

SCHOOL ENERGY COALITION

**CROSS-EXAMINATION
MATERIALS**

IFRS ISSUES

EB-2011-0054

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Accounting for Specific Items

Property, Plant and Equipment

Contributions in aid of construction received in the form of services or property should be recorded in the capital asset accounts with an equal and offsetting entry to contra asset account 1995, Contributions and Grants-Credit.

Account 1995, Contributions and Grants - Credit should be amortized by debiting an accumulated amortization account and crediting an amortization expense account. This accounting entry will offset the amortization expense and accumulated amortization of the related property, plant and equipment accounts effectively eliminating amortization expense related to the portion of property, plant and equipment cost funded through contributions in aid of construction from the determination of the electric utility's revenue requirement.

A discussion of the recommended treatment of contributions in aid of construction using asset contra account 1995, Contributions and Grants-Credit and the resulting change in accounting policy, is discussed in Article 510—Transitional Issues Relating to Setting Up Accounts Pursuant to the *Electricity Act, 1998*.

Article 430—Development Charges and Contributions in Aid of Construction provide a complete discussion of the accounting treatment for Contributions in Aid of Construction.

b. Construction in Progress and Related Carrying Costs

General Summary

This subsection describes the recommended accounting treatment for construction in progress and related carrying costs, including interest on construction costs.

At year end, any property, plant and equipment under construction and related carrying costs, including interest, shall be included in "Construction in Progress". When the asset is put into service or when construction is substantially complete, the related items in Construction in Progress should be transferred to the appropriate property, plant and equipment account and amortization shall be calculated from that date.

Accounting Issues

Capitalization of Construction Costs

For the complete CICA Handbook discussion on construction in progress and related interest costs, refer to CICA Handbook paragraphs 3061.05, 20, 23-25.

Accounting for Specific Items

Property, Plant and Equipment

The cost of a capital asset includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity (CICA s.3061.20).

Additional guidance is found in Article 230, Definitions and Instructions, No. 20. Components of construction cost are to include where applicable, the cost of labour; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machinery services; allowance for funds used during construction; and such portion of overhead related costs as may be properly included in construction costs. Note that the capitalization policies for overhead related costs shall be approved by the Board.

Capitalization of Carrying Costs Including Interest Costs

In regard to the measurement of the carrying costs of a capital asset under construction and the capitalization of interest costs, the CICA Handbook notes that the cost of a capital asset that is acquired, constructed, or developed over time includes carrying costs directly attributable to the acquisition, construction, or development activity. For a rate-regulated capital asset, the cost includes the directly attributable allowance for funds used during construction ("AFUDC") allowed by the regulator (CICA s.3061.23).

Consistent with the CICA Handbook, electric utilities will be allowed to include the cost to the utility for funds used for the purposes of construction. The AFUDC rate should be based on a reasonable allowance for the use of funds expended during the construction period, whether or not such funds have been borrowed for the purposes of the capital project. The appropriateness of the AFUDC rate used by the electric utility will be subsequently reviewed by the Board and will be approved based on the Board's assessment of the reasonableness of the allowance.

As an interim measure, for the first generation IRM period, the Board viewed the debt cost rate (DCR) established in the Rate Handbook as a reasonable rate to be used as the maximum allowable limit for the AFUDC. For this period, a utility should use Table 3-1 of the Rate Handbook to determine the applicable DCR based on its deemed capital structure. As noted in Article 480, the Board may revisit the appropriateness of the DCR for purposes of the AFUDC rate for the period after the first generation IRM.

Article 480 provides details on the treatment of AFUDC related to qualifying transition costs and assets for market opening under "Construction Work in Progress".

Upon subsequent review of the AFUDC and consultation with stakeholders in 2006, the Board adopted an interest methodology for AFUDC based on the Scotia Capital Inc. All Corporates Mid-Term Average Weighted Yield, as published on the Bank of Canada's

Accounting for Specific Items

Property, Plant and Equipment

website. This prescribed rate of interest for AFUDC is effective from May 1, 2006 and is published each quarter on the Board's website (see CWIP account in webpage link: http://www.oeb.gov.on.ca/html/en/industryrelations/rulesguidesandforms_regulatory_prescribedinterestrates.htm.)

The following accounts have been provided for in the USoA for the purpose of recording the expense associated with borrowed or other funds used during construction:

- account 6040, Allowance For Borrowed Funds Used During Construction–Credit. This account shall include credits for Allowance for borrowed Funds Used During Construction ("AFUDC") that has been capitalized during the fiscal year. The debit shall be to account 2055, Construction Work in Progress - Electric. The AFUDC rate shall be based on a reasonable allowance for the use of funds expended during the construction period and shall be approved by the Board.
- account 6042, Allowance For Other Funds Used During Construction–Credit. This account shall include credits for allowance for other than borrowed funds used during construction. The credit shall be to account 2055, Construction Work in Progress - Electric. The rate of return shall be based on a reasonable allowance for the use of funds expended during the construction period and shall be approved by the Board. The AFUDC rate shall be based on a reasonable allowance for the use of funds expended during the construction period, whether or not such funds have been borrowed, and shall be approved by the Board.

Ceasing the Capitalization of Carrying Costs

The CICA Handbook specifies that capitalization of carrying costs should cease when a capital asset is substantially complete and ready for productive use. Determining when a capital asset, or a portion thereof, is substantially complete and ready for productive use requires consideration of the industry circumstances. Normally it would be predetermined by management with reference to such factors as productive capacity, occupancy level, or the passage of time (CICA s.3061.23). The Board will review management's policies in this regard.

Inclusion of Net Revenue or Expense in Cost

The CICA Handbook recommends that net revenue or expense derived from the employment or use of a capital asset prior to substantial completion and readiness for use be included in the cost of the capital asset (CICA s.3061.25).

Accounting for Specific Items**Property, Plant and Equipment**

Disclosure of Capitalized Interest

Disclosure considerations for capitalized interest are discussed in CICA Handbook Section 3850—Interest Capitalized, Disclosure Considerations.

Based on the CICA Handbook, electric utilities that have an accounting policy of capitalizing interest should disclose this policy as well as the amount of interest capitalized unless the interest capitalized is part of an allowance for funds used during construction, in which case such enterprises should disclose AFUDC in the period (CICA s. 3850.01-2).

c. Amortization Methods**General Summary**

This subsection describes acceptable amortization methods and revisions to the amortization method and estimated useful life for property, plant and equipment.

The APHandbook does not provide prescriptive guidance for the amortization of property, plant and equipment but allows professional judgment to be used in choosing the method that allows amortization to be recognized in a rational and systematic manner appropriate to the nature of the property, plant and equipment. Note that the Board may review the selected amortization methods, estimated useful lives and amortization rates, as it considers necessary.

Accounting Issues**Amortization Methods**

The CICA Handbook states that amortization should be recognized in a rational and systematic manner appropriate to the nature of property, plant and equipment (with a limited life) and to its use by the enterprise. The amount of amortization that should be charged to income is the greater of:

- a) the cost less salvage value over the life of the asset; and
- b) the cost less residual value over the useful life of the asset (CICA s.3061.28).

The CICA Handbook recognizes that different methods of amortizing a capital asset result in different patterns of charges to income. A straight-line method reflects a constant charge for the service as a function of time. A variable charge method reflects

Accounting for Specific Items

Property, Plant and Equipment

service as a function of usage. Other methods may be appropriate in certain situations. For example, an increasing charge method may be used when an enterprise can price its goods or services so as to obtain a constant rate of return on the investment in the capital asset. As another example, a decreasing charge method may be appropriate when the operating efficiency of the capital asset declines over time (CICA s.3061.31).

Note that the CICA Handbook states that factors to be considered in estimating the life and useful life of a capital asset include expected future usage, effects of technological or commercial obsolescence, expected wear and tear from use or the passage of time, the maintenance program, results of studies made regarding the industry, studies of similar items retired, and the condition of existing comparable terms (CICA s.3061.32).

In summary, the CICA Handbook does not provide prescriptive guidance for the amortization of property, plant and equipment but allows professional judgment to be used in choosing the method that allows amortization to be recognized in a rational and systematic manner appropriate to the nature of the capital asset (i.e. based on its use by the enterprise and its estimated useful life).

In contrast, the former Accounting for Municipal Electric Utilities in Ontario manual (section 5102—Fixed Assets Depreciation Rates for General Plant Assets and section 5103—Fixed Assets Depreciation Rates for Other Capital Assets) provided set schedules of asset types, estimated useful life, and depreciation rates based on the straight line method of depreciation.

Appendix E, “Capital Asset – Amortization Rates” of the Electricity Distribution Rate Handbook provides rates based on the straight line method of amortization. Electric utilities that were subject to reporting using the Accounting for Municipal Electric Utilities in Ontario manual as prescribed by the former Ontario Hydro will be expected to use these rates until a change can be supported by an objective study and the change has been authorized by the Board.

Consistent with the CICA Handbook, this APHandbook does not provide prescriptive guidance in terms of the amortization methods to be used, the asset categories, the estimated useful lives or amortization rates. Instead, it is expected that in the absence of an objective study to support changes to the current methods, lives or rates, utilities will continue to use methods, lives or rates consistent with past practice. Note that the Board may review the selected amortization methods, estimated useful lives and amortization rates, as it considers necessary.

Accounting for Specific Items**Property, Plant and Equipment**

Revision of Amortization Method/Estimated Useful Life

The CICA Handbook recommends that the amortization method and estimates of the life and useful life of a capital asset be reviewed on a regular basis (CICA s.3061.33).

Furthermore, there may be a need to revise the amortization method or estimates of the life and useful life of a capital asset due to the following significant events:

- a) a change in the extent the property, plant and equipment is used; or
 - b) a change in the manner in which the property, plant and equipment is used; or
 - c) removal of the property, plant and equipment from service for an extended period of time; or
 - d) physical damage; or
 - e) significant technological developments; or
 - f) a change in the law, environment, or consumer styles and tastes affecting the period of time over which the property, plant and equipment can be used.
- (CICA s.3061.34)

As an example specific to electric utilities, when property, plant and equipment previously classified as experimental electric plant is placed into service and reclassified as electric plant in service, a significant change has occurred in the manner in which the capital asset is used. Accordingly, the amortization method and estimated useful life of property, plant and equipment should be reviewed and revised accordingly in order to comply with GAAP.

Note that in accordance with the CICA Handbook, such a change would be treated as a change in accounting estimate because the change in the method of amortization in this example results from changed circumstances, experience or new information (CICA s.1506.05(b)). The effect of a change in an accounting estimate should be recognized prospectively by including it in net income in:

- a) the period of change, if the change affects that period only; or
 - b) the period of change and future periods, if the change affects both.
- (CICA s.1506.36)

See Article 320 for a discussion of changes in estimate.

6. Treatment of asset impairment

There was general agreement with the staff proposal related to asset impairment, which read as follows:

Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates.

The Board accepts this proposal.

Depreciation

Issue 4.1: Should the Board set parameters for depreciation accounting for regulatory purposes (E.g., depreciation methods, the level at which sub-componentization should be applied to specified asset classes)?

Issue 4.2: Should the Board set the parameters for electricity distributors to establish their own depreciation rates rather than continue to use depreciation rates historically approved by the Board (co-ordination of depreciation studies may be possible)?

Because IFRS does not currently recognize industry-specific accounting applicable to regulated enterprises, utilities in Ontario that have relied upon the Board to establish certain aspects of depreciation accounting will now be required to apply the accounting requirements of IFRS for financial reporting. Under IFRS, a review of useful life, depreciation methods and residual values is required to be conducted annually. Many of the municipally-owned electric utilities in Ontario have not conducted depreciation studies or reviewed the useful lives of their assets in many years, and rely on depreciation rates and methods that pre-date regulation of those utilities by the Board.

Board staff proposed that utilities continue to use the straight line method of depreciation for regulatory accounting purposes, and this was supported by participants.

4.1 Utilities should continue to use the straight line method of depreciation.

The Board agrees with this proposal.

However, staff did not propose that the Board set parameters for depreciation accounting for regulatory purposes, and issues such as the level of componentization required under IFRS remained unresolved during the consultation.

Under issue 4.2, staff proposed a depreciation study that would address such issues. The proposal read:

4.2 The Board will facilitate a joint depreciation study for electrical distribution utilities. The aim of the study will be to determine depreciation methodologies and rates that will be applied to all electrical distribution utilities for the purpose of setting rates and regulatory reporting. The study must give due weight to the IFRS requirements regarding depreciation, including componentization. Until the study is completed and the resulting depreciation rates are modified or adopted by the Board, electrical utilities will continue to use their present depreciation rates.

Any electrical utility retains the option of demonstrating, through a well-founded depreciation study, that the Board should approve specific depreciation methodologies and rates for that utility.

Gas utilities may submit a utility-specific depreciation study, which should include their proposed treatment of items unique to the gas industry (e.g., cushion gas).

Several participants pointed out that the results of a joint depreciation study would likely be useful but insufficient to satisfy the requirements under IFRS for individual consideration of depreciation rates by each utility. Utility specific work would still have to be done. Further, unless the study was repeated annually, the annual review requirement under IFRS would not be satisfied. The common view seemed to be that while such a study would be useful in establishing a common starting point for utilities and increasing consistency in depreciation rates for regulatory purposes, it would not completely solve the problem utilities face with IFRS compliance for financial reporting purposes.

While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the service lives for their particular assets for financial reporting and regulatory requirements.

The Board will undertake a depreciation study for electricity distributors. Until the study is completed and the resulting asset service lives are modified or adopted by the Board, electricity distributors may continue to use their present service lives for rate setting purposes. Some electricity distributors may choose to undertake a distributor-specific depreciation study or to participate in a study undertaken by a group of distributors rather than await the outcome of the Board study, and produce the results in their rate applications.

The Board agrees with the proposal that gas distributors continue to provide distributor-specific depreciation studies.

**Ontario Energy
Board**
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

**Commission de l'énergie
de l'Ontario**
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273



BY E-MAIL AND WEB POSTING

July 8, 2010

All Licensed Electricity Distributors

Re: Depreciation Study for Use by Electricity Distributors, Consultant Final Report EB-2010-0178 – Transition to International Financial Reporting Standards

As stated in its Report on Transition to International Financial Reporting Standards (IFRS) of July 2009 ("Board Report") (EB-2008-0408), the Board has commissioned a depreciation study to assist electricity distributors in Ontario in their transition to IFRS. The study was undertaken by Kinectrics Inc. and their report is posted on the [Board's website](#) ("Kinectrics Report").

The Board Report said the following concerning the usefulness of a generic depreciation study for distributors and concerning how it would be used.

"While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the service lives for their particular assets for financial reporting and regulatory requirements."

Accordingly, effective on transition to IFRS, the Board will no longer prescribe service lives for Property, Plant and Equipment recorded in the accounts of the distributors. So as not to depend on a rate-ruling from the regulator to define the service life (rate rulings have no status under IFRS standards as currently written), distributors are to have identified asset service lives that meet the International Accounting Standards Board (IASB) requirements. These requirements are stated in International Accounting Standard 16 (IAS 16), *Property, Plant and Equipment*, in particular in paragraphs 50, 51, 56 and 57 which are reproduced for convenience in Schedule A to this letter. The OEB in its Report of July 2009 adopted these IFRS accounting standards.

The Board's objective in providing the Kinectrics Report is to assist the distributors in their transition from Canadian Generally Accepted Accounting Principles applicable in a regulatory environment to these international standards.

The Kinectrics Report provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances. The Board expects distributors to reflect their consideration of the information contained in the Kinectrics Report when they present an IFRS-based rates application to the Board.

Given that the Kinectrics Report was prepared to support transition to IFRS and in recognition of the responsibility of distributors under IFRS to identify asset service lives, the Board does not intend to commission further work in this area. When appearing before the Board in future cost of service proceedings after the initial IFRS cost of service proceeding, distributors will be expected to provide update information to the Board regarding the useful lives of their assets along with justification for any changes.

Distributors are reminded that, as set out in the Board Report of July 2009, they are expected to identify the combined impacts arising from all the areas associated with the transition to IFRS when they apply to the Board in the first cost of service application after adopting IFRS. The Board Report also states the expectation that distributors will demonstrate that they have taken appropriate management action to mitigate any adverse impacts.

Questions regarding the use of the Kinectrics Report can be directed to: Bill Cowan, Senior Manager, Special Projects, Applications and Regulatory Audit at (416) 440-7648, bill.cowan@oeb.gov.on.ca or to the Board's Market Operations hotline at market.operations@oeb.gov.on.ca.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

c. Participants in EB-2008-0408

Schedule A

Excerpt from *International Accounting Standard # 16* Property, Plant and Equipment

50. The depreciable amount of an asset shall be allocated on a systematic basis over its useful life.
51. The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with *IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors*.
-
56. The future economic benefits embodied in an asset are consumed by an entity principally through its use. However, other factors, such as technical or commercial obsolescence and wear and tear while an asset remains idle, often result in the diminution of the economic benefits that might have been obtained from the asset. Consequently, all the following factors are considered in determining the useful life of an asset:
- a) Expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output.
 - b) Expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance programme, and the care and maintenance of the asset while idle.
 - c) Technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset.
 - d) Legal or similar limits on the use of the asset, such as the expiry dates of related leases.
57. The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Therefore, the useful life of an asset may be shorter than its economic life. The estimation of the useful life of the asset is a matter of judgment based on the experience of the entity with similar assets.

F SUMMARY OF RESULTS

Table F - 1 summarizes useful lives, and factors impacting those lives as developed by this report.

Table F - 1 Summary of Componentized Assets, Service Life and Factors

PARENT*	#	ASSET DETAILS			USEFUL LIFE			FACTORS **						
		Category Component Type			MIN UL	TUL	MAX UL	MC	EL	EN	OP	MP	NPF	
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	H	L	M	NI	L	L	
			Cross Arm	Wood	20	40	55							
				Steel	30	70	95							
	2	Fully Dressed Concrete Poles	Overall		50	60	80	H	L	M	NI	L	NI	
			Cross Arm	Wood	20	40	55							
				Steel	30	70	95							
	3	Fully Dressed Steel Poles	Overall		60	60	80	H	M	L	NI	L	NI	
			Cross Arm	Wood	20	40	55							
				Steel	30	70	95							
	4	OH Line Switch				30	45	55	L	L	L	L	M	L
	5	OH Line Switch Motor				15	25	25	L	NI	L	L	M	L
	6	OH Line Switch RTU				15	20	20	NI	NI	L	L	L	M
7	OH Integral Switches				35	45	60	L	M	M	M	L	H	
8	OH Conductors				50	60	75	M	L	M	NI	NI	L	
9	OH Transformers & Voltage Regulators				30	40	60	L	M	M	NI	NI	M	
10	OH Shunt Capacitor Banks				25	30	40	-	-	-	-	-	-	
11	Reclosers				25	40	55	L	L	L	M	L	M	
TS & MS	12	Power Transformers	Overall		30	45	60	NI	M	M	L	L	NI	
			Bushing		10	20	30							
			Tap Changer		20	30	60							
	13	Station Service Transformer				30	45	55	NI	L	M	L	NI	L
	14	Station Grounding Transformer				30	40	40	-	-	-	-	-	-
	15	Station DC System	Overall		10	20	30	NI	M	L	L	M	M	
			Battery bank		10	15	15							
			Charger		20	20	30							
	16	Station Metal Clad Switchgear	Overall		30	40	60	L	L	M	M	M	M	
			Removable Breaker		25	40	60							
17	Station Independent Breakers				35	45	65	M	M	M	M	M	M	
18	Station Switch				30	50	60	M	L	M	M	M	L	
* OH = Overhead Lines System TS & MS = Transformer and Municipal Stations														
** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions														
MP = Maintenance Practices NPF=Non-Physical Factors														
H=High M=Medium L=Low NI=No Impact														

PARENT*	#	ASSET DETAILS		USEFUL LIFE			FACTORS **					
		Category Component Type		MIN UL	TUL	MAX UL	MC	EL	EN	OP	MP	NPF
TS & MS	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H
	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H
	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H
	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L
	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	M	M	M	L	L	L
	27	Primary Non-TR XLPE Cables In Duct		20	25	30	M	M	M	L	L	M
	28	Primary TR XLPE Cables Direct Buried		25	30	35	M	M	M	L	L	L
	29	Primary TR XLPE Cables In Duct		35	40	55	M	M	M	L	L	L
	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H
	31	Secondary Cables Direct Buried		25	35	40	M	M	M	L	NI	NI
	32	Secondary Cables In Duct		35	40	60	M	M	M	L	NI	NI
	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI
			Protector	20	35	40						
	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L
	35	Submersible/Vault Transformers		25	35	45	L	M	M	NI	L	L
	36	UG Foundations		35	55	70	M	NI	M	L	L	M
	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L
			Roof	20	30	45						
	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI
	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L
	40	Ducts		30	50	85	H	NI	M	NI	NI	L
	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L
42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI	
S	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H
* TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems ** MC = Mechanical Stress EL = Electrical Loading OP = Operating Practices EN = Environmental Conditions MP = Maintenance Practices NPF=Non-Physical Factors H=High M=Medium L=Low NI=No Impact												

Table F - 2 summarizes useful life ranges for Ontario's Local Distribution Companies' non-distribution assets. Table F - 2 contains assets that were not studied in detail in this analysis and represent recommended ranges based on the experience of Ontario LDCs interviewed. A further analysis of these assets is not considered necessary.

Table F - 2 Summary Useful Life of Minor Assets

#	ASSET DETAILS		USEFUL LIFE RANGE
	Category - Component - Type		
1	Office Equipment		5-15
2	Vehicles	Trucks & Buckets	5-15
		Trailers	5-20
		Vans/Cars	5-10
3	Administrative Buildings		50-75
4	Leasehold Improvements		Lease dependent
5	Station Buildings	Station Building	50-75
		Parking	25-30
		Fence	25-60
		Roof	20-30
6	Computer Equipment	Hardware	3-5
		Software	2-5
7	Equipment	Power Operated	5-10
		Stores	5-10
		Tools, Shop, Garage Equipment	5-10
		Measurement & Testing Equipment	5-10
8	Communication	Towers	60-70
		Wireless	2-10
9	Residential Energy Meters		25-35
10	Industrial/Commercial Energy Meters		25-35
11	Wholesale Energy Meters		15-30
12	Current & Potential Transformer (CT & PT)		35-50
13	Smart Meters		5-15
14	Repeaters - Smart Metering		10-15
15	Data Collectors - Smart Metering		15-20



DEPRECIATION/AMORTIZATION/DISPOSAL SCHEDULE

Hydro Ottawa Limited ("Hydro Ottawa") is not proposing to make any changes from the amortization rates that were used in the 2008 Electricity Distribution Rate Application (EB-2007-0713). As per the Capitalization Policy (Attachment Q to Exhibit B1-3-1) this means following the method and lives set out by the Ontario Energy Board (the "Board"). Therefore an amortization study is not included with this application.

Hydro Ottawa uses the half year rule for calculating depreciation/amortization in the year that capital additions are added to the rate base for both actual and budgeted pooled assets, except in the case of discrete material assets, such as a station. In those specific cases, that actual or forecasted in-service month would be used to calculate the depreciation/amortization.

The following tables detail the amortization expenses for 2008 Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Budget and 2012 Budget, by asset group. Also included is the amortization period for the various assets that make up each grouping. As detailed in Exhibit I2-1-1, Hydro Ottawa received approval to recover the cost of meters stranded as a result of the installation of Smart Meters over a six year period. \$2,987k has been included in the amortization expense for 2012, which is the fifth year of the six year period.

Also included in the Tables is the affect on amortization from actual disposals in 2008, 2009 and 2010 and budgeted disposals in 2011 and 2012.

Hydro Ottawa has not provided Appendix 2-M of the Board's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued on June 28, 2010, as it is a simplified approach to the calculation of depreciation expense and the depreciation expense is already provided in Exhibit B2-1-1, Attachment S (Updated).



Table 1 – Approved/Actual Amortization Expense 2008 to 2009

Asset Group	2008 Approved Amortization Expense \$000	2008 Actual Amortization Expense \$000	2008 Actual Disposals \$000	2009 Actual Amortization Expense \$000	2009 Actual Disposals \$000	Amortization Period (years)
Land and Buildings	(77)	(759)	1	1,798	4	Note 1
TS Primary Above 50	(1,049)	(874)	0	(1,330)	0	40
DS	(1,148)	(1,102)	2	(1,870)	427	30
Poles, Wires	(14,766)	(14,692)	0	(15,129)	36,124	25
Line Transformers	(4,042)	(3,926)	0	(3,902)	28,006	25
Services and Meters	(6,720)	(7,365)	(219)	(7,903)		Note 2
General Plant	(1,089)	(359)	0	(2,999)		Note 3
Equipment	(2,912)	(2,947)	9,947	(3,152)	1,066	10
IT Assets	(8,237)	(8,892)	16,455	(8,734)	(436)	Note 4
Other Distribution Assets	(782)	(661)	94	(677)	3,966	Note 5
TOTAL	(\$40,822)	(\$41,576)	\$26,279	(\$43,898)	\$69,157	

Notes:

1. Land is not amortized; Land Rights and Buildings are amortized over 50 years.
2. Services and conventional meters are amortized over 25 years; Smart Meters over 15 years.
3. Buildings & Fixtures – Brick, Concrete and Steel is amortized over 50 years; Other construction over 25 years.
4. Computer hardware and some software are amortized over 5 years; the CIS is amortized over 10 years.
5. Load Management Controls are amortized over 10 years; System Supervisory Equipment over 15 years.



Table 2 – Actual/Budget Amortization Expense 2009 to 2012

Asset Group	2009 Adjustment \$000 ¹	2010 Actual Amortization Expense \$000	2010 Actual Disposals \$000	2011 Budget Amortization Expense \$000	2011 Budgeted Disposals \$000	2012 Budget Amortization Expense \$000	2012 Budgeted Disposals \$000	Amortization Period (years)
Land and Buildings	2	(392)		(429)	0	(508)		Note 1
TS Primary Above 50		(1,364)		(1,797)	0	(1,973)		Note 2
DS		(1,735)	100	(1,951)	0	(2,393)		30
Poles, Wires		(15,814)	2,119	(15,946)	0	(16,200)		25
Line Transformers		(3,726)	22,086	(3,378)	0	(3,459)		25
Services and Meters		(8,887)	0	(9,106)	0	(9,554)		Note 3
General Plant	989	(908)		(914)	0	(960)		Note 4
Equipment		(3,135)	1,650	(3,229)	1,076	(3,206)	1,174	Note 5
IT Assets		(9,531)	686	(9,244)	0	(8,197)		Note 6
Other Distribution Assets		(736)	49	(834)	0	(966)		Note 7
TOTAL	\$991	(\$46,229)	\$26,689	(\$46,828)	\$1,076	(\$47,415)	\$1,174	

Notes:

1. Land is not amortized; Land Rights and Buildings are amortized over 50 years.
2. Services and conventional meters are amortized over 25 years; Smart Meters over 15 years.
3. Buildings & Fixtures – Brick, Concrete and Steel is amortized over 50 years; Other construction over 25 years.
4. Computer hardware and some software are amortized over 5 years; the CIS is amortized over 10 years.
5. Load Management Controls are amortized over 10 years; System Supervisory Equipment over 15 years.

¹ 2009 Adjustment relates to the removal of Non Distribution Assets from rate base.
2012 Electricity Distribution Rate Application



Included in Table 2 above are the following Asset Retirement Obligations ("ARO"):

Asset Retirement Obligation	USoA	Gross ARO as of Dec. 31, 2009 \$	2010 Depreciation Expense \$	Net Book Value 2010 \$	2011 Depreciation Expense \$	Net Book Value 2011 \$	2012 Depreciation Expense \$	Net Book Value 2012 \$
Station Equipment (Below 50 kV)	1820	9,647	(2,410)	7,237	(2,410)	4,827	(2,417)	2,410
Line Transformers	1815	929,814	(232,294)	697,520	(232,924)	465,226	(232,931)	232,294
Total		\$939,461	(\$234,704)	\$704,757	(\$234,705)	\$470,052	(\$235,348)	\$234,704



Appendix 2-B
MIFRS January 1, 2011 Opening Balance - Fixed Asset Continuity Schedule

			Year	Opening Position								
CCA Class	OEB	Description	Cost \$000					Accumulated Depreciation \$000			MIFRS Net Book Value January 1, 2011	
			IFRS Depreciation Rate	CGAAP Opening Balance	Accumulated Depreciation Adjustment	Capital Contribution Adjustment	MIFRS Opening Balance	CGAAP Opening Balance	Accumulated Depreciation Adjustment	MIFRS Opening Balance		
N/A	1805	Land	N/A	\$4,446			\$4,446	\$0		\$0	\$4,446	
ECE	1806	Land Rights	50	2,716			2,716	(907)		(907)	1,809	
1.3	1808	Buildings and Fixtures	25 - 75	20,311			20,311	(3,790)		(3,790)	16,521	
47	1815	Station Equipment (Above 50 kV)	15 - 45	68,859			68,859	(11,928)		(11,928)	56,931	
47	1820	Station Equipment (Below 50 kV)	15 - 45	66,047			66,047	(29,676)		(29,676)	36,371	
47	1830	Poles, Towers and Fixtures	45	120,490			120,490	(59,899)		(59,899)	60,591	
47	1835	Overhead Conductors and Devices	25 - 45	68,543			68,543	(23,721)		(23,721)	44,823	
47	1840	Underground Conduit	40	172,845			172,845	(97,710)		(97,710)	75,135	
47	1845	Underground Conductors and Devices	25 - 60	159,017			159,017	(73,065)		(73,065)	85,952	
47	1850	Line Transformers	30 - 35	111,976			111,976	(44,741)		(44,741)	67,236	
47	1850	Line Transformers in Inventory	N/A	3,976			3,976	(977)		(977)	2,999	
47	1855	Services	45	101,606			101,606	(30,927)		(30,927)	70,679	
47	1860	Meters	15 - 25	48,098			48,098	(35,763)		(35,763)	12,335	
47	1860	Smart Meters	15	52,489			52,489	(10,813)		(10,813)	41,676	
47	1860	Meters in Inventory	N/A	272			272	(131)		(131)	141	
N/A	1905	Land	N/A	863			863	0		0	863	
ECE	1906	Land Rights	50	132			132	(103)		(103)	28	
1.3	1908	Buildings and Fixtures	20 - 75	45,770			45,770	(10,109)		(10,109)	35,661	
1.3	1908	Buildings and Fixtures	25	2,860			2,860	(2,302)		(2,302)	557	
8	1915	Office Furniture and Equipment	10	3,996			3,996	(2,432)		(2,432)	1,565	
50	1920	Computer Equipment - Hardware	5 - 10	10,584			10,584	(7,197)		(7,197)	3,386	
12	1925	Computer Software	5	38,307			38,307	(26,588)		(26,588)	11,720	
12	1925	Computer Software 10 Yrs	10	24,710			24,710	(15,317)		(15,317)	9,394	
10	1930	Automobiles	7	185			185	(182)		(182)	4	
10	1930	Trucks less than 3 tonnes	8	2,051			2,051	(1,780)		(1,780)	271	
10	1930	Trucks greater than 3 tonnes	12	16,924			16,924	(11,318)		(11,318)	5,606	
10	1930	Power Operated Equipment	15	1,706			1,706	(1,205)		(1,205)	501	
8	1935	Stores Equipment	10	217			217	(166)		(166)	51	
8	1940	Tools, Shop and Garage Equipment	10	6,787			6,787	(3,206)		(3,206)	3,581	
8	1945	Measurement and Testing Equipment	10	743			743	(596)		(596)	147	
8	1955	Communication Equipment	8	1,469			1,469	(903)		(903)	566	
8	1960	Miscellaneous Equipment	10	216			216	(39)		(39)	176	
8	1970	Load Mgmt Controls - Customer Premises	10	614			614	(265)		(265)	349	
8	1975	Load Mgmt Controls - Utility Premises	10	72			72	(32)		(32)	40	
8	1980	System Supervisory Equipment	15	11,332			11,332	(4,514)		(4,514)	6,818	
47	1995	Contributions and Grants - Credit		(176,017)			(176,017)	35,847		35,847	(140,171)	
		Total		\$995,214		\$0	\$0	\$995,214	(\$476,455)	\$0	(\$476,455)	\$518,758

Totals may not match due to rounding



Appendix 2-B MIFRS Fixed Asset Continuity Schedule

Year **2011**

			Cost \$000					Accumulated Depreciation \$000				
CCA Class	OEB	Description	IFRS Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	N/A	\$4,446	\$0		\$4,446	\$0	\$0		\$0	\$4,446
ECE	1806	Land Rights	50	\$2,716	0		2,716	(\$907)	(46)		(954)	1,762
1.3	1808	Buildings and Fixtures	25 - 75	\$20,311	2,127		22,438	(\$3,790)	(712)		(4,502)	17,936
47	1815	Station Equipment (Above 50 kV)	15 - 45	\$68,859	5,395		74,254	(\$11,928)	(2,308)		(14,237)	60,017
47	1820	Station Equipment (Below 50 kV)	15 - 45	\$66,047	16,412		82,459	(\$29,676)	(3,547)		(33,223)	49,236
47	1830	Poles, Towers and Fixtures	45	\$120,490	6,863		127,354	(\$59,899)	(1,572)		(61,471)	65,882
47	1835	Overhead Conductors and Devices	25 - 45	\$68,543	5,344		73,887	(\$23,721)	(1,286)		(25,006)	48,881
47	1840	Underground Conduit	40	\$172,845	7,443		180,289	(\$97,710)	(1,992)		(99,702)	80,586
47	1845	Underground Conductors and Devices	25 - 60	\$159,017	11,138		170,155	(\$73,065)	(3,442)		(76,507)	93,648
47	1850	Line Transformers	30 - 35	\$111,976	7,486		119,463	(\$44,741)	(2,132)		(46,873)	72,590
47	1850	Line Transformers in Inventory	N/A	\$3,976	0		3,976	(\$977)	0		(977)	2,999
47	1855	Services	45	\$101,606	7,749		109,355	(\$30,927)	(1,201)		(32,129)	77,227
47	1860	Meters	15 - 25	\$48,098	481	0	48,579	(\$35,763)	(2,956)	0	(38,719)	9,860
47	1860	Smart Meters	15	\$52,489	888		53,377	(\$10,813)	(3,662)		(14,476)	38,901
47	1860	Meters in Inventory	N/A	\$272	0		272	(\$131)	0		(131)	141
N/A	1905	Land	N/A	\$863	0		863	\$0	0		0	863
ECE	1906	Land Rights	50	\$132	0		132	(\$103)	(1)		(104)	28
1.3	1908	Buildings and Fixtures	20 - 75	\$45,770	1,230	(23)	46,977	(\$10,109)	(2,012)		(12,121)	34,856
1.3	1908	Buildings and Fixtures	25	\$2,860	0		2,860	(\$2,302)	(209)		(2,511)	349
8	1915	Office Furniture and Equipment	10	\$3,996	230		4,226	(\$2,432)	(378)		(2,809)	1,417
50	1920	Computer Equipment - Hardware	5 - 10	\$10,584	1,063		11,646	(\$7,197)	(1,745)		(8,942)	2,705
12	1925	Computer Software	5	\$38,307	4,510		42,818	(\$26,588)	(5,314)		(31,902)	10,916
12	1925	Computer Software 10 Yrs	10	\$24,710	0		24,710	(\$15,317)	(2,505)		(17,822)	6,889
10	1930	Automobiles	7	\$185	253		439	(\$182)	(19)		(201)	238
10	1930	Trucks less than 3 tonnes	8	\$2,051	96		2,148	(\$1,780)	(54)		(1,834)	313
10	1930	Trucks greater than 3 tonnes	12	\$16,924	1,610		18,534	(\$11,318)	(686)		(12,004)	6,531
10	1930	Power Operated Equipment	15	\$1,706	41		1,747	(\$1,205)	(43)		(1,248)	498
8	1935	Stores Equipment	10	\$217	0		217	(\$166)	(27)		(192)	25
8	1940	Tools, Shop and Garage Equipment	10	\$6,787	567		7,354	(\$3,206)	(734)		(3,940)	3,414
8	1945	Measurement and Testing Equipment	10	\$743	0		743	(\$596)	(66)		(661)	82
8	1955	Communication Equipment	8	\$1,469	797		2,266	(\$903)	(282)		(1,185)	1,080
8	1960	Miscellaneous Equipment	10	\$216	76		292	(\$39)	(27)		(66)	226
8	1970	Load Mgmt Controls - Customer Premises	10	\$614	441		1,055	(\$265)	(86)		(351)	704
8	1975	Load Mgmt Controls - Utility Premises	10	\$72	0		72	(\$32)	(8)		(40)	32
8	1980	System Supervisory Equipment	15	\$11,332	1,474		12,806	(\$4,514)	(813)		(5,327)	7,479
47	1995	Contributions and Grants - Credit		(\$176,017)	(15,409)		(191,427)	\$35,847	214		36,060	(155,366)
		Total		\$995,214	\$68,305	(\$23)	\$1,063,496	(\$476,455)	(\$39,650)	\$0	(\$516,105)	\$547,391

10	Transportation
8	Stores Equipment

Less: Fully Allocated Depreciation

Transportation	0
Stores Equipment	0
Net Depreciation	0

We agree to the CCA classes except Buildings have been placed in Class 1, Computer Equipment in Class 50 and Other Equipment in Class 8 as reflected in the current PILS model.
Totals may not match due to rounding

Appendix 2-B
MIFRS Fixed Asset Continuity Schedule

		Year		2012										
CCA Class	OEB	Description	Cost \$000					Accumulated Depreciation \$000						Net Book Value
			IFRS Depreciation Rate	Opening Balance	Adjustment	Additions	Disposals	Closing Balance	Opening Balance	Adjustment	Additions	Disposals	Closing Balance	
N/A	1805	Land	N/A	4,446		0		4,446	0		0		0	4,446
ECE	1806	Land Rights	50	2,716		0		2,716	(954)		(46)		(1,000)	1,716
1.3	1808	Buildings and Fixtures	25 - 75	22,438		5,461		27,899	(4,502)		(633)		(5,136)	22,763
47	1815	Station Equipment (Above 50 kV)	15 - 45	74,254		661		74,915	(14,237)		(2,282)		(16,519)	58,396
47	1820	Station Equipment (Below 50 kV)	15 - 45	82,459		10,433		92,892	(33,223)		(3,590)		(36,813)	56,080
47	1830	Poles, Towers and Fixtures	45	127,354		8,278		135,632	(61,471)		(1,740)		(63,212)	72,420
47	1835	Overhead Conductors and Devices	25 - 45	73,887		7,746		81,633	(25,006)		(1,449)		(26,456)	55,178
47	1840	Underground Conduit	40	180,289		6,883		187,172	(99,702)		(2,171)		(101,874)	85,298
47	1845	Underground Conductors and Devices	25 - 60	170,155		11,483		181,638	(76,507)		(3,708)		(80,215)	101,423
47	1850	Line Transformers	30 - 35	119,463		8,110		127,573	(46,873)		(2,390)		(49,263)	78,310
47	1850	Line Transformers in Inventory	N/A	3,976		0		3,976	(977)		0		(977)	2,999
47	1855	Services	45	109,355		8,636		117,991	(32,129)		(1,383)		(33,512)	84,479
47	1860	Meters	15 - 25	48,579	(53)	486		49,012	(38,719)		(3,014)		(41,733)	7,279
47	1860	Smart Meters	15	53,377	1,892	827		56,096	(14,476)	(61)	(3,842)		(18,379)	37,717
47	1860	Meters in Inventory	N/A	272		0		272	(131)		0		(131)	141
N/A	1905	Land	N/A	863		4,000		4,863	0		0		0	4,863
ECE	1906	Land Rights	50	132		0		132	(104)		(1)		(105)	27
1.3	1908	Buildings and Fixtures	20 - 75	46,977		713		47,690	(12,121)		(1,857)		(13,977)	33,713
1.3	1908	Buildings and Fixtures	25	2,860		0		2,860	(2,511)		(209)		(2,720)	140
8	1915	Office Furniture and Equipment	10	4,226		230		4,456	(2,809)		(317)		(3,127)	1,329
50	1920	Computer Equipment - Hardware	5 - 10	11,646	423	1,371		13,441	(8,942)	(42)	(1,252)		(10,236)	3,205
12	1925	Computer Software	5	42,818	1,403	4,372		48,593	(31,902)	(140)	(4,586)		(36,628)	11,965
12	1925	Computer Software 10 Yrs	10	24,710		0		24,710	(17,822)		(2,505)		(20,327)	4,384
10	1930	Automobiles	7	439		254		692	(201)		(55)		(256)	437
10	1930	Trucks less than 3 tonnes	8	2,148		456		2,604	(1,834)		(89)		(1,923)	681
10	1930	Trucks greater than 3 tonnes	12	18,534		1,592		20,127	(12,004)		(819)		(12,823)	7,304
10	1930	Power Operated Equipment	15	1,747		122		1,868	(1,248)		(48)		(1,296)	572
8	1935	Stores Equipment	10	217		0		217	(192)		(16)		(208)	9
8	1940	Tools, Shop and Garage Equipment	10	7,354		600		7,954	(3,940)		(726)		(4,666)	3,288
8	1945	Measurement and Testing Equipment	10	743		0		743	(661)		(36)		(697)	46
8	1955	Communication Equipment	8	2,266		92		2,357	(1,185)		(262)		(1,448)	910
8	1960	Miscellaneous Equipment	10	292		76		368	(66)		(34)		(100)	267
8	1970	Load Mgmt Controls - Customer Premises	10	1,055		0		1,055	(351)		(108)		(459)	596
8	1975	Load Mgmt Controls - Utility Premises	10	72		0		72	(40)		(6)		(48)	24
8	1980	System Supervisory Equipment	15	12,806		1,781		14,587	(5,327)		(890)		(6,216)	8,371
47	1995	Contributions and Grants - Credit		(191,427)		(17,198)		(208,625)	36,060		663		36,723	(171,902)
		Total		\$1,063,496	\$3,665	\$67,466	\$0	\$1,134,627	(\$516,105)	(\$244)	(\$39,405)	\$0	(\$555,754)	\$578,873

10	Transportation
8	Stores Equipment

Less: Fully Allocated Depreciation

Transportation	0
Stores Equipment	0
Net Depreciation	0

We agree to the CCA classes except Buildings have been placed in Class 1, Computer Equipment in Class 50 and Other Equipment in Class 8 as reflected in the current PILS model.

Totals may not match due to rounding



1

Table 3 – PP&E Components and Useful Lives

USofA Account Number	Description	OEB Useful life (years) ¹	IFRS Useful life (years)
1805	Land	NA	NA
1806	Land Rights	50	50
1808	Buildings and Fixtures	50	25 - 75
1815	Station Equipment (Above 50kV)	25 - 40	15 - 45
1820	Station Equipment (Below 50kV)	25 - 30	15 - 45
1830	Poles, Towers, Fixtures	25	45
1835	Overhead Conductors and Devices	25	25 - 45
1840	Underground Conduit	25	40
1845	Underground Conductors and Devices	25	25 - 60
1850	Line Transformers	25	30 - 35
1855	Services	25	45
1860	Meters	25	15 – 25
1860	Smart Meters	15	15
1905	Land	NA	NA
1906	Land Rights	50	50
1908	Buildings and Fixtures	50	20 - 75
1908	Buildings and Fixtures – Other	25	25
1915	Office Furniture & Equipment	10	10
1920	Computer Equipment – Hardware	5 – 10	5 – 10
1925	Computer Software	5	5
1925	Computer Software 10 Yrs	10	10
1930	Automobiles	4	7
1930	Trucks Less Than 3 tonnes	5	8
1930	Trucks Greater Than 3 tonnes	8	12
1930	Powered Equip & Trailers	8	15
1935	Stores Equipment	10	10
1940	Tools, Shop & Garage Equipment	10	10
1945	Measurement & Testing Equipment	10	10
1955	Communication Equipment	10	8
1960	Equipment - Miscellaneous	10	10
1970	Load Mgmt Contrls Cust Prem	10	10
1975	Load Mgmt Contrls Utility Prem	10	10
1980	System Supervisory Equipment	15	15

¹ OEB Useful life represents the former depreciation rate under CGAAP

Hydro Ottawa Limited
Components and Estimated Useful Lives

OEB Cost Code	Original JDE Cost Code		Original Asset Components	OEB Depreciation (years)		New JDE Cost Code		New Asset Components	IFRS Life (years)	Residual Value Estimate
Tangible Assets										
1805	1100	1	Lands - Distribution	NA		1100	1	Lands - Distribution System	NA	NA
1905	1101	2	Lands - General	NA		1110	2	Lands - General	NA	NA
1808	1700	3	Buildings & Fixtures Distribution - Brick, Concrete & Steel	50		1700	3	Bldg Sub Stn BC&S - Other	30	NA
				50		1710	4	Bldg Sub Stn BC&S - Structure	75	NA
1908	1701	4	Buildings & Fixtures General Brick, Concrete & Steel	50		1720	5	Bldg Gen BC&S - Fittings	30	NA
				50		1730	6	Bldg Gen BC&S - Structure	75	NA
				50		1740	7	Bldg Gen BC&S - Roof Covering	25	NA
				50		1750	8	Bldg Gen BC&S - Power Backup	25	NA
				50		1760	9	Bldg Gen BC&S - Parking Lot	20	NA
1808	1900	5	Buildings & Fixtures Brick - Distribution Other Construction	25		1900	10	Bldg & Fixtures - Distribution Other	25	NA
1908	1901	6	Buildings & Fixtures Brick - General Other Construction	25		1910	11	Bldg & Fixtures - General Other	25	NA
1915	2100	7	Office Furniture & Equipment	10		2100	12	Office Furniture & Equipment	10	NA
1920	2300	8	Computer Equipment	5		2300	13	Cmptr Equip General	5	NA
				5		2310	14	Cmptr Equip Notebook Computers	5	NA
				10		2320	15	Computer Equipment Major Initiatives	10	NA
1955	2700	9	Communication Equipment	10		2700	16	Communication Equipment	8	NA
1970	2900	10	Load Mgmt Controls Cust Prem	10		2900	17	Load Mgmt Contrls Cust Prem	10	NA
1975	3100	11	Load Mgmt Controls Utility Prem	10		3100	18	Load Mgmt Contrls Utility Prem	10	NA
1935	3300	12	Stores Equipment	10		3300	19	Stores Equipment	10	NA
1930	3700	13	Automobiles	4		3700	20	Automobiles	7	6%
	3900	14	Trucks less than 3 tonnes	5		3900	21	Trucks Less Than 3 tonnes	8	6%
	4100	15	Trucks greater than 3 tonnes	8		4100	22	Trucks Greater Than 3 tonnes	12	6%
	4300	16	Power Operated Equipment	8		4300	23	Powered Equip & Trailers	15	6%
2075	4700	17	Solar Power Generation	25		4700	24	Generation Equipment	25	
1940	4900	18	Tools, Shop & Garage Equipment	10		4900	25	Tools, Shop & Garage Equipment	10	NA
1960	5100	19	Misc. Equipment	10		5100	26	Equipment - Miscellaneous	10	NA
1860	5500	20	Meters	25		5500	27	Interval Meters	15	NA
	5500	21	Interval Meters	25		5510	28	Meters (Dumb)	25	NA
	5500	22	Suite Meters	25		5520	29	Suite Meters	15	NA
	5600	23	Meters Electronic	15		5600	30	Smart Meters	15	NA
1945	5700	24	Measurement & Testing Equipment	10		5700	31	Measurement & Testing Equipmnt	10	NA
1815	5900	25	Stn. Equip. > 50 kV	40		5900	32	Stn. Equip. > 50 kV Other	25	NA
				40		5910	33	Station Switchgear >50kV	40	NA
				40		5920	34	Station transformers >50 kV	45	NA
	5500	26	Wholesale Meters	25		5930	35	Wholesale Meters >50 kV	15	NA
1820	6100	27	Stn. Equip. < 50 kV	30		6100	36	Stn. Equip. <50kV Other	25	NA
				30		6110	37	Station Switchgear <50kV	40	NA
				30		6120	38	Station transformers <50 kV	45	NA
	5500	28	Wholesale Meters	25		6130	39	Wholesale Meters< 50kV	15	NA
1985	6300	29	Sentinel Lighting Rental Units	10		6300	40	Sentinel Lighting Rental Units	10	NA
1980	6500	30	System Supervisory Equip. SCADA (see 1920 & 1925 for computer hardware and software)	15		6500	41	SCADA RTU,Relays,Com Equipmnt	15	NA

Hydro Ottawa Limited
Components and Estimated Useful Lives

OEB Cost Code	Original Cost Code		Original Asset Components	OEB Depreciation (years)		New Cost Code		New Asset Components	IFRS Life (years)	Residual Value Estimate
Tangible Assets (continued)										
1845	6700	31	U/G Conductor, Devices	25		6700	42	U/G Polymer Insulated Cable	35	NA
				25		6710	43	U/G Switchgear & Reclosers	25	NA
				25		6720	44	Vault Switchgear and Reclosers	30	NA
				25		6730	45	U/G PILC Cable	60	NA
1840	6900	32	U/G Conduit and cable chambers	25		6900	46	U/G Conduit and cable chambers	40	NA
1850	7500	33	Line Transformers	25		7500	47	Line Transformers O/H & U/G	30	NA
	7510			25		7510	48	Line Transformers Vault	35	NA
1835	8100	34	O/H Conductor, Devices Switchgear and Reclosures	25		8100	49	O/H Conductors and Non-Automated Devices	45	NA
				25		8110	50	O/H Automated Devices	25	NA
1830	8300	35	Poles, Towers, Fixtures	25		8300	51	Poles, Towers, Fixtures	45	NA
1855	8500	36	Services	25		8500	52	Services	45	NA
2070	7300	37	Other Utility Building	NA		7300	53	Other Residential Building	25	NA
						7310	54	Other Commercial Building	50	NA
	7100	38	Other Utility Property	NA		7100	55	Other Utility Property	NA	NA
Intangible Assets										
1806	1300	39	Land Rights - Distribution	50		1300	56	Land Rights - Distribution	50	NA
1906	1300	40	Land Rights - General	50		1310	57	Land Rights - General	50	NA
1610						1400	58	Line Connection Contribution	45	NA
1925	2500	41	Computer Software Regular	5		2500	59	Cmptr Software Regular	5	NA
1925	2500	42	Computer Software 10 Yrs	10		2510	60	Cmptr Software 10 Yrs	10	NA

Number of Original Components
42

Number of New Components
60

Increase
18

Legend: HOL does not use these assets or only a very small number exist in the system

Colors represent components that HOL Grouped together

PARENT*	#	ASSET DETAILS		Kinectrics USEFUL LIFE			KINECTRICS FACTORS **						HOL New IFRS	IFRS LIFE	% Diff from	Old OEB	Comments
		Category - Component - Type		Min	Typ	Max	MC	EL	EN	OP	MP	NPF	Components		Typical	LIFE	
T r a n s f o r m e r a n d M & u n i c i p a l S t a t i o n s	12	Power Transf	Overall	30	45	60	NI	M	M	L	L	NI	Station Transformers >50 kV & <50kV	45	0%	40 & 30	Replace entire asset at once, tap changers for example do not fit on new transformers therefore can't replace transformer and keep old tap changer.
			Bushing	10	20	30											
			Tap Changer	20	30	60											
	13	Station Service Transformer		30	45	55	NI	L	M	L	NI	L	Line Transformers Overhead &	30	-33%	25	9,13 & 34 grouped together
	14	Station Grounding Transformer		30	40	40	-	-	-	-	-	-					
	15	Station DC System	Overall	10	20	30	NI	M	L	L	M	M	Other Stn. Equip. >50kV & < 50 kV	25	25%	40 & 30	Changed all at once - newer batteries are lasting longer
			Battery bank	10	15	15											
			Charger	20	20	30											
	16	Station Metal Clad Switchgear	Overall	30	40	60	L	L	M	M	M	M	Station Switchgear >50kV & <50kV	40	0%	40 & 30	16, 17, 18, 19, 22, and 23 grouped together as one component but hardly any 22 or 23 in system
			Removable Breaker	25	40	60											
	17	Station Independent Breakers		35	45	65	M	M	M	M	M	M	Station Switchgear >50kV & <50kV	40	-11%	40 & 30	
	18	Station Switch		30	50	60	M	L	M	M	M	L	Station Switchgear >50kV & <50kV	40	-20%	40 & 30	
	19	Electromechanical Relays		25	35	50	NI	NI	NI	NI	NI	H	Station Switchgear >50kV & <50kV	40	14%	40 & 30	
	20	Solid State Relays		10	30	45	NI	NI	NI	NI	NI	H	SCADA RTU, Relays, Communication Equipment	15	-50%	15	20, 21 and 43 grouped together
	21	Digital & Numeric Relays		15	20	20	NI	NI	NI	NI	NI	H	SCADA RTU, Relays, Communication Equipment	15	-25%	15	
	22	Rigid Busbars		30	55	60	L	L	L	NI	NI	L					16, 17, 18, 19, 22, and 23 grouped together as one component but hardly any 22 or 23 in system
	23	Steel Structure		35	50	90	L	NI	M	NI	NI	L					

Legend: ████████ HOL does not use these assets or only a very small number exist in the system

Colors represent components that HOL Grouped together

PARENT*	#	ASSET DETAILS		Kinetrics USEFUL LIFE			KINETRICS FACTORS **						HOL New IFRS	IFRS LIFE	% Diff from	Old OEB	Comments	
		Category - Component - Type		Min	Typ	Max	MC	EL	EN	OP	MP	NPF	Components		Typical	LIFE		
Underground Systems (UG)	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	L	L	M	L	NI	M	U/G PILC Cable	60	-8%	25	25, 26, 27, 28 and 29 grouped together as one component this is the main reason for the deviation against the Kinetrics lives	
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	NI	M	L	NI	NI	NI	U/G Polymer Insulated Cable	35	40%	25		
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables - Direct Buried		20	25	30	M	M	M	L	L	L	U/G Polymer Insulated Cable	35	40%	25		
	27	Primary Non-TR XLPE Cables - In Duct		20	25	30	M	M	M	L	L	M	U/G Polymer Insulated Cable	35	40%	25		
	28	Primary TR XLPE Cables - Direct Buried		25	30	35	M	M	M	L	L	L	U/G Polymer Insulated Cable	35	17%	25		
	29	Primary TR XLPE Cables - In Duct		35	40	55	M	M	M	L	L	L	U/G Polymer Insulated Cable	35	-13%	25	30, 31, 32 grouped together as one component this is the main reason for the deviation against the Kinetrics lives	
	30	Secondary PILC Cables		70	75	80	NI	L	L	NI	NI	H	Services	45	-40%	25		
	31	Secondary Cables - Direct Buried		25	35	40	M	M	M	L	NI	NI	Services	45	29%	25		
	32	Secondary Cables - In Duct		35	40	60	M	M	M	L	NI	NI	Services	45	13%	25		
	33	Network Transformers	Overall	20	35	50	NI	L	H	NI	NI	NI						
			Protector	20	35	40												
	34	Pad-Mounted Transformers		25	40	45	L	M	M	NI	L	L	Line Transformers	30	-25%	25	9,13 & 34 Grouped together	
	35	Submersible Vault Transformers		25	35	45	L	M	M	NI	L	L	Line Transformers Vault	35	0	25		

Legend: HOL does not use these assets or only a very small number exist in the system

Colors represent components that HOL Grouped together

PARENT*	#	ASSET DETAILS		Kinectrics USEFUL LIFE			KINETRICS FACTORS **						HOL New IFRS	IFRS LIFE	% Diff from	Old OEB	
		Category - Component - Type		Min	Typ	Max	MC	EL	EN	OP	MP	NPF	Components		Typical	LIFE	
S u n d e r m o u n d (U G)	36	UG Foundations		35	55	70	M	NI	M	L	L	M	U/G Conduit and cable	40	-27%	25	36, 37, 40, 41 & 42 grouped together as one component
	37	UG Vaults	Overall	40	60	80	M	NI	M	L	L	L	U/G Conduit and cable chambers	40	-33%	25	
			Roof	20	30	45											
	38	UG Vault Switches		20	35	50	L	L	L	L	L	NI	Vault Switchgear and Reclosers	30	-14%	25	
	39	Pad-Mounted Switchgear		20	30	45	L	L	H	L	L	L	U/G Switchgear and Reclosers	25	-17%	25	
	40	Ducts		30	50	85	H	NI	M	NI	NI	L	U/G Conduit and cable chambers	40	-20%	25	36, 37, 40, 41 & 42 grouped together as one component this is the main reason for the deviation against the Kinectrics lives
	41	Concrete Encased Duct Banks		35	55	80	M	NI	M	NI	NI	L	U/G Conduit and cable	40	-27%	25	
42	Cable Chambers		50	60	80	M	NI	H	NI	L	NI	U/G Conduit and cable chambers	40	-33%	25		
Monitoring and Control Systems (S)	43	Remote SCADA		15	20	30	NI	NI	L	NI	L	H	SCADA RTU,Relays,Communica tion Equipment	15	-25%	15	20, 21 and 43 grouped together

Technical Conference Question

c) [J2-1-1, J2-1-2, and K11, 11.1, Energy Probe #64] Please recalculate Tables 1 through 3 of J2-1-1, and the continuity schedules in J2-1-2, and Tables 1 through 6 of the Energy Probe IR response, using the Typical Lives set out in the Kinectrics Report.

Response

Hydro Ottawa Limited (Hydro Ottawa) has undertaken a rudimentary illustrative analysis in order to respond to School Energy Coalition's (SEC) request for information that compares components and service lives determined by Hydro Ottawa for the purposes of depreciation under International Financial Reporting Standards (IFRS) with the Typical Useful Lives set out in the Kinectrics Report.

As discussed with counsel for the SEC, Hydro Ottawa's IFRS analysis was the result of many months of effort that involved, among other things, the determination of IFRS compliant asset components to which costs should be assigned, applicable service lives, and the allocation of opening balance sheet costs to such components. The analysis was completed by Hydro Ottawa accountants, engineers and operating staff, and reviewed by IFRS project partner Ernst & Young.

In order to provide the information sought by SEC, Hydro Ottawa's engineering staff applied judgment as to how to allocate opening net book values to the full range of Kinectrics asset components, even though many of the components are not applicable to Hydro Ottawa's circumstances. Modelling worksheets were expanded to allow for additional components, allocation percentages were estimated and the depreciation models were re-run. The result of this work is by no means a rigorous and accurate calculation and, in any event, Hydro Ottawa does not accept that the comparison that SEC seeks to make to the Kinectrics Report is either appropriate or relevant. Subject to these comments, the information sought by SEC is provided as Attachment 1.



List of Components with differing depreciation lives between Hydro Ottawa and Kinectrics Typical Life

Hydro Ottawa				Kinectrics		One to One Relationship			One to Many Allocation			
		Related	NBV \$\$\$			Using			Using			
Component name		UsofA	Opening	Component Name		Actual	Kinectrics	Variance	Actual	Kinectrics	Variance	Allocation
		Life	Balance Sheet									
1	Line Transformers Overhead & Undergrounc	1850	30	31,115,669	OH Transformers & Voltage Regulators	40			2,220,575	1,525,203	(695,372)	100% @ 40 yrs
					Station Service Transformer	45						
					Pad-Mounted Transformers	40						
2	U/G Polymer Insulated Cable	1845	35	30,447,584	Primary Ethylene-Propylene Rubber (EPR) Cable:	25			2,338,961	2,162,158	(176,803)	60% @ 40 yrs, 40% @ 25 yrs
					Primary Non-Tree Retardant (TR) Cross Linked	25						
					Primary Non-TR XLPE Cables - In Duct	25						
					Primary TR XLPE Cables - Direct Buriec	30						
					Primary TR XLPE Cables - In Duct	40						
3	U/G Switchgear and Reclosers	1845	25	10,576,568	Pad-Mounted Switchgear	30	905,513	595,773	(309,740)			
4	Vault Switchgear and Reclosers	1845	30	2,090,705	UG Vault Switches	35	126,986	97,712	(29,273)			
5	U/G PILC Cable	1845	60	12,310,233	Primary Paper Insulated Lead Covered (PILC)	65	336,753	304,313	(32,440)			
6	O/H Conductors & Non-Automated Devices	1835	45	34,028,029	OH Conductors	60	1,063,383	762,244	(301,139)			
7	O/H Automated Devices	1835	25	4,492,287	OH Line Switch	45						
					OH Line Switch Motor	25						
					OH Line Switch RTU	20						
					OH Integral Switches	45						
					Reclosers	40						
8	Other Stn. Equip. >50kV	1815	25	10,690,313	Station DC System - Overall	20	701,120	873,130	172,010			
9	Other Stn. Equip. < 50 kV	1820	25	9,905,464	Station DC System - Overall	20	1,006,110	1,138,236	132,126			
10	Station Switchgear >50kV	1815	40	20,737,464	Station Metal Clad Switchgear - Overal	40						
					Station Independent Breakers	45						
					Station Switch	50						
					Electromechanical Relays	35						
					Rigid Busbars	55						
					Steel Structure	50						
11	Station Switchgear <50kV	1820	40	13,224,604	Station Metal Clad Switchgear - Overall	40						
					Station Independent Breakers	45						
					Station Switch	50						
					Electromechanical Relays	35						
					Rigid Busbars	55						
					Steel Structure	50						
12	U/G Conduit and cable chambers	1840	40	50,093,508	UG Foundations	55						
					UG Vaults - Overall	60						
					Ducts	50						
					Concrete Encased Duct Banks	55						
					Cable Chambers	60						
13	Services	1855	45	38,245,623	Secondary PILC Cables	75						
					Secondary Cables - Direct Buried	35						
					Secondary Cables - In Duct	40						
14	SCADA RTU,Relays,Communication Equipment	1980	15	6,635,386	Solid State Relays	30						
					Digital & Numeric Relays	20						
					Remote SCADA	20						
TOTALS							4,139,865	3,771,409	(368,456)	11,102,887	9,428,446	(1,674,441)
Components that do not require a further breakdown of the opening balance sheet NBV (6 out of 14)												

1 Executive Summary

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives and time based maintenance schedules, for THESL's assets.

Table 1-1 THESL Summary of Componentized Assets

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years)			Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
					Min	Typical	Max		
2	Wood Pole (Fully Dressed)		OH	40 feet	40	44	50	RI	15
3	Concrete Pole		OH	40 feet	50	60	60	RI	15
4	Remotely Operated Overhead Switch		OH	Not Available	30	45	50	RTM	2
5	Manually Operated Overhead Switch		OH	600A, 28KV, SWITCH, MANUAL, UPRIGHT MTG	30	50	60	RTM	2
6	SCADAMATE Overhead Switch		OH	SWITCH, 28KV, 600A, SCADA CONTROLLED	30	45	50	RTM	2
7	Overhead Primary Conductor	Primary Bare	OH	WIRE 556 ASC (DAHLIA) AS PER THES SPEC	50	60	77		n/a
		Primary Tree Proof	OH	CABLE 336 ASC 15kV TREE PROOF	50	60	77		
8	Overhead Secondary Conductor		OH	TRIPLEX 2- 266.8 AL XLPEI 1- 3/0 stock code # 7155236	50	60	77		n/a
9	Pole Mounted Transformer		OH	POLEMOUNT, 1PH, 100KVA, 16kV	30	40	40		n/a
10	Lighting Assemblies (High Mast)	Pole (Highmast)	OH	Not Available	60	70	80	RTM	2
		Cabling		Not Available	40	40	60		2
		Luminaire		Not Available	20	25	30		2
11	Power Transformer (>10MVA, >50kV)	Overall	TS	75/100/125MVA, 230kV/28kV	32	45	55	RTM	2
		Winding			32	45	55		
		Bushing			12	15	20		
		Tap changer			20	30	30		
12	230 kV Steel Structures and Overhead Bus Work	Steel structure	TS	Cavanagh TS 230kV bus structure	35	50	100		n/a
		Busbar			30	60	60		
13	Outdoor Station Disconnect Switch (230 kV)		TS	1200A, 230kV	30	45	50	RTM	5-8

* OH = Overhead Lines System TS = Transmission Station MS = Municipal Station UG = Underground System

** RI = Routine Inspection RTM = Routine Testing/Maintenance

1 Executive Summary

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years)			Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
					Min	Typical	Max		
14	TS AC Station Service	Transformer	TS	300kVA	32	45	55	RTM	3
		LV Switchgear	TS	1600A	40	40	60		3
15	Power Transformer (>2.5MVA and <10MVA, <50kV)	Overall	MS	5/6.7MVA, 27.6/4kV	32	45	55	RTM	2
		Winding			32	45	55		
		Bushing			12	15	20		
		Tap Changer			20	30	30		
16	Station Steel structures and Overhead Bus Work (<50kV)		MS	Bus structure for 27.6kV/4kV for 2 of 5MVA transformers	35	50	100	RI	n/a
17	Outdoor Station Disconnect Switch (<50kV)		MS	600A, 27.6kV	30	45	50	RTM	5-8
18	MS AC Station Service	Transformer	MS	75kVA	32	45	55	RTM	3
		AC Panel	MS	200-275A	40	40	60		
19	DC Station Service	Overall	TS,MS	85-100AH, 125V To be matched with battery size	10	20	30	RTM	1
		Battery bank			10	20	30		
		Charger			20	20	30		
20	Indoor Station Disconnect Switch (<50kV)		TS,MS	600A Gang, LBS, 4kV	30	45	50	RI	5-8
21	Oil Breaker (Outdoor)		TS,MS	1200A, 13.8kV	30	42	60	RTM	3
22	SF6 Breaker (Outdoor)		TS,MS	2500A, 13.8kV or 1200A, 27.6kV	30	42	60	RTM	3
23	Vacuum Breaker (Outdoor)		TS,MS	3000A, 13.8kV or 1200A, 27.6kV	30	40	60	RTM	3
24	Oil Breaker (Indoor)		TS,MS	1200A, 13.8kV	30	42	60	RTM	3
25	SF6 Breaker (Indoor)		TS,MS	1200A, 13.8kV	30	42	60	RTM	3
26	Vacuum Breaker (Indoor)		TS,MS	1250A, 13.8kV	30	40	60	RTM	3
27	Air Blast Breaker (Indoor)		TS,MS	1200A, 13.8kV	30	40	50	RTM	3
28	Air Magnetic Breakers (Indoor)		TS,MS	1200A, 13.8kV	25	40	60	RTM	3
29	Metalclad/Metal Enclosed Switchgear (Air)		TS, MS	3000A, 13.8kV	40	50	60	RTM	6
30	Metalclad/Metal Enclosed Switchgear (GIS)		TS, MS	3000A, 13.8kV	40	50	60	RTM	6
31	Station Grounding System		TS,MS	15 ground rods 100' x 100' lot 13.8kV station	25	40	50		n/a
32	Station Grounding Transformer		TS,MS	13.8kV, 250A per phase for 1 minute	30	40	40	RI	3
33	SCADA RTU		TS,MS	Medium station, 13.8kV, 30 feeders	15	20	30		n/a
34	Automatic Transfer Switch		UG	Not Available	30	45	50	RI	3
35	Network Transformer	Network Unit	UG	750kVA, 120/208V	20	35	50	RI	2
		Protector Unit	UG	3000A, 120/208V	20	35	40		2
36	Pad Mounted Transformer		UG	1PH, 100KVA, 16kV	30	40	40	RI	n/a
37	Vault Transformer		UG	1PH, 100KVA, 16kV	30	40	40	RI	2
38	Submersible Transformer		UG	1PH, 100KVA, 16kV	25	35	40	RI	2

* OH = Overhead Lines System TS = Transmission Station MS = Municipal Station UG = Underground System

** RI = Routine Inspection RTM = Routine Testing/Maintenance

1 Executive Summary

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years)			Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
					Min	Typical	Max		
39	Network Vault	Overall	UG	2.3mW x 6.4mL x 3.4mH (I.D.)	40	60	80	RTM	3
		Roof		2.3mW x 6.4mL	20	25	30	RTM	3
40	Radial Vault	Overall	UG	3.0m W x 8.5m L x 3.66m H (I.D.)	40	60	80	RTM	3
		Roof		3.0m W x 8.5m L	20	25	30	RTM	3
41	URD Vault	Overall	UG	1.5m W x 3.5m L x 2.1m H (I.D.)	40	60	80	RTM	3
		Roof		1.5m W x 3.5m L	20	25	30	RTM	3
42	Submersible Vault	Overall	UG	1.24m W x 2.26m L x 1.98m H (I.D.)	40	60	80	RTM	3
		Roof		1.24m W x 2.26m L	20	25	30	RTM	3
43	Cable Chamber	Overall	UG	2.5m W x 3.0m L x 2.5m Headroom (I.D.)	50	60	80	RTM	3
		Roof		2.5m W x 3.0m L	20	25	30	RTM	3
44	Duct Bank		UG	3W x2H	30	50	80		n/a
45	Padmounted Switchgear (SF6/Vacuum)		UG	Not currently in our standard coming soon, VISTA or SF6 Canada power	30	30	50	RI	3
46	Padmounted Switchgear (Air Insulated)		UG	SWITCHGEAR 600A, PADMOUNTED, MANUAL, PMH-11, 28kV stock code #6910012	20	20	40	RI	3
47	SF6/Vacuum Underground Switch		UG	Loadbreak, Vacuum, 3PH, 15KV, 200AMP, 2-WAY 1-SW or 3-WAY 3-SW	30	30	50	RI	3
48	UG Primary Cable (XLPE in Duct)		UG	1/0 AL 28KV TRXLPE ECNPEJ. AS PER stock code #7180052	40	40	60		n/a
49	UG Primary Cable (XLPE DB)		UG	1/0 AL 28KV TRXLPE ECNPEJ. AS PER stock code #7180052	20	25	25		n/a
50	UG Primary Cable (PILC)		UG	500 KCMIL 3C CU 15KV PILC, AS PER stock code #7160040	70	75	80		n/a

* OH = Overhead Lines System TS = Transmission Station MS = Municipal Station UG = Underground System

** RI = Routine Inspection RTM = Routine Testing/Maintenance

1 Executive Summary

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years)			Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
					Min	Typical	Max		
51	UG Secondary Cable (In Duct)		UG	CABLE 500 KCMIL CU XLPE 600V AS stock code 7150274	40	40	60		n/a
52	UG Secondary Cable (DB)		UG	CABLE 500 KCMIL CU XLPE 600V AS stock code 7150274	20	25	25		n/a
53	Lighting Assemblies (Conventional)	Cabling	UG	Not Available	40	40	60	RI	4
		Civil (handwell, tap box)		Not Available	50	50	60		
		Pole		Not Available	40	50	60		
		Luminaire		Not Available	20	25	30		
* OH = Overhead Lines System TS = Transmission Station MS = Municipal Station UG = Underground System ** RI = Routine Inspection RTM = Routine Testing/Maintenance									

Table 1: USoA Accounts

USoA account number	USoA account description	USoA sub-account number	IFRS Asset Categories (Components)	Component Description	OEB prescribed useful life	Revised useful life per IAS 16
1610	Miscellaneous Intangible Plant	1610	1610001	Intangible Assets - Computer Software	5	5
		1610	1610002	Intangible Assets - T.S. Contributions	40	40
1805	Land	1805	1805001	Land	Not depr.	Not depr.
1806	Land Rights	1806	1806001	Land rights - Indeterminate	Not depr.	Not depr.
		1806	1806002	Land rights - Finite	Variable	Variable
1808	Buildings & Fixtures	1807	1808002	Buildings - Brick	50	50
		1809	1808001	Sandalwood Building	50	50
1815	Trans Station Equipment	1815	1815001	TS Transformers & Tap Changers	40	40
		1815	1815002	TS Primary HV Switches	40	30
		1815	1815003	TS Protection/Auto transfer sys & ancillary equipment	40	20
		1815	1815004	Bus Work & Cubicles	40	40
		1815	1815005	TS Breakers & Reclosures & Local Control Sys	40	40
		1815	1815006	TS Battery Systems & Chargers / Inverters	40	10
		1815	1815007	TS Station Service Equipment	40	40
		1815	1815008	TS Cables & Terminations	40	30
		1815	1815009	TS Instrument Transformers (It's)	40	40
		1815	1815010	TS Station Meters	40	10
		1815	1815012	TS Ancillary Metering Equipment	40	10
1820	Dist Station Equipment	1820	1820001	MS Transformers & Tap Changers	30	40
		1820	1820002	MS Primary HV Switches	30	30
		1820	1820003	MS Protection/Auto Transfer Sys & Ancillary Equip	30	20
		1820	1820004	MS Bus Work & Cubicles	30	40
		1820	1820005	MS Breakers & Reclosures & Local Control Syst.	30	40
		1820	1820006	MS Battery Systems & Charges / Inverters	30	10
		1820	1820007	MS Station Service Equipment	30	40
		1820	1820008	MS Cables & Terminations	30	30
		1820	1820009	MS Instrument Transformers (It's)	30	40
		1820	1820010	MS Station Meters	25	15
1830	Poles, Towers & Fixtures	1830	1830001	Poles - Wood	25	40
		1830	1830002	Poles - Non Wood	25	50
1835	OH Conductors & Devices	1835	1835001	O/H Prim Main Ln Conductors Inc. Neutral & Ln Arrest	25	50
		1835	1835002	Secondary Main Line Conductors	25	50
		1835	18350004	Switches	25	25
1840	Underground Conduit	1840	1840001	Underground Conduit - Direct Buried	25	50
		1840	1840002	Underground Conduits - Concrete Encased	25	75
1845	U/G Conductors and Devices	1845	1845001	Primary Cables	25	30
		1845	1845004	Switches and Switchgear	25	30
		1845	1845010	Underground Secondary Cables	25	50
1850	Line Transformers	1850	1850001	Overhead Transformers	25	40
		1850	1850002	Underground Transformers	25	40
1855	Services	1855	1855001	All Low Voltage (120 - 600V) O/H Services	25	50
		1855	1855002	U/G/ Low Voltage (120 - 600V) Services	25	50
1860	Meters	1860	1860001	Non-IT based Meters	15	15
		1860	1860002	IT based Meters	15	15

1908	Buildings & Fixtures	1908	1908001	Solar Panels	25	25
1915	Office Furniture & Equipment	1915	1915001	Office Furniture and Equipment	10	10
1920	Computer Equipment - Hardware	1920	1920001	Servers, Desktops, Sans	5	5
1930	Transportation Equipment	1930	1930001	Automobiles	4	7
		1930	1930002	Trucks Under 3 Tonnes	5	10
		1930	1930003	Trucks Over 3 Tonnes / Trailers	8	10
1935	Stores Equipment	1935	1935001	Stores Equipment	10	10
1940	Tools, Shop and Garage Equip	1940	1940001	Tools, Shop and Garage Equip.	10	10
1950	Power Operated Equipment	1950	1950001	Power Operated Equipment	8	8
1955	Communication Equipment	1955	1955001	Communication Equipment	10	10
1960	Miscellaneous Equipment	1960	1960001	Miscellaneous Equipment	10	10
1980	Supervisory Control Equipment	1980	1980001	Remote Switch SCADA Battery	15	7
		1980	1980002	Remote Switch SCADA Motor Operator	15	15
		1980	1980003	Remote Switch SCADA Enclosures and Equipment	15	15

Capitalization

Issue 3.3: Should the Board require PP&E to conform to IFRS capitalization requirements (e.g., capitalize less indirect overhead and administration cost than permitted under current Canadian GAAP)?

In contrast to the consensus that developed around the two proposals above, there was no agreement regarding whether the Board should require utilities to adhere to IFRS capitalization principles. The proposal tabled by Board staff on this issue read:

3.3 The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS. The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first rate filing after IFRS adoption.

At the time of the stakeholder conference, it appeared that fewer overhead and administrative costs would be considered capital expenditures under IFRS than is the case under current CGAAP accounting. Some of the reduction in capitalization might result from increased scrutiny of capitalization of expenses undertaken by utilities and their auditors, rather than actual changes in accounting rules. Nevertheless, a reduction in capitalization of expenses would, all other things being equal, result in more costs being expensed in the current period and a consequent increase in near-term revenue requirements.

Data collected by Board staff indicated that the actual effect of the adoption of IFRS capitalization principles would vary greatly among utilities. Those utilities who at present capitalize significant overhead and administrative costs may see some, and potentially significant, shifting of costs to the current period. Some utilities may experience no cost shifting, or even a shift from current expenses to capital. The magnitude of the shift, if any, is not yet known by the utilities.

The ratepayer participants generally submitted that the Board should not decide on the adoption of IFRS capitalization rules at this time, as the potential rate impacts of such a change are unknown, are at present unknowable, and could be significant. The regulatory principle of minimizing intergenerational inequity could be violated and potentially significant rate impacts could arise if utilities alter their capitalization policies to conform to IFRS principles. The majority of ratepayer groups urged the Board not to decide until reliable evidence of the magnitude of rate impacts is available.

The electricity utilities in general supported the adoption of IFRS capitalization rules for regulatory purposes, and argued that any undue rate impacts could be mitigated. The effort involved in keeping two sets of asset ledgers if IFRS capitalization rules were not adopted for regulatory purposes would increase costs to the utilities and their ratepayers.

CCC, alone among the ratepayer participants, supported the adoption of IFRS capitalization principles, arguing that indirect costs such as overhead and

administrative costs should not be capitalized and added to rate base, as such practices ultimately increase total costs to ratepayers. CCC pointed out that capitalization policies vary widely among utilities, and suggested that the Board take the opportunity of the transition to IFRS to standardize regulatory accounting. CCC submitted:

“Overheads and administrative costs are often fixed, subject to low volatility or immaterial as a percentage of capital expenditure. Expensing these costs directly should have little or no impact on rate volatility in the long term. However, rate volatility may be relevant if there are transitional impacts of standardizing the regulatory accounting principle for all Board-regulated utilities. The transitional impacts would dissipate as capitalized overheads already embedded in rate base are expensed through depreciation.

On a utility-specific basis, once the rate-making impacts of transitioning from the current status quo to the standardized regulatory accounting principles are known, rate mitigation techniques could be considered by the Board.”

The Board agrees with the analysis provided by CCC. It appears to the Board that the capitalization principles as they now appear in IFRS recognize the nature of indirect costs and whether they are truly attributable to capital projects. The ability of the Board to set just and reasonable rates is enhanced by clarity in capitalization principles that emphasize cost causality. The Board recognizes that rate mitigation may be necessary for some utilities where a reduction in capitalization of costs causes near-term rate impacts that are not otherwise mitigated by other business actions, such as reduction or redistribution of indirect activities, or organizational adjustments.

The extent of the rate mitigation that may be necessary is unclear. In addition to the variable effect of the adoption of IFRS capitalization principles on utilities described above, the Board understands that the IASB is also considering some modification of the capitalization requirements for regulated utilities and including this issue in its review of regulatory accounting, for which an exposure draft is expected in the second half of 2009.

The Board will address any need for mitigation in the rate applications of distributors.

It will be important for the Board to have a clear understanding of utility capitalization practices, and the effects, if any, of a shift to IFRS capitalization principles. The Board therefore supports the requirement for utilities to file their capitalization policies in their first cost of service filing after the transition to IFRS, and will also require that the revenue requirement impacts of any change in capitalization be specifically and separately quantified.

The Board’s approach is captured by the following:

3.3 The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS. The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first cost of service rate filing

after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified.

Other PP&E Related Items

Issue 3.4: What changes to existing regulatory or rate making treatments should the Board require for other PP&E related items as a result of the adoption of IFRS?

- ***Borrowing costs applied to PP&E (as opposed to deemed interest or AFUDC)***
- ***Customer contributions received for PP&E***
- ***Asset reclassifications from PP&E to intangible assets (e.g., computer software and land rights)***
- ***Asset retirement obligations***
- ***Gains and losses on disposition of assets***
- ***Treatment of asset impairment***

In relation to issue 3.4, staff proposed that the Board require utilities to adhere to IFRS accounting requirements for PP&E related items for regulatory purposes, with certain noted exceptions. The Board accepts this basic statement, and has reached conclusions on specific items as set out below.

1. Borrowing costs applied to PP&E

The staff proposal read as follows:

IFRS requires utilities to capitalize carrying charges associated with Construction Work in Progress (CWIP) using actual interest cost incurred as opposed to amounts calculated at rates prescribed by the regulator. On or before the date for adoption of IFRS, the Board will discontinue publication of market based rates for applying borrowing costs to CWIP. For regulatory rate making and reporting the Board will use the values calculated in accordance with IFRS to determine capitalized carrying charges on CWIP.

The Board notes that several participants questioned whether actual borrowing costs should be used for rate setting purposes where the debt is held by an affiliate of the distributor.

The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arm's length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the applicant should use the Board's published rates.

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

**Commission de l'énergie
de l'Ontario**
C.P. 2319
27^e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273



BY E-MAIL AND WEB POSTING

February 24, 2010

All Licensed Electricity Distributors
All Rate-Regulated Natural Gas Utilities

Re: Accounting for Overhead Costs Associated with Capital Work

The *Report of the Board on Transition to International Financial Reporting Standards* (IFRS), July 2009 (Board Report) addressed the topic of accounting for overhead costs in the cost of new capital works effective January 1, 2011 in Issue 3.3. The Board is providing a clarification on this issue to assist utilities with their transition to IFRS. This matter was covered extensively in consultations EB-2008-0104/0408 including a survey of distributors in April of 2009 concerning their overhead capitalization practices. The Board Report stated:

3.3 The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS. The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first cost of service rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified.

The Board has received a number of enquiries regarding application of this portion of the Board Report. The enquiries have arisen given that the International Accounting Standards Board (IASB) has issued a draft standard on Accounting for Rate-Regulated Activities that states that a utility can include in the cost of capital works, costs beyond those permitted by the base IFRS standard (IAS 16 - Property, Plant & Equipment) if the regulator allows it and provides sufficient assurance of recoverability. The enquiries have been whether the Board would continue to allow capitalization of administration and other general overhead costs (currently explicitly prohibited by IAS 16, paragraph 19¹) for distributors currently doing so, if the standard were approved.

¹ The test generally applied to determine which overhead costs may be capitalized under IAS 16 is that they be costs that would have been avoided only if the specific asset had not been constructed or acquired. Employee benefits costs are included as an example of directly attributable costs (IAS 16, paragraph 17 (a)).

This letter is to clarify that the Board's position on Issue 3.3 from the Board Report applies independently of what the approval outcome of the IASB draft standard may be, as follows:

- As stated in the Board Report at Issue 3.3, the Board is requiring full compliance with IFRS requirements (e.g., IAS 16) as applicable to non-regulated enterprises and only where the Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.
- Based on IFRS consultations EB-2008-0104/0408 survey results this may mean a reduction in capitalized overhead for some electricity distributors that have previously capitalized administration and other general overhead costs no longer permitted under IFRS. It may mean an increase for those that have capitalized little or no overhead costs in the past. This includes those that have not capitalized such costs as specific capital project engineering costs, the cost of vehicles used in construction and employee benefits costs for staff working on specific capital projects. Benefits costs include but are not limited to statutory benefit costs, medical plan costs, pension costs and the cost of vacation time, holiday time and sick leave (IAS 19 – Employee Benefits).

Utilities are also reminded that the Board Report addresses a number of regulatory accounting, rate application and reporting matters related to the transition to IFRS including the impacts of any policy changes experienced by utilities.

Please direct any questions regarding this matter to the Market Operations Hotline at 416-440-7604 or by e-mail addressed to market.operations@oeb.gov.on.ca. The Board's toll free number is 1-888-632-6273.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

cc. All Participants in Board Consultation on Transition to IFRS (EB-2008-0408)



Overall, depreciation expense will be reduced since the IFRS lives are generally longer than the rates previously prescribed by the Board. As shown in Table 4, the total reduction in depreciation expense for the 2012 Test year is \$8.0M.

Table 4 –CGAAP and MIFRS Depreciation for 2012 Test Year

	\$M
CGAAP Depreciation Expense (Exhibit B2-2-1, Table 7)	\$47.4
MIFRS Depreciation Expenses (Exhibit J2-1-3, Table 2)	39.4
Reduction in Depreciation Expense	\$8.0

2.2 Capitalization

IAS 16 also indicates that only costs that are directly attributable to a specific asset can be capitalized. IAS 16 specifically prohibits the capitalization of administration and other general overhead costs.

In Section 3.3 of the Board's IFRS Guidance, the following guidance is provided regarding capitalization:

"The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS. The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first cost of service rate filing after IFRS adoption..."

In its letter dated February 24, 2010, the Board indicated that:

- "the test generally applied to determine which overhead costs may be capitalized under IAS 16 is that they be costs that would have been avoided only if the specific asset had not been constructed or acquired..."
- "based on IFRS consultations EB-2008-0104/0408 survey results this may mean a reduction in capitalized overhead for some electricity distributors that have previously capitalized administration and other general over costs ..."



1 Hydro Ottawa's current CGAAP capitalization practice includes capitalization of direct
2 costs such as materials and outside services (external contractors) directly to the capital
3 project. Labour costs and fleet costs are also allocated directly to the capital project
4 using time sheets. All of these costs are considered directly attributable to specific
5 assets and thus there are no changes to these costs because of IFRS.

6
7 Hydro Ottawa also capitalizes costs that are first charged directly to OM&A and then
8 allocated to capital projects through an overhead allocation methodology. The costs
9 allocated through an overhead allocation methodology include engineering costs,
10 supervision costs as well as costs referred to as the administrative allocation which
11 includes supply chain, facilities, human resources, information technology, finance,
12 regulatory, and other corporate costs. The amount of allocated costs will be significantly
13 reduced as a result of IFRS due to the fact that many of these costs are considered
14 administrative or other general overhead, which are specifically disallowed or cannot be
15 considered directly attributable to a specific asset.

16
17 Hydro Ottawa performed an analysis of the cost allocations to determine which amounts
18 will continue to be capitalized versus the amounts that are not considered directly
19 attributable and therefore do not meet the criteria for capitalization under IFRS. The
20 majority of the administrative burden was determined to be disallowable except for some
21 costs pertaining to the supply chain function. The engineering and supervision
22 allocations were also analyzed to determine which amounts could no longer be
23 capitalized. Much of the disallowable portion related to training, health and safety costs,
24 geographic information system and control room costs, future planning activities, and
25 manager and supervisory costs that could not be linked to a specific asset. Table 5
26 summarizes that the increase in OM&A as a result of the above-mentioned disallowable
27 costs is \$10.5M.



1 **Table 5 –CGAAP and MIFRS Capital Allocation for 2012 Test Year**

Type of allocation	CGAAP 2012 Test Budget \$M	MIFRS 2012 Test Budget \$M	Difference \$M
Labour and Fleet	\$20.9	\$20.9	\$0
Administrative	7.0	1.2	5.8
Engineering	4.4	1.8	2.6
Supervision	4.0	1.9	2.1
TOTAL	\$36.3	\$25.8	\$10.5

2
3 Hydro Ottawa’s capitalization policy as filed in Exhibit B1-3-1 will be updated prior to
4 January 1, 2012. The sections that will change include removal of any reference to
5 CGAAP to be replaced with IFRS, along with updating for IFRS terms and definitions.
6 The section on capitalized cost will also change significantly; currently it refers to the
7 following:

8 “Overhead costs must be directly attributable to capital construction activity at the
9 utility. This is interpreted to mean that the overhead costs to be charged to
10 capital are those that would not exist if Hydro Ottawa did not construct its own
11 capital assets. Eligible costs may appear fixed in the short term but would be
12 eliminated over time (in 3 to 5 years) if Hydro Ottawa did not have a capital
13 program. Overhead costs that are capitalized include such costs as salaries and
14 benefits for construction and engineering personnel not directly chargeable to
15 project costs and the cost of administrative and support services that are required
16 as a result of construction activity.”

17
18 As described above, the CGAAP policy referred to the entire capital program versus the
19 IFRS requirement that costs must be directly attributable to a specific asset.
20



11. MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS

Issue 11.1 - Is the proposed revenue requirement determined using modified IFRS appropriate?

Board Staff Question #80 - Ref: Exh J-1-1, p9

Please provide the following information in detail for overhead costs on self-constructed assets for the bridge and test years:

Nature of the overhead costs	Dollar Impact Bridge Year	Dollar Impact Test Year	Directly attributable? (Y/N)	Reasons why the costs are allowed to be capitalized under MIFRS given the more stringent limitations on capitalized overhead

Response

Table 5 in Exhibit J1-1-1 provides the overhead costs on self-constructed assets, an additional level of detail is provided in the table below. Comparisons provided are for the Test Year only, as that is considered the relevant comparator. The burden rate percentage prior to transition and after transition is noted at the bottom of the table.



1

Table 1 – CGAAP and MIFRS Overhead Costs for 2012 Test Year

Nature of overhead cost	CGAAP 2012 \$M	MIFRS 2012 \$M	Variance	Directly attributable (Y/N)	Reason why cost can be capitalized under MIFRS
Supply Chain	2.3	1.2	1.1	Y	Certain activities capitalized under CGAAP are not considered directly attributable to self-constructed assets. Amount remaining is directly attributable.
Facilities	1.0	0.0	1.0	N	
HR	1.7	0.0	1.7	N	
IT	0.2	0.0	0.2	N	
COO	0.1	0.0	0.1	N	
Finance	0.8	0.0	0.8	N	
Corporate	0.5	0.0	0.5	N	
Holding Company	0.3	0.0	0.3	N	
Regulatory	0.1	0.0	0.1	N	
Engineering	4.4	1.8	2.6	Y	Certain activities capitalized under CGAAP are not considered directly attributable to self-constructed assets. Amount remaining is directly attributable.
Supervision	4.0	1.9	2.1	Y	Certain activities capitalized under CGAAP are not considered directly attributable to self-constructed assets. Amount remaining is directly attributable.
Total	\$15.4	\$4.9	\$10.5		
CAPEX	\$92.0	\$92.0	\$92.0		
Burden Rate %	16.7%	5.3%	11.4%		

2

1 MS. SCOTT: It is the directly attributable.

2 MR. SHEPHERD: It is a breakdown of the overhead
3 costs. And so first that we have the confirmation that the
4 OM&A capital and the revenue-requirement figures and the
5 rates based on those figures that are contained throughout
6 the application use the CGAAP figures from this table and
7 not the modified IFRS tables, right?

8 MS. SCOTT: That is correct. All exhibits except for
9 J are in CGAAP.

10 MR. SHEPHERD: But what you are actually asking for
11 approval for -- I am sorry to go over it again, but I just
12 want to make sure I have the reference on the record -- is
13 the modified IFRS calculations.

14 MS. SCOTT: That's correct.

15 MR. SHEPHERD: Okay. Good.

16 So I wonder if you could just run through these and
17 just briefly tell us why each of these costs are considered
18 to be directly attributable or not directly attributable.

19 MR. SIMPSON: Sure.

20 MR. SHEPHERD: I don't need a long explanation, just
21 something to understand why some are Y and some are N.

22 MR. SIMPSON: Sure. Well, it could be a long answer,
23 as I believe you will understand, but essentially the
24 standard for IFRS is that the costs need to be specifically
25 attributable to an asset, directly and specifically
26 attributable to an asset. In our prior capitalization
27 policy we had a number of overhead-related costs,
28 facilities, HR, IT, executives, finance, corporate costs,

1 regulatory costs, which were allocated based on an overhead
2 percentage to the capital program as a whole.

3 Under IFRS those are essentially not considered
4 directly attributable. Those are kind of the simple
5 answer, those are out. Then many of those, as you will
6 see, if not all of those in the table in the exhibit, are
7 the ones that come across with an N. They're just not --

8 MR. SHEPHERD: SO that's things like HR and IT and --

9 MR. SIMPSON: Correct.

10 MR. SHEPHERD: -- the executive functions, things like
11 that.

12 MR. SIMPSON: Yes, as listed in the table there down
13 the left: Facilities, HR, IT, chief operating officers, et
14 cetera, which in the past, based on the document that we
15 distributed earlier, had a percentage allocation to the
16 capital program for their time.

17 MR. SHEPHERD: Now, in each of these cases, some part
18 of it may actually be directly attributable to an asset.
19 For example, if you have to have some people work overtime
20 in the IT department because they are running a model for a
21 -- to build an asset, you can charge that to the asset,
22 right?

23 MR. SIMPSON: Under the specific rules of IFRS, if
24 that was the case, yes, we likely could. If --

25 MR. SHEPHERD: But you don't actually do that.

26 MR. SIMPSON: We don't intend to do that as we go
27 forward. You will see those under supply chain engineering
28 and supervision, whereas we did go through those factors.

1 We are making a case to our auditors, essentially, that a
2 portion of that time is directly attributable, while not
3 all of it, from the previous capitalization policy, but
4 essentially, no, our -- for the overhead costs, they are
5 not directly attributable to a specific asset.

6 There may be a specific example somewhere along the
7 way we might be able to point to and argue, but as a
8 general rule finance, HR, IT are not considered directly
9 attributable to an asset under IFRS.

10 MR. SHEPHERD: Okay. And then with respect to the
11 ones that are partially included under IFRS, I am
12 particularly interested in engineering and supervision,
13 because I would have thought your engineering department,
14 that everything they do is on a project. Isn't that the
15 sort of management system you use in engineering?

16 MR. BENNETT: I am an engineer, not an accountant, so
17 right now all of the engineering is considered capital.
18 It's allocated as a capital -- as an engineering burden,
19 but the reality is that when you look at IFRS a lot of the
20 engineering time is looking at the future and not working
21 specifically on an asset.

22 So for example, the engineers are putting together the
23 asset management plan, putting together the five-year
24 program, but they are not necessarily working actually on
25 pole replacement or transformer replacement. They are not
26 charging their time directly to those projects. And the
27 way it was described to me, they need to be working
28 directly on the installation of the asset. So...

1 MR. SHEPHERD: The way you manage the engineering
2 department is on a project-management basis, right?
3 Engineers allocate their time to projects, true?

4 MR. BENNETT: Well, no. Let's be -- maybe I wasn't
5 clear.

6 So there is two groups in my group: the engineering
7 side, I will call it, the asset management group, and the
8 design group.

9 The design group charge their time. They manage all
10 the projects. There are a number of engineers within the
11 asset management group that work on specific large projects
12 like the stations capacity projects, but the majority of
13 the engineering asset management group works on the
14 planning side, so the capacity side, the reliability side,
15 the sustainment side, putting together plans and programs
16 that the others execute.

17 MR. SHEPHERD: So most of your engineering department,
18 then, doesn't work on doing -- and I don't mean this in a
19 negative way -- doesn't work doing conventional engineering
20 activities, in the sense of designing things or working on
21 the specific projects; the majority of your engineering
22 department's work is planning-oriented stuff, right?

23 MR. BENNETT: Yes. That's true.

24 MR. SHEPHERD: Okay. And the same, I guess, is then
25 true of supervision? It works the same way?

26 MR. BENNETT: Supervision is primarily in two
27 categories within this context, so the supervision, for
28 example, of the designers that I was previously talking

1 about, and then the supervision of the construction group.

2 Again, the supervisors aren't filling out time sheets
3 directly, and when we looked at the analysis, so they
4 absolutely participate in the supervision over some of the
5 project activity, but there is also significant other
6 activity that they are involved with as supervisors,
7 whether it's OM&A-type maintenance activity, operating
8 activity, training activity, all of that type of stuff.

9 MR. SHEPHERD: OM&A and training and operating stuff
10 would have been not capitalized before anyway, right?

11 MR. BENNETT: Well, the supervision burden is based on
12 the hours that are charged. So all of the capital hours
13 and all of the operating and maintenance hours have a
14 supervision burden.

15 So the split was based on how much dollars are spent
16 in those categories, so depending on which supervisor you
17 are, maybe most of your time would be covered in
18 supervision burden on capital or maybe most would be
19 covered on maintenance, operating-type activity.

20 MR. SHEPHERD: What I am trying to understand is:
21 Under what circumstances would a supervisor in this
22 context, involved on the capital side, not be supervising
23 on a project?

24 MR. BENNETT: Well, I will give you an example, which
25 happens all the time, right?

26 Customer calls and says: I want to build a Tim
27 Hortons. I am looking at the corner of Bruce and Spruce
28 here. Can you come and take a look?

1 The supervisor goes out, meets with them, looks at the
2 project, to see what he is going to have to do to get that
3 project to go, but the project doesn't happen this year.

4 MR. SIMPSON: And possibly never happens.

5 MR. BENNETT: It may never happen, but...

6 MR. SHEPHERD: Okay. And one other thing on this. I
7 didn't see fleet in here. Your fleet charges are treated
8 as directly attributable, right?

9 MR. SIMPSON: The fleet charges are treated as
10 directly attribute to capital projects when they are.

11 MR. SHEPHERD: And that's at your fleet burden rate?

12 MR. SIMPSON: Yes.

13 MR. SHEPHERD: And that's approved by your auditors?
14 They said that's okay?

15 MR. SIMPSON: Yes.

16 So just on that point, the table in the exhibit here -
17 - it sort of speaks to the engineering issue, as well -- is
18 just what we have previously allocated as overhead through
19 the capitalization policy.

20 MR. SHEPHERD: Sorry, I don't understand this.

21 MR. SIMPSON: So fleet was not considered overhead.
22 Much of Mr. Bennett's group specifically on engineering
23 projects was not considered part of an engineering
24 allocation.

25 This is the engineering allocation piece that has been
26 reviewed and reduced under the IFRS rules.

27 MR. SHEPHERD: Oh, see, that makes it a lot more
28 understandable. I thought 4.4 was the total engineering

1 cost, and then it seemed like not very much of it was going
2 to projects, but you already had some that was being
3 charged directly to the projects in the first place.

4 MR. SIMPSON: And will continue to be.

5 MR. BENNETT: Yes.

6 MR. SHEPHERD: And that's the bulk of it?

7 MR. SIMPSON: Yes.

8 MR. SHEPHERD: Okay. That makes that a lot more easy
9 to understand.

10 Then I have a couple of questions on Staff No. 90.
11 And you were asked questions about this yesterday, as well,
12 and I have read them and I still don't understand. That's
13 why I am following up.

14 And what you're doing is, because the capital cost of
15 a project is going down because of lower overhead
16 allocations, the calculation of the contribution goes down,
17 because you are starting with a lower number so you end up
18 with a lower number, right?

19 MR. SIMPSON: Correct.

20 MR. BENNETT: Correct.

21 MR. SHEPHERD: Okay. What I don't understand is those
22 overhead costs that were previously allocated as part of
23 the capital cost, they were -- they are, in fact, something
24 that you have to spend in order to connect the customer,
25 for example, if that's the capital contribution you are
26 talking about, so why aren't they included in calculation
27 as OM&A rather than as capital?

28 MR. SIMPSON: They are -- I just want to be clear on

1 which calculation you are asking about.

2 In the calculation of what we are applying to the
3 capital asset, that is what we have just been going
4 through. So the capital asset, the cost for the capital
5 asset will be reduced by the fact we have a change in our
6 capitalization policy under IFRS.

7 That's the answer to the calculation for the cost of
8 the asset.

9 MR. SHEPHERD: No, sorry, that's what I -- that's the
10 part I am having difficulty understanding.

11 The whole point of a contribution is that the money
12 you are spending is not economic, so the customer has to
13 give you a cheque, right? In essence?

14 MR. SIMPSON: The customer needs to pay for the asset
15 being...

16 MR. SHEPHERD: Or pay some part of it?

17 MR. SIMPSON: Yes.

18 MR. SHEPHERD: Not all of it, right? Some part of it?

19 MR. SIMPSON: Yes.

20 MR. SHEPHERD: And it's based on whether you are going
21 to recover enough on the asset to cover its capital cost,
22 and if you are not, they have to pay the difference, in
23 essence?

24 MR. BENNETT: Just to be clear, so the part that we
25 are talking about specifically is not as part of the OEB,
26 where we do a calculation. This is on the customer's
27 property.

28 So my Tim Hortons, you're going to install a pad mount

1 on the property. It's \$50,000 for the pad mount. The
2 customer pays me 100 percent for that cost.

3 In IFRS, the costs have come down, from the point of
4 view of all of the burden that we are talking about is not
5 there anymore.

6 So now my \$50,000 pad mount job is a \$45,000 pad mount
7 job.

8 MR. SHEPHERD: But your costs haven't actually come
9 down, right?

10 MR. BENNETT: The capitalized portion, right? So this
11 is a contributed capital project. You pay me 100 percent
12 for the contributed capital.

13 MR. SHEPHERD: What I am trying to understand is: You
14 are still spending the same amount of money; it's just some
15 of it is now being called OM&A rather than capital, right?

16 MR. BENNETT: Yes.

17 MR. SHEPHERD: So why isn't the customer being
18 required to contribute to the OM&A component that you
19 already -- that you know is part of the cost, the real
20 cost?

21 MR. BENNETT: They contribute to the capital portion.

22 MR. SHEPHERD: I ask why aren't they contributing to
23 the real cost.

24 MR. BENNETT: Well, today, they are not contributing
25 anything over and above the capital portion of the cost, so
26 we are applying the same principle tomorrow, and so...

27 MR. SIMPSON: The customer is billed the underlying
28 cost of the asset, and the costing rules are changing, and

1 we will continue to bill the customer the underlying cost
2 of the asset.

3 MR. SHEPHERD: All right. Have you looked at whether
4 the customer should pay some of the related OM&A?

5 MS. SCOTT: If I may, in the economic evaluation
6 formula, they will. When the OM&A, the incremental OM&A
7 goes up, so they will end up paying part of that through
8 the formula.

9 MR. SHEPHERD: Okay. Well, then, why would the
10 capital contributions go down?

11 MS. SCOTT: Because our -- we use the last approved
12 incremental OM&A in our formula. So it will take some time
13 to work this increased incremental cost. Like, right now,
14 we don't base our formula on the non-approved, new OM&A.

15 MR. SHEPHERD: So what it means is that for 2012, you
16 are stuck with 2011, which is CGAAP OM&A?

17 MS. SCOTT: Actually, 2008. It was our last approved.

18 MR. SHEPHERD: Well, 2008. There you go.

19 MS. SCOTT: Yes.

20 MR. SHEPHERD: But starting in 2013, you are actually
21 going to get these capital contributions back, right? They
22 will go back up to the previous number, because you will
23 have the new OM&A number to work with?

24 MS. SCOTT: I am not sure they will go back
25 immediately, like, it will be a one-for-one, immediate
26 going back totally.

27 What you use for the OM&A is an average incremental
28 cost for the class, so whether that's going to account for

1 all of -- in that particular class, I can't say.

2 I think the contributions will start to go back up.
3 Whether they would go back up to what they were, I can't
4 say.

5 MR. SHEPHERD: That's interesting. Okay.

6 And the final question on IFRS is -- and you may have
7 answered this yesterday. I am not sure.

8 We have referred to three exhibits, Energy Probe 63,
9 A2.1.2 (Updated) table 1, and attachment H updated.

10 And so the first question is those exhibits are in
11 CGAAP, yes?

12 MS. SCOTT: That is correct.

13 MR. SHEPHERD: Can you provide table 1 and attachment
14 H in modified IFRS?

15 MS. SCOTT: We have provided attachment H, which is
16 the revenue requirement work form, in MIFRS. It's
17 attachment AW in the updated attachments.

18 And because the Board Staff has asked us to do that
19 again, there will be another -- under LT1.9 we will be
20 providing it again in the format, which doesn't change the
21 numbers. They just asked for the format to change.

22 MR. SHEPHERD: Okay. And so can you provide us with
23 an explanation, sort of a line-by-line, of the differences
24 between the two? Just, what I would like you to do, if you
25 could, is give us the two sets of information side by side
26 with an explanation of the differences.

27 MS. SCOTT: Of the two revenue deficiencies?

28 MR. SHEPHERD: Yes, the two revenue-requirement work-

g) Please identify all overhead related items (e.g. indirect costs, corporate centre costs) and identify the items that are ineligible and how much overhead in total has been removed from capitalization for ineligible costs.

Guelph Hydro's Response:

Payroll and Operations • Administration Expense • Indirect Labour -Line Crew -Maintenance -Metering -Customer Service -Inspection/Engineering • Employee Benefits • Small Tools • Clothing • Building Maintenance • Insurance • Outside Services – Subcontract • Property Taxes • Supervisory Salaries – Line Supervisors • Supplies/Other • Vehicle Expenses	Stores Burden • Administration Expense • Building Maintenance • Depreciation • Salaries Management • Salaries – Bargaining Unit • Salaries – Temporary Staff • Employee Benefits • Equipment Maintenance • Freight • Insurance • Inventory Adjustment • Licensing Fees • Other • Outside Services • Property Taxes • P.C. Expense • Supplies • Vehicles • Work Order Charges
Fleet Burden • Administration Expense • Building and Operating Costs • Depreciation • Employee Benefits • Equipment Maintenance • Freight • Fuel • Insurance • Licensing • Other	Engineering Burden • Administration Costs • Employee Benefits • Equipment Maintenance • Freight • Memberships • Mini Computer • Other • Outside Services • P.C. Expense • Salary - Bargaining Unit

• Outside Services • Property Taxes • P.C. Expenses • Salary – Bargaining Unit • Salary – Temporary • Supplies • Training • Work Order Charges	• Salary – Management • Salary – Temporary • Supplies • Telephone • Vehicles • Work Order Charges
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The above listing represents Guelph Hydro's 2010 overhead listing prior to the implementation of IFRS. Included in the above listing are the following costs which have been removed since they are not directly attributable to the construction of assets:

- Non-productive time (training costs, safety meetings, adverse weather)
- Property taxes
- Supervisory salaries related to administrative functions
- Insurance
- Stores costs
- Information technology expenses
- Office equipment maintenance
- Freight
- Memberships
- Office supplies

The total overhead removed from capitalization amounted to \$2.7 million in 2010.

h) Please identify the burden rates related to the capitalization of costs of self-constructed assets:

- prior to transition (from the last rebasing application to January 1, 2010), and
- after transition (on or after January 1, 2010).

Guelph Hydro's Response:

Burden		Basis		Applied to	
Payroll		Work Order Payroll		Lines, Metering, Maintenance	
Operations		Work Order Payroll		Lines, Metering, Maintenance	
Payroll		Work Order Payroll		Inspectors, Customer Service	
Operations		Work Order Payroll		Inspectors, Customer Service	
Stores		Stores Issues			
Stores-Engineering		Stores Issues			
Engineering - O&M		Work Order Payroll		O&M Work Orders	
Engineering - Capital		Work Order Payroll		Capital Work Orders	
Engineering - Contracting		Contracting			
Vehicles - LC, IN, CS		Work Order Payroll		Lines, Inspectors, Customer Service	
Vehicles - MA, ME		Work Order Payroll		Maintenance, Metering	

- i) Please identify the overall level of increase in OM&A expense in the test year in relation to a decrease (or increase) in capitalized overhead. Please provide a variance analysis for this increase in OM&A expense for the test year in respect to each of the bridge year and historical years.

Guelph Hydro's Response:

Appendix 2-G OM&A Cost Driver Table

OM&A	Actual 2008	Actual 2009	Actual 2010	Bridge 2011	Test 2012
Opening Balance		\$ 9,788,960	\$ 9,584,309	\$ 9,729,964	\$ 14,517,247
Payroll costs (Note 1)		\$ -	\$ -	\$ 1,115,930	\$ 365,812
Smart meter expenses (Note 2)		\$ -	\$ -	\$ 149,130	\$ 926,286
Energy Conservation Costs (Note 3)		\$ -	\$ -	\$ 190,476	\$ 100,976
Transformer Station operations (Note 4)		\$ -	\$ -	\$ 102,518	\$ 21,086
IFRS (Note 5)				\$ 2,768,431	\$ 109,664
Other OM&A costs (Note 6)		\$ (204,651)	\$ 145,655	\$ 460,798	\$ (429,830)
	\$ 9,788,960				
Closing Balance, prior to the removal of IFRS impact	\$ 9,788,960	\$ 9,584,309	\$ 9,729,964	\$ 14,517,247	\$ 15,611,241
Less: IFRS related items (non-eligible burden previously capitalized)	\$0	\$0	\$0	(\$2,768,431)	(\$2,878,095)
Closing Balance, after the removal of IFRS impact	\$9,788,960	\$9,584,309	\$9,729,964	\$11,748,816	\$12,733,146

See E4/T2/S6 p.1-23 for variance analysis discussions related to the increase in OM&A expenses for the test year in respect to each of the bridge year and historical years.

1 yeah, please include in your analysis the impacts of the
2 changes in the standard.

3 Are you okay with this?

4 MR. MILES: Yes.

5 MS. SEBALJ: So JTC1.10 will be amended accordingly.
6 Mr. Shepherd?

7 **QUESTIONS BY MR. SHEPHERD**

8 MR. SHEPHERD: Thank you.

9 Hi. I'm starting with SEC No. 3, under Issue 2.1.
10 And what we're driving at with this question is that you've
11 changed how much you recover in capital contributions
12 because you've changed how much overhead you capitalize.

13 But I'm trying to confirm that you haven't actually
14 changed how much money you spend to connect customers, that
15 there's no actual changes in expenses here; there's only an
16 accounting change?

17 MR. MILES: That's correct. That's correct.

18 MR. SHEPHERD: So the only impact is a one-side impact
19 that the capital contribution goes down?

20 MR. MILES: No, we wouldn't expect the capital
21 contribution to go down either. We would adjust what we
22 charge for contributions accordingly.

23 MR. SHEPHERD: But your application doesn't reflect
24 that?

25 MR. MILES: I'm not sure what you mean by our
26 application doesn't reflect it.

27 MR. SHEPHERD: Well, in the test year, you forecast
28 that your contributions will go down, right?

1 MR. MILES: That wasn't specifically because of IFRS,
2 though.

3 MR. SHEPHERD: No, sorry, my understanding was that
4 your answer to Energy Probe IR No. 2 was that -- I can get
5 it out if you like, but my understanding was that because
6 you're capitalizing less, the amount your customers will
7 contribute will be lower. Is that not right? Am I
8 misunderstanding that?

9 MR. MILES: Sorry, which question is it again that
10 you're directing us to?

11 MR. SHEPHERD: It was Energy Probe IR No. 2, was what
12 I was originally referring to.

13 MS. BIRCEANU: Original?

14 MR. MILES: Oh, the original IR.

15 MS. BIRCEANU: IR, okay, Energy Probe.

16 MR. SHEPHERD: I think it's in the second answer,
17 so...

18 [Witness panel confers]

19 MR. SHEPHERD: It says here:

20 "The large reduction in contributions and grants
21 from \$4.3 million in 2009 and \$3.4 million in
22 2010 to \$2.7 million in 2011 and \$2.4 million in
23 2012 is the result of conversion to IFRS."

24 And you go on to describe that you capitalize less
25 and, therefore, you get less from the customers. I'm just
26 asking you would do that. Why wouldn't you get the same
27 from the customers?

28 MR. MILES: I'd like to give you an undertaking to

1 come back with an answer on this. We should break this
2 down into more detail.

3 But, conceptually, you know, I want to state that we
4 don't -- just because of an accounting change, we don't
5 expect the level of contributions to change going forward.
6 The reason for -- the bigger reason for the drops in
7 2011/2012 is our overall capital program is decreasing in
8 those years. And, as a result, the contributions are
9 decreasing, as well.

10 We also had a couple of years - I believe it was 2010
11 - where we had some unusually large contributions
12 associated with some data centre customers that we were
13 supplying power to. That was in 2009 and 2010, I believe.
14 There was two separate customers.

15 MR. WITTEMUND: 2008 and '9.

16 MR. MILES: 2008 and '9.

17 MR. SHEPHERD: So you're suggesting this answer may
18 not be correct?

19 MR. MILES: It may not be correct, yeah. I'll give
20 you an undertaking to revisit that.

21 MR. SHEPHERD: Okay. Thank you.

22 MS. SEBALJ: JTC1.26.

23 **UNDERTAKING NO. JTC1.26: TO PROVIDE FURTHER DETAIL IN**
24 **RESPONSE TO ENERGY PROBE IR NO. 2**

25 MR. SHEPHERD: Then our next one is SEC No. 5, which
26 talks about your capital budget template. And if I
27 understand your answer correctly, you don't have a formal
28 template in which you say, Projects must fit in this

Issue 6:

Should the Board grant a generic variance account, for utilities that have rebased under modified IFRS, to mitigate volatility in certain expenses that may arise from the application of IFRS rules? In particular, differences in depreciation or amortization expense caused by changes in estimated useful life of in-service PP&E or intangible assets included in rate base, gains and losses arising from early retirement of in-service assets and differences in pension and post-employment benefit expenses should be considered.

The staff proposal on this issue read as follows:

Staff recommends that no generic variance account be established at this time to mitigate the volatility that may be created by the application of IFRS rules. Utilities that experience, or can demonstrate a likelihood of, significant ongoing volatility can apply to the Board for utility-specific relief.

With one exception, utility commentators did not support staff's proposal, and submitted that a variance account be established in which utilities record differences in the items listed in the issue. The changes in asset useful life and early retirement of assets have impacts on amortization expenses and volatility may be experienced in pension and post-employment benefit expenses. EGD supported staff's proposal.

With respect to changes in asset useful life, the EDA noted distributors will be required to recognize a change in the useful life of an asset for accounting purposes under IFRS. This would lead to a divergence between the rate base and the net book value, which will continue to exist unless and until the rate base values are brought in line with the values in the financial statements at the next rebasing. The EDA submitted that there is a need for an account in order to be able to bring the rate base values in line with the financial statements and enable recovery or refund of the differences.

The EDA also submitted that an account should be established to record any gain or loss that arises from the early retirement of assets as required by IFRS accounting. The EDA stated that utilities have no experience in forecasting the extent of losses arising from early retirement of in-service assets, and most utilities are likely to encounter material difficulties in forecasting the extent of losses.

Hydro One suggested that many utilities will incur premature retirement losses on an ongoing basis after adoption of IFRS that are significant enough to be considered material for regulatory purposes, and that utilities will not be able to forecast premature retirement losses with sufficient precision to justify the inclusion of the losses in forecast revenue requirements.

The CLD submitted that under IFRS, past service costs and actuarial gains or losses likely will be recognized immediately in income. These increases or reductions in costs, which can be material, may never be reflected in rates if not captured in a variance account. The CLD supports the establishment of a variance account to record significant changes in post retirement benefit costs relative to the costs in rates. The EDA concurred and noted that the IASB is in the final stages of issuing an amendment to IAS 19 that will require all entities to immediately recognize actuarial gains and losses.

No ratepayer representative supported the creation of a variance account for these items.

The Board is not persuaded that a generic account is necessary. The Board is not aware of any reliable data at this time to satisfy the Board that the adoption of IFRS accounting changes will apply to all utilities in a similar or consistent manner, or that the adoption that will cause material impacts for all utilities due to ongoing increase in volatility. In addition, the Board believes that it will be difficult to distinguish the differences arising from IFRS accounting policy changes from other differences, and this difficulty will increase with increasing time post-transition.

The Board notes that the deferral account provided for in Issue 2 will give utilities relief during the IRM period immediately following the transition to IFRS for rate base related items. At the first cost of service application after the transition, a utility will be expected to provide a forecast of asset useful lives, and gains and losses from retirements, as part of its application. This forecast will be reviewed by the Board and the likelihood of large variances from the forecast can be assessed. Utilities can apply to the Board for a utility-specific variance account if they can demonstrate the probability of significant ongoing volatility.

With respect to P&OPEB items, the Board is not persuaded that a generic account is necessary. It is not clear that the impact of the transition to IFRS on P&OPEB items

will be consistent among Ontario utilities. Individual utilities that can demonstrate the likelihood of large variances can seek an individual variance account from the Board.

If it becomes apparent over time that utilities are generally experiencing material, unpredictable variances in these items, the Board will consider solutions in its development of rate-setting mechanisms.