 1 each were /C not properly rescheduled. As shown in Table 1 below, the number of appointments not rescheduled within the parameters of the Appointment Rescheduling metric are immaterial as a percentage of the total.

Table 1: Appointments Rescheduling Summary

Year	Total Appointments	Appointments Missed	Appointments Not Rescheduled within 2 business days	Appointment Rescheduling ESQR	Appointments Not Rescheduled as a percentage of Total Appointments
2009	23,027	82	1	98.8%	99.9999%
2012	12,547	91	1	98.9%	99.9999%
2013	14,677	61	1	98.4%	99.9999%

/C

2. TELEPHONE ACCESSIBILITY

This metric requires utilities to respond to a customer's call within 30 seconds at least 65% of the time. Toronto Hydro has consistently exceeded this standard. The utility did experience a slight decline in performance in 2010 and 2011. This was primarily a result of pre- and post-business activities and training associated with converting to a new Customer Information System. In 2012, Toronto Hydro introduced a new customer care business model to better serve customer needs and improve efficiency by directing residential calls and simple clerical tasks to an external call centre, while internally retaining the complex work associated with business customers. During the three-month transition to this new model, the service level response time was temporarily affected but continued to exceed the OEB standard. This period is reflected in the annual results.

3. WRITTEN INQUIRY RESPONSE

The written response metric requires utilities to respond to customers' written inquiries within ten days at least 80% of the time. Toronto Hydro has consistently exceeded this standard, but did experience a slight decline in performance in 2012. The transition to a new customer care business model, combined with a large increase in inquiries in the month of November regarding an issue related to ePost (an external electronic bill presentment service) slightly affected these annual results, which still exceed the OEB standard.

4. EMERGENCY RESPONSE

The Emergency Response metric requires utilities to respond to emergency calls within one hour in urban settings at least 80% of the time. Toronto Hydro exceeded this metric in 2010 and 2011, but had difficulties meeting it in 2009, 2012 and 2013. In these years, Toronto Hydro underperformed by between 0.5% and 7.5%. In all three years, but in 2012 and 2013 in particular, the major contributing factor to underperformance were the timing and severity of Major Event Days ("MEDs") – typically storms – which may not allow for a timely response to all (often simultaneous) emergency calls.

In 2012, the weather originating from Tropical Storm Sandy alone was responsible for 8% of all emergency incidents in 2012. Given the severity of the storm, THESL was only able to achieve a response target of 20% during this event. In addition, five of the eight MEDs in 2012 occurred after-hours, during which fewer resources were available for immediate dispatch, and once these were fully-engaged there was an unavoidable time delay before additional crews could be mobilized. With even a portion of these MEDs excluded or normalized, THESL's performance would have exceeded the 80% standard in 2012.

Similarly, in 2013 Toronto Hydro's underperformance was also the result of MEDs (8 of 10 of which occurred after hours) particularly the ice storm in December. This five-day period alone accounted for 16% of the yearly volume of emergency events, meaning that Toronto Hydro achieved an hourly response rate of 15% during the month of December. As a result of the ice storm, Toronto Hydro's annual year-to-date performance dropped from 86% as of December 21 to 74% by December 31, only ten days later.

In addition to emergencies originating from Police, Fire, or Ambulance (as per the definition of this metric), Toronto Hydro responds with the same priority to any emergency situation reported by any other member of the public. Therefore, the number of true emergency incidents (i.e., any for which THESL dispatches a crew on an emergency basis) is substantially higher than reported.

Nonetheless, Toronto Hydro is committed to continuing to improve its Emergency Response during the 2015-2019 period, and has planned investments to allow for a more timely response by its emergency response crew. Please refer to Exhibit 4A, Tab 2, Schedule 3 for additional details.

RELIABILITY PERFORMANCE

1. INTRODUCTION

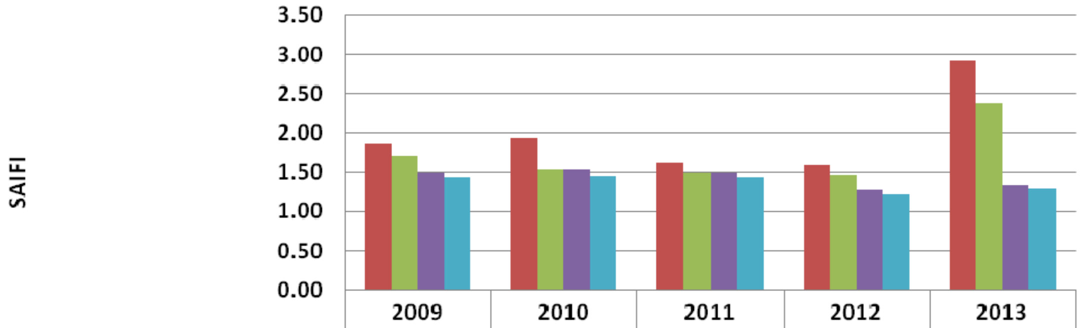
Toronto Hydro tracks reliability performance indicators System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI") in several ways:

1) including all events;
2) excluding Loss of Supply;
3) excluding Major Event Days ("MEDs") and Loss of Supply; and
4) excluding MEDs, Loss of Supply, and Scheduled Outages

Scenarios 1 and 2 provide SAIFI and SAIDI in the filing manner required by OEB Appendix 2-G (Exhibit 2A, Tab 10, Schedule 3). Scenarios 3 and 4 provide SAIFI and SAIDI values by excluding additional externalities and controllable outages, to give a more normalized reflection of total system reliability. Each of these values provides valuable information as to the causes, duration, and frequency of outages within Toronto Hydro's distribution system.

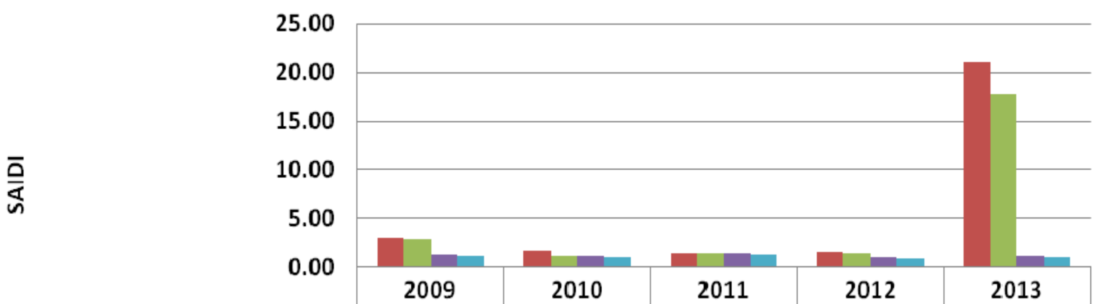
2. SYSTEM OVERVIEW

Figures 1 and 2 below show the system's total SAIFI and SAIDI between 2009 and 2013, respectively under each of the four scenarios. The notable increase in SAIFI and SAIDI in 2013 under scenarios 1 and 2 can be attributed to the flooding of Manby TS in July and the Ice Storm in December, both of which were MEDs. Under scenarios 3 and 4, (which exclude MEDs and other externalities, as well as planned outages), there is actually a slight overall downward trend in both SAIFI and SAIDI, suggesting improving system performance. Toronto Hydro places greater value in these latter scenarios (which exclude MEDs) since they provide a better indication of the performance trend of the system and the impact of recent investments, and are more commonly used across the industry for benchmarking against past performances.



	2009	2010	2011	2012	2013
Total SAIFI	1.86	1.95	1.62	1.60	2.91
SAIFI Excluding LoS	1.71	1.54	1.48	1.47	2.38
SAIFI Excluding MED's and LoS	1.49	1.53	1.48	1.28	1.34
SAIFI Excluding MED's, LoS and Planned Outages	1.44	1.46	1.44	1.22	1.30

Figure 1: System Level SAIFI



	2009	2010	2011	2012	2013
Total SAIDI	2.91	1.66	1.43	1.50	21.07
SAIDI Excluding LoS	2.77	1.19	1.38	1.46	17.70
SAIDI Excluding MED's and LoS	1.24	1.18	1.38	0.99	1.12
SAIDI Excluding MED's, LoS and Planned Outages	1.21	1.02	1.29	0.94	1.05

Figure 2: System Level SAIDI

3. LOSS OF SUPPLY

Loss of Supply events have a significant impact on the overall reliability of Toronto Hydro's distribution system, and being external to Toronto Hydro's operations and control, are generally excluded from a system reliability analysis. In 2013, a total of 54 Loss of Supply events affected the system, with 17 such events occurring in 2012. On a system level, Loss of Supply typically affects up to 13% of the SAIFI and 10% of the SAIDI. Figures 3 and 4 below show the SAIFI and SAIDI system impact due to Loss of Supply.

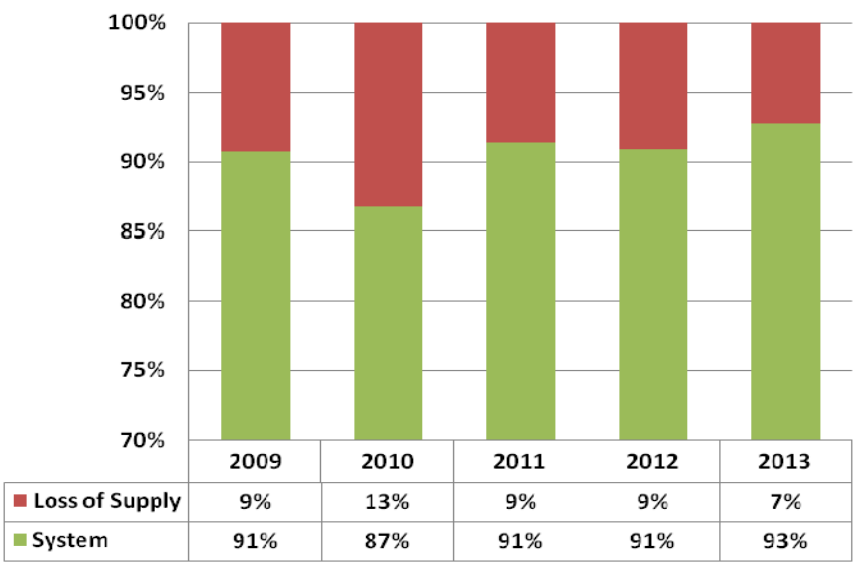


Figure 3: Loss of Supply Impact on Total SAIFI

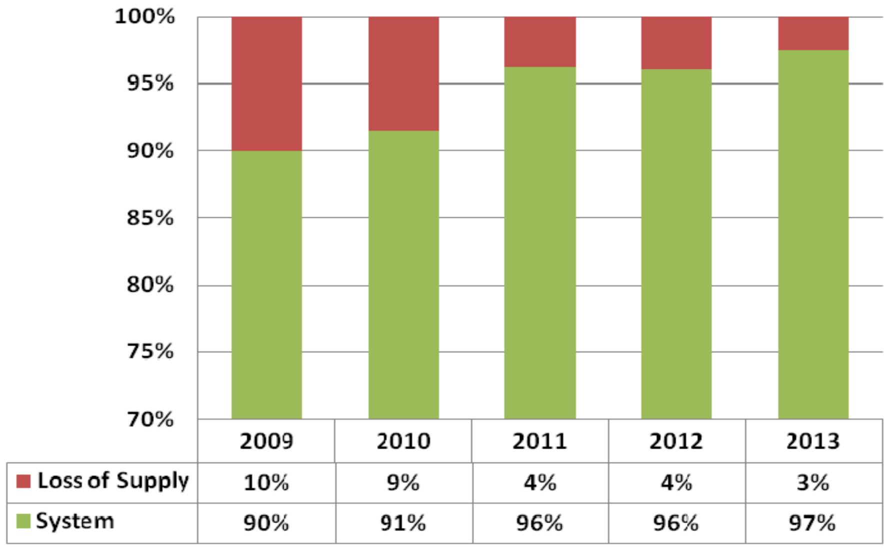


Figure 4: Loss of Supply Impact on Total SAIDI

3.1. Major Event Days

Major Event Days ("MEDs") are defined by the Institute of Electrical and Electronics Engineers ("IEEE") as "events that are beyond the design and/or operational limits of a utility." Similarly to Loss of Supply events, MEDs are generally external to routine utility operation, and in addition, are highly volatile from year to year. The exclusion of MEDs allows a utility to normalize its reliability data to make trending and goal setting possible. MEDs experienced by Toronto Hydro since 2003 are shown in Table 1 below:

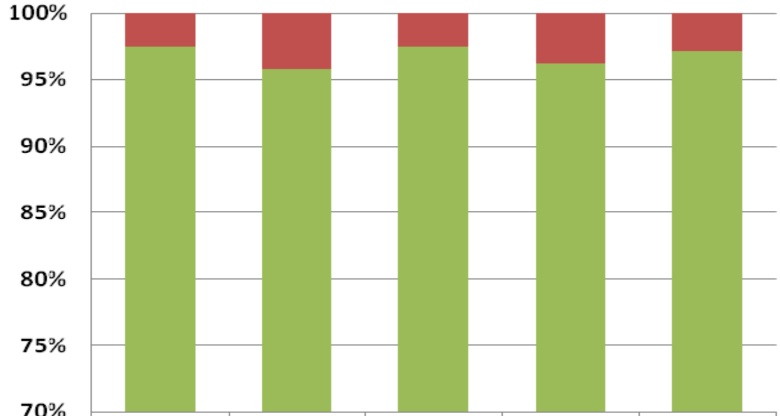
Table 1: Major Event Days

Date	Description	SAIDI
Aug 14 - 15, 2003	Blackout	2 days
Sep 19, 2003	Hurricane Isabel	8.01 minutes
Jul 26, 2005	Loss of Supply to Esplanade TS	6.93 minutes
Aug 19, 2005	Major storm (thunderstorm)	19.16 minutes
Aug 20, 2005	Major storm (thunderstorm)	6.44 minutes
Jul 17, 2006	Major storm (thunderstorm)	12.46 minutes
Aug 21, 2006	Loss of Supply to Scarborough TS	7.30 minutes

Date	Description	SAIDI
Mar 2, 2007	Major ice storm	24.21 minutes
Jun 8, 2007	Major storm (thunderstorm)	11.63 minutes
Jan 15, 2009	Dufferin TS flooding	54.98 minutes
Apr 25, 2009	Major storm (thunderstorm)	12.69 minutes
Aug 20, 2009	Major storm (thunderstorm)	13.69 minutes
Aug 22, 2009	Major storm (thunderstorm)	10.42 minutes
Jul 5, 2010	Loss of Supply to Manby TS	21.61 minutes
Oct 29, 2012	Hurricane Sandy	9.37 minutes
Oct 30, 2012	Hurricane Sandy	18.83 minutes
Jul 8, 2013	Major storm (thunderstorm)	197.26 minutes
Jul 9, 2013	Major storm (thunderstorm)	7.60 minutes
Dec 21, 2013	Freezing Rain Ice Storm	263.90 minutes
Dec 22, 2013	Freezing Rain Ice Storm	683.13 minutes
Dec 23, 2013	Freezing Rain Ice Storm	16.19 minutes
Dec 24, 2013	Freezing Rain Ice Storm	12.30 minutes
Dec 25, 2013	Freezing Rain Ice Storm	7.65 minutes
Dec 26, 2013	Freezing Rain Ice Storm	7.53 minutes

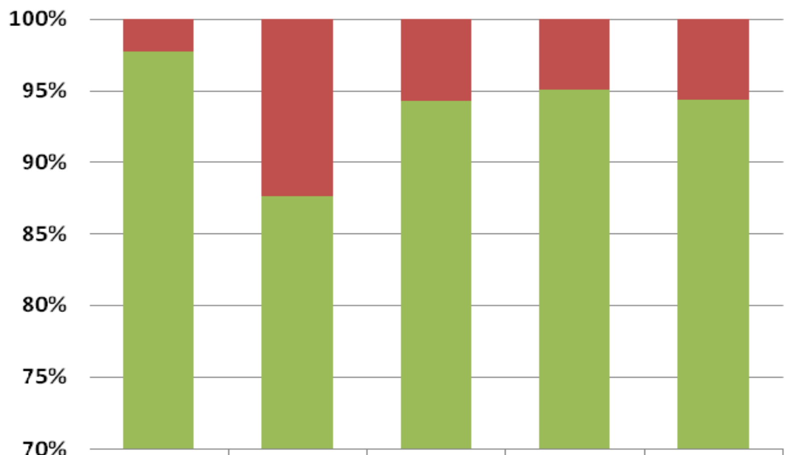
3.2. Scheduled Outages

Scheduled Outages are associated with construction and preventative maintenance activities. Assets that are at risk of failing in the near future may be taken out of service to be repaired or replaced. While this can lead to lengthy outages, the duration of the outage would generally be much shorter than those caused by the asset failing during regular operation. Such planned replacements are also often required to mitigate safety risks to Toronto Hydro's employees. Toronto Hydro provides customers advanced notification of any impending work prior to engaging the project, which gives them the opportunity to plan their activities around the repair work. As planned outages do not reflect the inherent performance of the distribution system, they are typically excluded from reliability analysis.



	1	2	3	4	5
Scheduled Outages	2%	4%	2%	4%	3%
System	98%	96%	98%	96%	97%

Figure 5: Scheduled Outages Impact on Total SAIFI



	1	2	3	4	5
Scheduled Outages	2%	12%	6%	5%	6%
System	98%	88%	94%	95%	94%

Figure 6: Scheduled Outages Impact on Total SAIDI

4. SYSTEM RELIABILITY EXCLUDING LOSS OF SUPPLY, MAJOR EVENT DAYS AND SCHEDULED OUTAGES

As noted above, Toronto Hydro has minimal control over Major Event Days and Loss of Supply events. As a result, these factors are typically excluded from analysis of the overall system performance. In addition, Scheduled Outages are required in order to replace assets that are at their end of life and are not a reflection of distribution system performance. As such, they are also typically excluded from the analysis of the overall system performance. Figures 7, 8, and 9 below show the adjusted SAIFI, SAIDI, and CAIDI (excluding Loss of Supply, MEDs, and Scheduled Outages).

The year over year adjusted values show a steady improvement over the years, with a dramatic improvement in 2012 for both SAIFI and SAIDI. While a part of this is a result of Toronto Hydro's investment strategy, which has focused on replacing old and aging infrastructure and reducing outages caused by defective equipment, the majority of the 2012 improvement can be attributed to favourable weather conditions and a decrease in overall wind speeds. This is further shown in the cause code breakouts in Figures 10 and 11, and highlighted in the weather related breakouts in Figures 12 and 13.

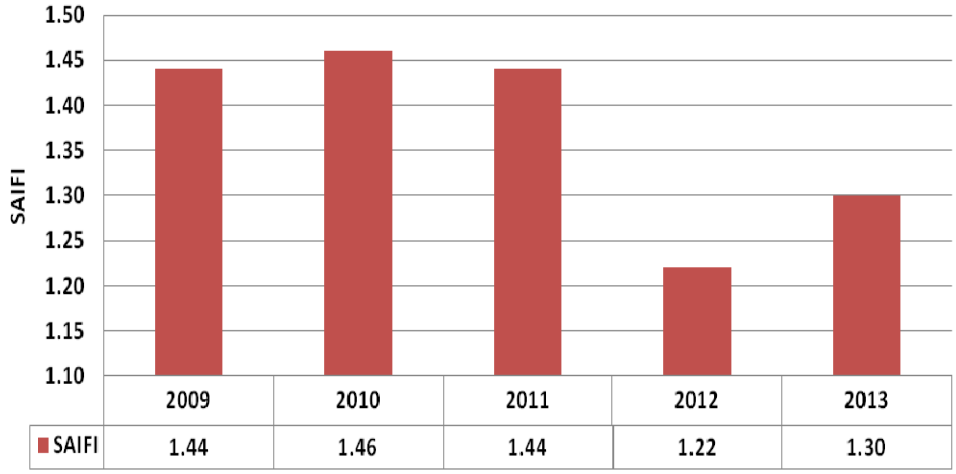


Figure 7: System SAIFI Excluding MEDs, Loss of Supply and Scheduled Outages

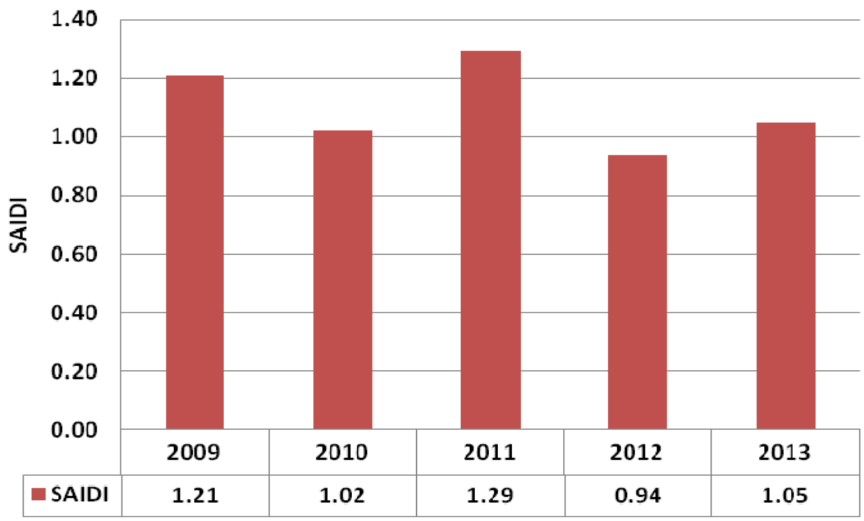


Figure 8: System SAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

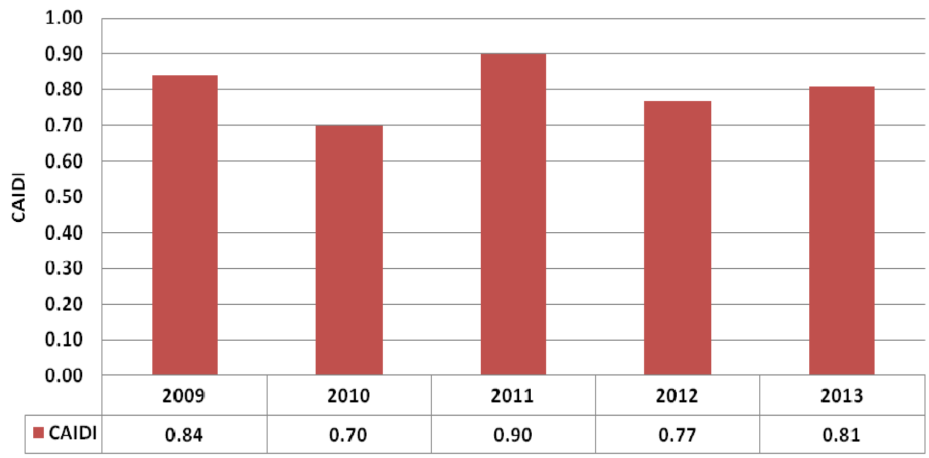
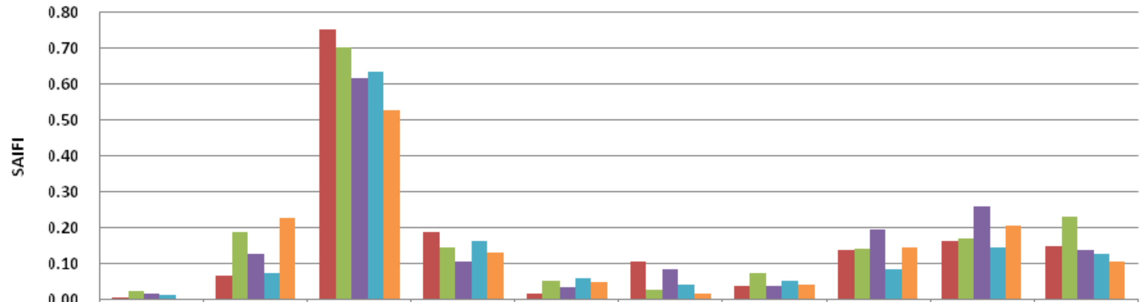


Figure 9: System CAIDI Excluding MEDs, Loss of Supply and Scheduled Outages

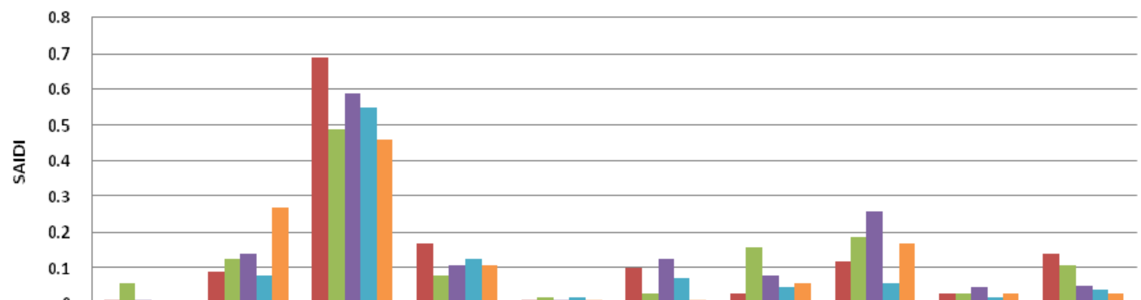
5. CAUSE CODE ANALYSIS

Toronto Hydro tracks causes of service interruptions using the ten primary cause codes as specified in OEB's Reporting and Record Keeping Requirements. Figures 10 and 11 show the reliability performance for SAIFI and SAIDI by cause code from 2009 through 2013. Table 2 shows the percentage contribution of each cause code to overall system SAIFI and SAIDI.



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN	LOSS of SUPPLY
2009	0.01	0.07	0.75	0.19	0.02	0.11	0.04	0.14	0.17	0.15
2010	0.02	0.19	0.70	0.15	0.05	0.03	0.07	0.14	0.17	0.23
2011	0.02	0.13	0.62	0.11	0.03	0.08	0.04	0.19	0.26	0.14
2012	0.01	0.08	0.64	0.16	0.06	0.04	0.05	0.09	0.15	0.13
2013	0.00	0.23	0.53	0.13	0.05	0.02	0.04	0.14	0.20	0.10

Figure 10: SAIFI Cause Code Breakdown (Excluding MEDs)



	ADVERSE ENVIRONMENT	ADVERSE WEATHER	DEFECTIVE EQUIPMENT	FOREIGN INTERFERENCE	HUMAN ELEMENT	LIGHTNING	SCHEDULED OUTAGE	TREE CONTACTS	UNKNOWN	LOSS of SUPPLY
2009	0.01	0.09	0.69	0.17	0.01	0.1	0.03	0.12	0.03	0.14
2010	0.06	0.13	0.49	0.08	0.02	0.03	0.16	0.19	0.03	0.11
2011	0.01	0.14	0.59	0.11	0.01	0.13	0.08	0.26	0.05	0.05
2012	0	0.08	0.55	0.13	0.02	0.07	0.05	0.06	0.02	0.04
2013	0	0.27	0.46	0.11	0.01	0.01	0.06	0.17	0.03	0.03

Figure 11: SAIDI Cause Code Breakdown (Excluding MEDs)

Table 2: Five-Year Average SAIFI and SAIDI Contribution by Cause Code

Cause Code	Contribution % to SAIFI	Contribution % to SAIDI
Defective Equipment	41.1%	44.3%
Unknown	12.0%	2.6%
Loss of Supply*	9.6%	5.9%
Foreign Interference	9.3%	9.4%
Tree Contacts	9.0%	12.8%
Adverse Weather	8.7%	11.3%
Lightning	3.5%	5.2%
Scheduled Outage*	3.2%	6.2%
Human Element	2.7%	1.0%
Adverse Environment	0.8%	1.3%

* Excluded from typical system analysis when demonstrating the true condition of THESL's system

Between 2009 and 2013, defective equipment was the main contributor to SAIFI and SAIDI, at 41.1% and 44.3% respectively. As shown in Figures 10 and 11, the majority of improvement in SAIFI and SAIDI in 2013 over the previous years is in Defective Equipment and, to a lesser extent, Adverse Environment and Lightning. Outages due to Adverse Environment and Lightning are typically not reflective of the condition of the assets in the system, but rather the environmental stresses that the assets experience. Toronto Hydro views the Defective Equipment cause code as a primary indicator of the condition of its distribution system, and tracks this cause code as a measure of continuous improvement over the course of its capital expenditure and maintenance plans. Additional analysis of various relevant cause codes is provided below.

5.1. Weather Impacts

Three cause codes can generally be combined to reflect weather impacts on the system:

(a) Adverse Weather,

(b) Lightning, and

(c) Tree Contacts

Figures 12 and 13 show the cumulative weather reliability impacts on the system.

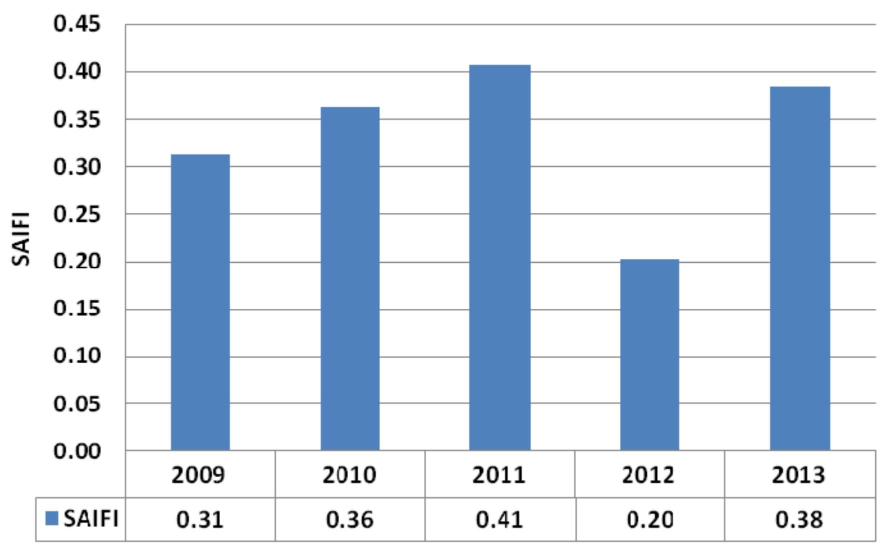


Figure 12: Weather Impacts to SAIFI

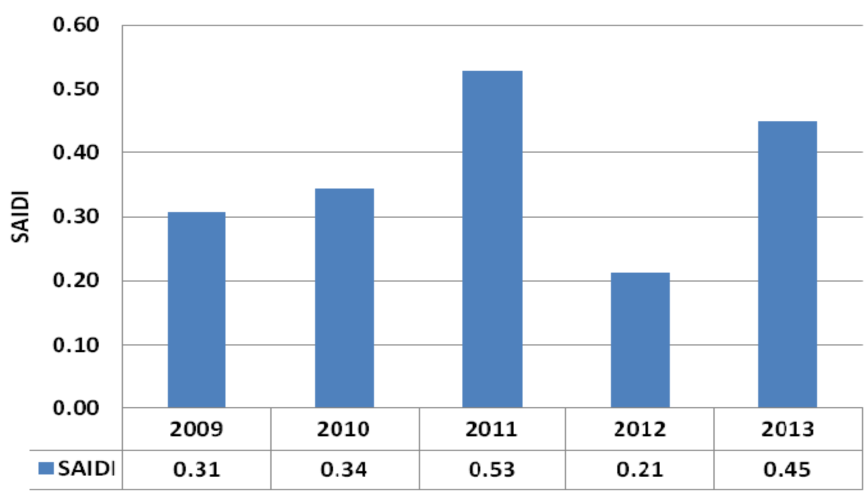
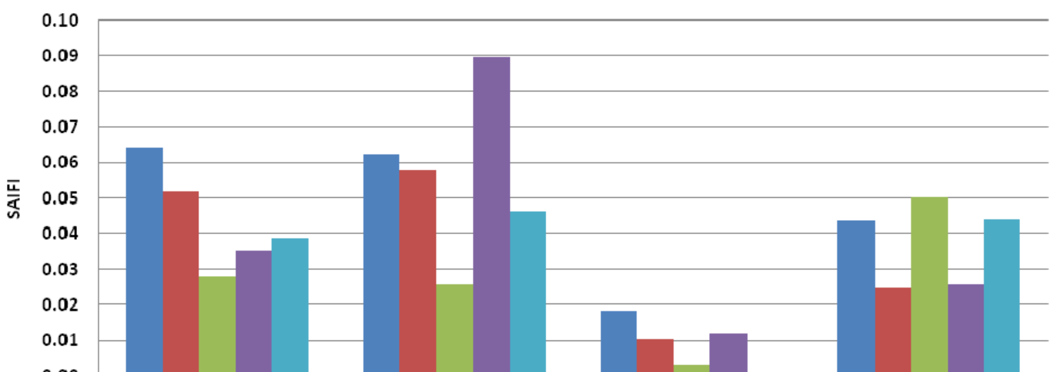


Figure 13: Weather Impacts to SAIDI

Weather impacts on the distribution system account for a significant portion of total system SAIFI and SAIDI. In 2013 weather related causes attributed 11% to the annual SAIFI and nearly 40% to the annual SAIDI. While volatile from year to year, the three cause codes combined provide a more accurate reflection of the impact of weather events on the system. Figures 12 and 13 above demonstrate that a large portion of the SAIFI and SAIDI improvements in 2012 can be attributed to favorable weather conditions, while part of the decline in 2013 relative to 2012 can be attributed to a return to more typically normal weather patterns.

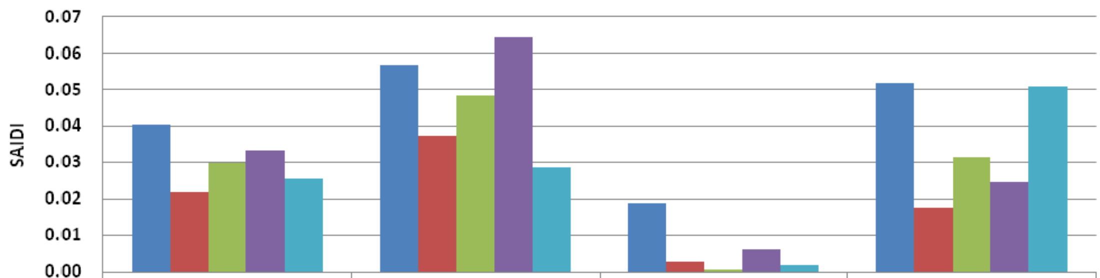
5.2. Foreign Interference Impacts

Foreign interference consists of outages caused by animal contact, dig-ins, vehicles, and other foreign objects. Though there are different ways to mitigate foreign interference, such as installing animal guards or moving assets to more secure locations, the yearly performance is generally more volatile to single events. Figures 14 and 15 below show the foreign interference impacts on Toronto Hydro's distribution system.



	Animals	Third Party Interference	Public	Vehicle
2009	0.06	0.06	0.02	0.04
2010	0.05	0.06	0.01	0.02
2011	0.03	0.03	0.00	0.05
2012	0.04	0.09	0.01	0.03
2013	0.04	0.05	0.00	0.04

Figure 14: Foreign Interference – Root Cause SAIFI



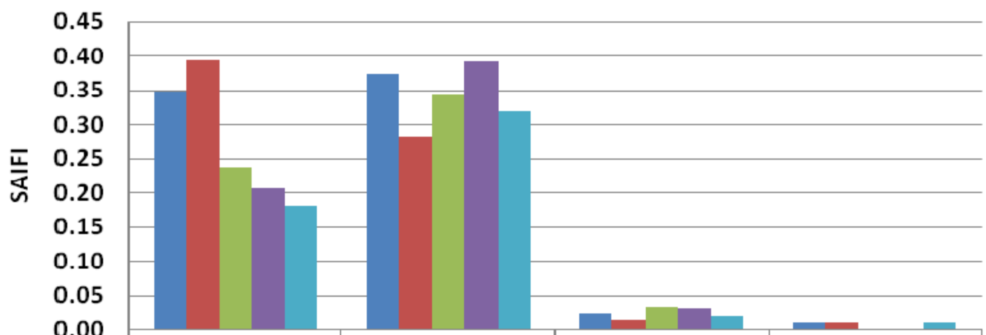
	Animals	Third Party Interference	Public	Vehicle
2009	0.04	0.06	0.02	0.05
2010	0.02	0.04	0.00	0.02
2011	0.03	0.05	0.00	0.03
2012	0.03	0.06	0.01	0.02
2013	0.03	0.03	0.00	0.05

Figure 15: Foreign Interference – Root Cause SAIDI

Of the four sub-categories, animal contact is one of the most “controllable”, in that Toronto Hydro is able to reasonably install measures to effectively militate against the risk. Toronto Hydro’s capital programs include animal guard replacement activities for this purpose (see the Overhead Circuit Renewal program, Exhibit 2B, Section E6.4, and the Worst Performing Feeder program, Exhibit 2B, Section E6.21), with new standard animal guards that eliminate a physical point of contact with live equipment and insulate all critical components. Since the start of animal guard replacement activities in 2010, animal contact has had a slight downward trend for both SAIFI and SAIDI. The remaining sub-categories are far more volatile and generally beyond Toronto Hydro’s direct control. For example, 13% of the foreign interference SAIDI for the year 2012 was attributed to a single incident, occurring on August 20th 2012, where a construction crane fell onto Toronto Hydro overhead lines. Similarly, on January 31st, 2012, contractors dug into Toronto Hydro’s underground cable causing repeated disruptions that added up to 12% of the foreign interference SAIFI for the year.

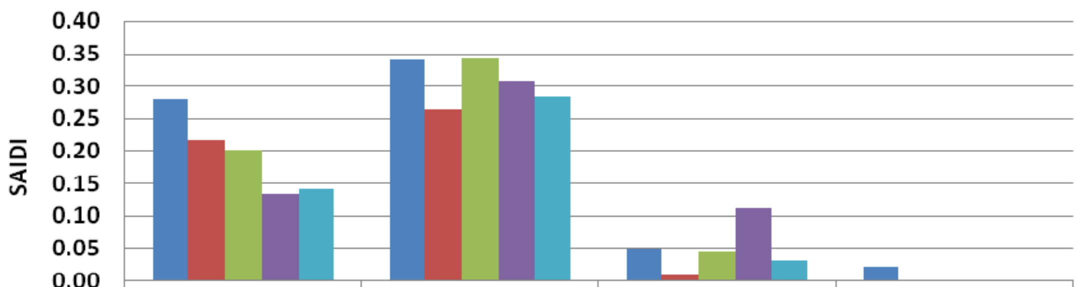
5.3. Defective Equipment Impacts

As shown in Figures 16 and 17, the contribution of defective equipment to Toronto Hydro's SAIFI and SAIDI has remained relatively stable, with the exception of the overhead system sub-cause code, which has seen a considerable reduction in outages.



	Overhead Equipment	Underground Equipment	Station Equipment	Others
2009	0.35	0.37	0.02	0.01
2010	0.39	0.28	0.01	0.01
2011	0.24	0.34	0.03	0.00
2012	0.21	0.39	0.03	0.00
2013	0.18	0.32	0.02	0.01

Figure 16: Defective Equipment SAIFI

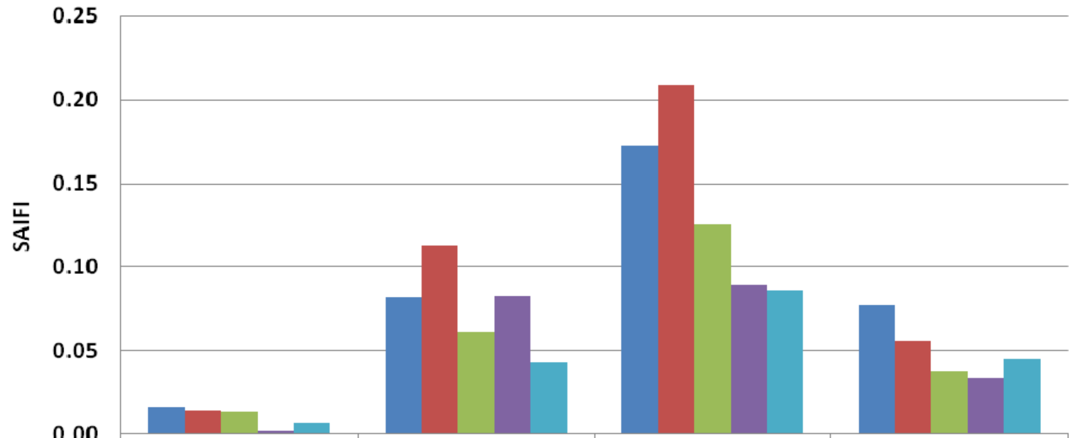


	Overhead Equipment	Underground Equipment	Station Equipment	Others
2009	0.28	0.34	0.05	0.02
2010	0.22	0.26	0.01	0.00
2011	0.20	0.34	0.04	0.00
2012	0.13	0.31	0.11	0.00
2013	0.14	0.28	0.03	0.00

Figure 17: Defective Equipment SAIDI

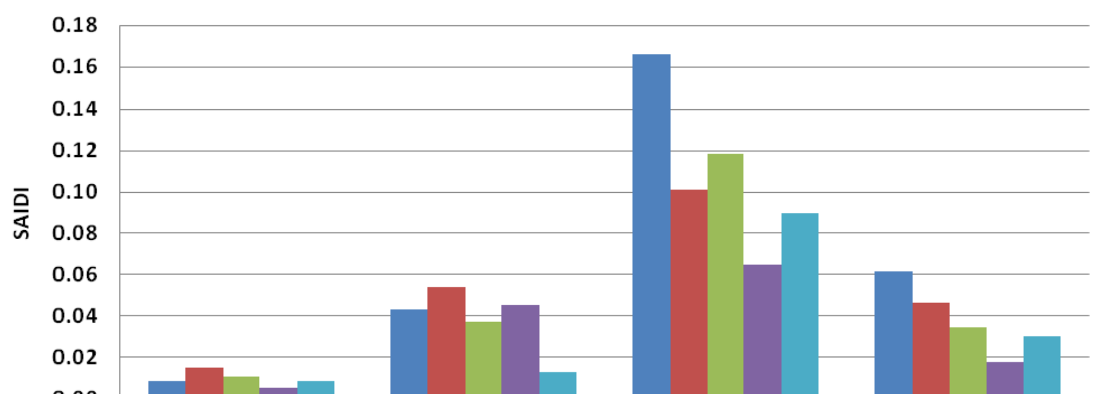
5.4. Overhead Defective Equipment

In the overhead sub-cause codes (Figures 18 and 19 below) the majority of the customer interruptions are caused by pole and pole hardware failures, as well as overhead switches. This is mainly due to the magnitude of these types of failures, which often disable large sections of feeders. Toronto Hydro has experienced an improvement in the SAIFI and SAIDI trend across all sub-categories, but particularly poles and pole hardware. This can be attributed to the extensive investment program that Toronto Hydro has been undertaking over the past years, with many overhead rebuilds and an aggressive porcelain insulator replacement program. Programs such as Rear Lot Conversion (see Exhibit 2B, E6.6) and Box Construction Conversion (see Exhibit 2B, E6.7) have also contributed to the improvement of the Overhead System. To maintain this result, Toronto Hydro plans to continue this effective replacement program throughout 2015-2019.



	Overhead Transformers	Overhead Switches	Poles and Pole Hardware	Others
2009	0.02	0.08	0.17	0.08
2010	0.01	0.11	0.21	0.06
2011	0.01	0.06	0.13	0.04
2012	0.00	0.08	0.09	0.03
2012	0.01	0.04	0.09	0.05

Figure 18: Defective Equipment SAIFI - Overhead

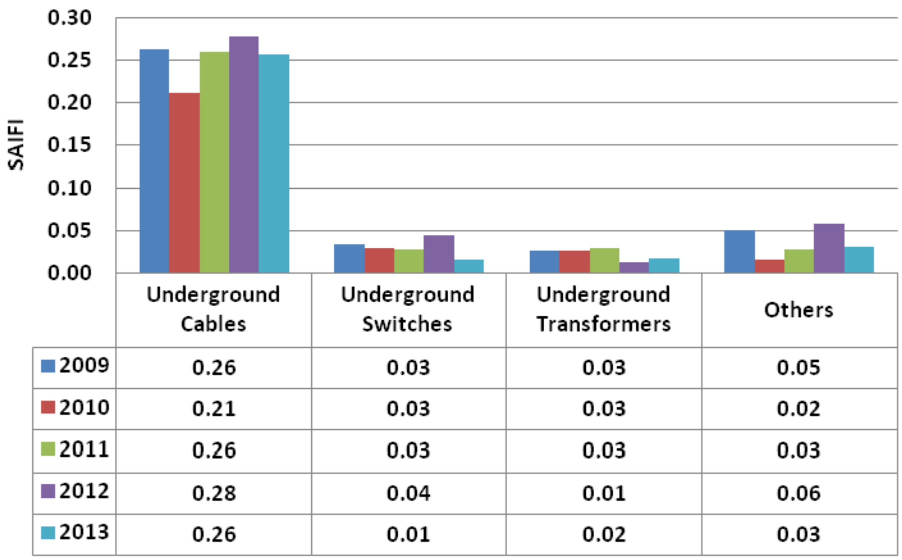


	Overhead Transformers	Overhead Switches	Poles and Pole Hardware	Others
2009	0.01	0.04	0.17	0.06
2010	0.02	0.05	0.10	0.05
2011	0.01	0.04	0.12	0.03
2012	0.01	0.05	0.06	0.02
2012	0.01	0.01	0.09	0.03

Figure 19: Defective Equipment SAIDI - Overhead

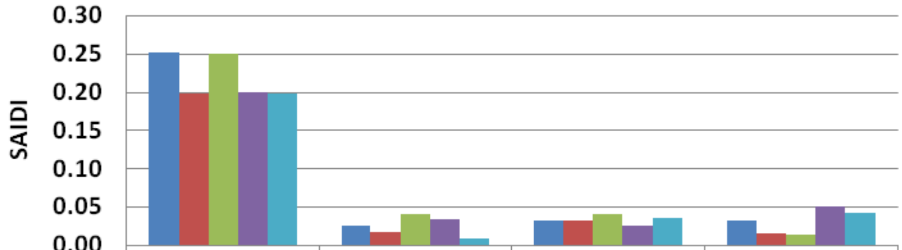
5.5. Underground Defective Equipment

In the underground sub cause code (Figures 20 and 21 below), underground cable faults dominate both the SAIFI and SAIDI indices and are the biggest equipment related cause of interruptions in Toronto Hydro's system. The majority of these failures are due to direct buried cables. Despite a heavy emphasis on the replacement of these cables over the past few years, the number of these assets reaching end of life or showing accelerated deterioration continues to increase. This trend supports the need to continue investment in replacing Direct Buried Cables, as detailed in Exhibit 2B, E6.1.



	Underground Cables	Underground Switches	Underground Transformers	Others
2009	0.26	0.03	0.03	0.05
2010	0.21	0.03	0.03	0.02
2011	0.26	0.03	0.03	0.03
2012	0.28	0.04	0.01	0.06
2013	0.26	0.01	0.02	0.03

Figure 20: Defective Equipment SAIFI - Underground



	Underground Cables	Underground Switches	Underground Transformers	Others
2009	0.25	0.02	0.03	0.03
2010	0.20	0.02	0.03	0.02
2011	0.25	0.04	0.04	0.01
2012	0.20	0.03	0.02	0.05
2013	0.20	0.01	0.03	0.04

Figure 21: Defective Equipment SAIDI - Underground

OEB Appendix 2-G
Service Reliability Indicators
2009 - 2013

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2009	2010	2011	2012	2013	2009	2010	2011	2012	2013
SAIDI	2.900	1.660	1.430	1.500	21.190	2.760	1.190	1.380	1.450	17.810
SAIFI	1.860	1.950	1.620	1.600	2.910	1.710	1.540	1.480	1.470	2.390

5 Year Historical Average

	Includes outages caused by loss of supply	Excludes outages caused by loss of supply
SAIDI	5.736	4.918
SAIFI	1.988	1.718

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2009	2010	2011	2012	2013	
Low Voltage Connections	90.0%	96.6%	96.2%	94.0%	92.5%	94.2%	
High Voltage Connections	90.0%	99.0%	99.2%	98.6%	99.3%	100.0%	
Telephone Accessibility	65.0%	83.7%	69.9%	72.7%	76.9%	82.0%	
Appointments Met	90.0%	99.7%	99.9%	99.6%	99.3%	99.6%	
Written Response to Enquires	80.0%	99.3%	97.5%	91.4%	86.5%	98.9%	
Emergency Urban Response	80.0%	79.5%	83.0%	83.4%	72.5%	74.4%	
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a	
Telephone Call Abandon Rate	10.0%	0.9%	2.5%	2.4%	1.7%	1.2%	
Appointment Scheduling	90.0%	96.5%	95.6%	97.6%	97.3%	96.6%	
Rescheduling a Missed Appointment	100.0%	98.8%	100.0%	100.0%	98.9%	98.4%	/C
Reconnection Performance Standard	85.0%	N/A	N/A	N/A	99.8%	100.0%	
Micro-Embedded Generation Facilities	90.0%	N/A	N/A	N/A	N/A	100.0%	