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EB-2014-0073

Ontario

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Festival Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

BOARD STAFF

COMPENDIUM OF DOCUMENTS

November 13, 2014

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2012-0124

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Festival Hydro Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2013.

BEFORE: Marika Hare
Presiding Member

DECISION AND ORDER
April 4, 2013

Introduction

Festival Hydro Inc. ("Festival Hydro"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on August 27, 2012 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Festival Hydro charges for electricity distribution, to be effective May 1, 2013.

Festival Hydro is one of 77 electricity distributors in Ontario regulated by the Board. The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "IR Report"), issued on July 14, 2008, established a three year plan for 3rd generation incentive regulation mechanism ("IRM") (i.e., rebasing plus three years). In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the IRM plan until such time as the RRFE policy initiatives have been substantially completed. In a letter dated October 18, 2012, the Board stated its expectation that the three rate setting methods set out in the *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* would be available for the 2014 rate year.

As part of the plan, Festival Hydro is one of the electricity distributors that will have its rates adjusted for 2013 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008 (the "Supplemental Report"), and *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (collectively the "Reports"). Among other things, the Reports provide the relevant guidelines for 2013 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On June 28, 2012, the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

In addition to the mechanistic adjustments included in the IRM plan, Festival Hydro sought approval for an incremental capital module, adjustments to its revenue-to-cost ratios and deferred disposition of its Lost Revenue Adjustment Mechanism ("LRAM").

Notice of Festival Hydro's rate application was given through newspaper publication in Festival Hydro's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Notice of Application indicated that intervenors could be eligible for cost awards with respect to Festival Hydro's proposed incremental capital module and proposed revenue-to-cost ratio adjustments. The Vulnerable Energy Consumers Coalition ("VECC") and the School Energy Coalition ("SEC") applied and were granted intervenor status in this proceeding. The Board granted VECC and SEC eligibility for cost awards in regards to Festival Hydro's request for an incremental capital module and revenue-to-cost ratio adjustments. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Rural or Remote Electricity Rate Protection Charge;
- Wholesale Market Service Rate;
- Smart Metering Entity Charge;
- MicroFIT Service Charge;
- Revenue-to-Cost Ratio Adjustments;
- Shared Tax Savings Adjustments;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Account Balances;
- Review of Lost Revenue Adjustment Mechanism and
- Incremental Capital Module ("ICM")

Price Cap Index Adjustment

As outlined in the Reports, distribution rates under the IRM are to be adjusted by a price escalator, less a productivity factor of 0.72% and a stretch factor.

On March 21, 2013, the Board announced a price escalator of 1.6% for those distributors under IRM that have a rate year commencing May 1, 2013.

The stretch factors are assigned to distributors based on the results of two benchmarking evaluations to divide the Ontario industry into three efficiency cohorts. In its letter to Licensed Electricity Distributors dated November 28, 2012 the Board assigned Festival Hydro to efficiency cohort 1, being the most efficient group, and a resulting cohort specific stretch factor of 0.2%.

The Board therefore has determined, on that basis, that the resulting price cap index adjustment is 0.68% (i.e. 1.60% - (0.72% + 0.20%)). The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across customer classes.

The price cap index adjustment does not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charge; and
- Retail Service Charges.

Rural or Remote Electricity Rate Protection Charge

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Rural or Remote Electricity Rate Protection ("RRRP") used by rate regulated distributors to bill their customers shall be $0.0012 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this RRRP charge.

Wholesale Market Service Rate

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this WMS rate.

Smart Metering Entity Charge

On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers for those distributors identified in the Board's annual *Yearbook of Electricity Distributors*. This charge will be in effect from May 1, 2013 to October 31, 2018. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects this Smart Metering Entity charge.

MicroFIT Service Charge

On September 20, 2012, the Board issued a letter advising that the default province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator Service Classification was to be updated to $5.40 per month effective with the implementation of electricity distributors' 2013 rates applications. The draft Tariff of Rates and Charges flowing from this Decision and Order reflects the new default microFIT service charge.

Revenue-to-Cost Ratio Adjustments

Revenue-to-cost ratios measure the relationship between the revenues expected from a class of customers and the level of costs allocated to that class. The Board has established target ratio ranges (the "Target Ranges") for Ontario electricity distributors in its report *Application of Cost Allocation for Electricity Distributors*, dated November 28, 2007 and in its updated report *Review of Electricity Distribution Cost Allocation Policy,* dated March 31, 2011.

Pursuant to the Board's decision in the Festival Hydro's 2010 cost of service application EB-2009-0263 Festival Hydro proposed to increase the revenue-to-cost ratio for the residential class in the Hensall service territory.

The additional revenues from these adjustments would be used to reduce the revenue-to-cost ratio for the residential class in Festival Hydro's main territory.

The table below outlines the proposed revenue-to-cost ratios.

Rate Class	Current 2012 Ratio	Proposed 2013 Ratio
Residential	106.66	106.47
Residential - Hensall	99.00	106.27
General Service Less Than 50 kW	112.03	112.03
General Service 50 to 999 kW	81.31	81.31
Large User	112.03	112.03

Street Lighting	70.00	70.00
Sentinel Lighting	70.00	70.00
Unmetered Scattered Load	120.00	120.00

VECC and SEC did not comment on the proposed revenue-to-cost ratio adjustments. Board staff took no issue with Festival Hydro's proposal.

The Board agrees that the proposed revenue-to-cost ratios are consistent with the decision arising from the 2010 cost of service proceeding and therefore approves the revenue-to-cost ratios as filed.

Shared Tax Savings Adjustments

In its Supplemental Report, the Board determined that a 50/50 sharing of the impact of currently known legislated tax changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate.

The calculated annual tax reduction will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers over a 12-month period, through a volumetric rate rider using annualized consumption by customer class underlying the Board-approved base rates.

Festival Hydro's application identified a total tax savings of $170,671 resulting in a shared amount of $85,336 to be refunded to rate payers.

The Board approves the disposition of the shared tax savings of $85,336 over a one year period (i.e. May 1, 2013 to April 30, 2014) and the associated rate riders for all customer rate classes.

Retail Transmission Service Rates ("RTSRs")

Electricity distributors are charged for transmission costs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e. variance Accounts

1584 and 1586).

On June 22, 2012 the Board issued revision 3.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2013. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Ontario Uniform Transmission Rates ("UTRs") levels and the revenues generated under existing RTSRs. Similarly, embedded distributors whose host is Hydro One Networks Inc. ("Hydro One") should adjust their RTSRs to reflect any changes in Hydro One's Sub-Transmission class RTSRs. The objective of resetting the rates is to minimize the prospective balances in Accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributors' specific RTSRs, Board staff provided a filing module.

Festival Hydro is a partially embedded distributor whose host is Hydro One.

On December 20, 2012 the Board issued its Rate Order for Hydro One Transmission (EB-2012-0031) which adjusted the UTRs effective January 1, 2013, as shown in the following table:

2013 Uniform Transmission Rates

Network Service Rate	$3.63 per kW
Connection Service Rates	
Line Connection Service Rate	$0.75 per kW
Transformation Connection Service Rate	$1.85 per kW

The Board also approved new rates for Hydro One Sub-Transmission class RTSRs effective January 1, 2013 (EB-2012-0136), as shown in the following table.

2013 Sub-Transmission RTSRs

Network Service Rate	$3.18 per kW
Connection Service Rates	
Line Connection Service Rate	$0.70 per kW
Transformation Connection Service Rate	$1.63 per kW

The Board finds that these 2013 UTRs and Sub-Transmission class RTSRs are to be incorporated into the filing module.

Review and Disposition of Group 1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report Initiative* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Festival Hydro's 2011 actual year-end total balance for Group 1 Accounts including interest projected to April 30, 2013 is a debit of $297,020. This amount results in a total debit claim of $0.0005 per kWh, which does not exceed the preset disposition threshold.

In its submission, Board staff noted that the principal amounts to be disposed as of December 31, 2011 reconcile with the amounts reported as part of the *Reporting and Record-keeping Requirements* ("RRR").

The Board therefore finds that no disposition is required at this time.

Review and Disposition of Lost Revenue Adjustment Mechanism ("LRAM")

The Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (the "CDM Guidelines") issued on April 26, 2012 outline the information that is required when filing an application for LRAM.

In its application, Festival Hydro noted that the LRAMVA amount owing based on OPA 2011 draft Annual Results Report is $41,826. Festival Hydro submitted that it did not deem this amount to be significant and will defer its LRAMVA claim to its 2014 cost of service filing.

Board staff and intervenors did not make a submission on this matter.

The Board agrees with Festival Hydro that the LRAMVA amount should be deferred to a future rate application.

Incremental Capital Module ("ICM")

Festival Hydro proposed to recover, through an ICM, the revenue requirement impact of the incremental capital cost of $15,863,113 associated with the construction of a new municipal transformer ("TS") station in the city of Stratford.

Festival Hydro proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery (i.e. $672,412) on the basis of distribution revenue. Festival Hydro proposed to recover these amounts by means of fixed and variable rate riders that would be in place until such time that Festival Hydro files its next rebasing application (scheduled for 2014 rates).

The IR Report requires that incremental capital expenditures satisfy the eligibility criteria of materiality, need and prudence in order to be considered for recovery prior to rebasing. Applicants must demonstrate that amounts exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor, must be clearly non-discretionary and the amounts must be outside of the base upon which rates were derived.

(i) Materiality

Festival Hydro is claiming total incremental capital of $7,777,903. This represents half of the total cost of the TS ($15,863,113) plus the total non-discretionary capital budget ($3,489,000) less the threshold calculation of $3,642,654.

Both VECC and SEC submitted that the Board-defined materiality threshold has been met.

Board staff submitted that the total eligible incremental capital calculated in accordance with recent ICM Board decisions would be $15,709,459 (i.e,.$15,863,113 (the cost of the transformer) plus $3,489,000 (the remaining non-discretionary capital forecast for 2013) minus the materiality threshold of $3,642,654). Based on this calculation, $15,709,459 is the total amount of the TS that Festival Hydro is eligible to base its revenue requirement calculation on. Since Festival Hydro is scheduled to rebase one year after the ICM, the half year rule should apply. Therefore, the amount used in the model should be $7,854,730. Board staff estimates that Festival Hydro has understated the revenue requirement impact by approximately $6,000.

In its response, Festival Hydro agreed with Board staff and updated the ICM Workform and Rate Generator Model accordingly to reflect this change.

(ii) Project Need and Prudence

Festival Hydro indicated that the incremental capital expenditures are related to the construction of the new TS scheduled to be in-service by April 30, 2013. The project is forecasted to be 65% complete by the end of 2012 and is on schedule to meet its in-service date of April 30, 2013. The TS is being constructed to alleviate a potential overload condition at the existing Hydro One owned Stratford TS that provides the sole supply of electricity to the City of Stratford and the surrounding area. In its application, Festival Hydro stated that it will continue to exceed its assigned capacity on a regular basis until the new municipal TS is constructed. Festival Hydro stated that if load continues to increase as most recently forecasted, by 2014 a failure of a single major component at the existing Stratford TS during peak loads could result in rotating blackouts for the City of Stratford and surrounding area. As load in Stratford continues to grow, the likelihood of rotating blackouts will also increase. In addition to adding capacity, the new municipal transformer will eliminate low voltage issues at the end of the longest feeders and significantly improve reliability for all customers in Stratford.

In 2009, Festival Hydro considered four options and selected the one with the lowest net present value and the one that addressed its capacity, voltage and reliability issues. In response to interrogatories, Festival Hydro noted that it had approached Hydro One on several occasions to discuss potential cost sharing arrangements. However, Hydro One indicated that it did not foresee sufficient growth within its service area that could not be accommodated from the existing Stratford TS or other existing Hydro One delivery points. Therefore, Festival Hydro stated that Hydro One did not feel it had a need for the additional capacity provided from the new TS.

In 2011, Festival Hydro retained the services of Costello & Associates to assist with the conceptual design, planning review and technical details of the new TS. The final report from Costello & Associates concluded that the load forecast prepared by Festival Hydro was consistent with typical utility practices, that a new TS is required to meet load growth and that Festival Hydro should design, construct and operate a new TS.

Festival Hydro noted that if the incremental capital rate riders were not approved, it would cause further carrying costs to Festival Hydro in terms of additional interest expense. In addition, Festival Hydro stated that customers will receive immediate benefit from the new TS which supports matching Festival Hydro's cost recovery to commence during the same period.

SEC submitted that it was satisfied with the materiality and prudence of the ICM. However, SEC noted that while the updated 2011 load forecast would appear to delay the necessity of the project for a year as it related to capacity, SEC is satisfied with Festival Hydro's justification that the costs associated with halting construction of the TS and the reliability concerns of the delay, would on balance not be in the best interest of ratepayers.

VECC submitted that Festival Hydro has provided adequate evidence that its proposal represents the most cost effective option and that Festival Hydro's explanations regarding the possibility of unreliable supply in the near term resulting from a small increase in load are reasonable.

In its submission, Board staff took no issue with the need and prudence regarding the construction of the new TS. However, Board staff requested clarification regarding the establishment of the in-service date of April 30, 2013. Given the updated 2011 load forecast, Board staff questioned why Festival Hydro maintained the same in-service date target given that the loading issues on the existing TS appeared not to be as imminent as indicated by the older study.

In its response, Festival Hydro noted that the maximum permissible load that can be reliably supplied by the existing TS is 85 MW. The 2011 updated load forecast estimated peak load in 2013 and 2014 to be 81.7 MW and 84.3 MW respectively. Festival Hydro stated that several industrial customers in Stratford had reduced their load during the 2009 and 2011 economic slowdown but were anticipating a return to historic load levels once the economic conditions improved. Festival Hydro notes that the 3.3 MW margin in 2013 would be quickly used up by one or two industrial customers resuming normal load, or by a few mid-sized commercial customers developing in Stratford. In the event of the loss of one major element (i.e: bus breaker, station transformer, or transmission circuit) during peak periods, any load that is in excess of the 85 MW would be subject to rotating blackouts.

Board Findings

The Board accepts the evidence that a new transformer station is needed and is a non-discretionary expense to come into service in 2013. The Board is further persuaded by the evidence that the project evaluation was done thoroughly and the resulting solution is prudent. The annual revenue requirement impact arising from the proposed cost of $7,854,730 is therefore approved for recovery through rate riders to be included on Festival Hydro's Tariff of Rates and Charges for 2013 rates and until the effective date of its next cost of service rate order.

Incremental Revenue Requirement Calculation and Recovery

Festival Hydro used the cost of capital parameters underpinning its last cost of service application. Board staff submits that this is consistent with Filing Requirements.

Festival Hydro used a 60% debt and 40% equity deemed capital structure when calculating the revenue requirement associated with the incremental capital expenditures.

Festival Hydro proposed to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery (i.e. $679,039) on the basis of a combined fixed and variable rate riders. The rate riders would be in place until such time that Festival Hydro files its next cost of service rate application (i.e. one year).

In its submission, Board staff noted that the Board previously approved in the case of Guelph Hydro (EB-2010-0130), Oakville Hydro (EB-2010-0104) and Centre Wellington (EB-2011-0160) an allocation of the revenue requirement on the basis of distribution revenue and the recovery of the incremental annual revenue requirement amount by means of a variable rate rider only.

In its response, Festival Hydro noted that it preferred its proposal of a monthly fixed service charge and distribution volumetric charge and requested that the rate riders be in place until the effective date of the next cost of service-based rate order.

The Board agrees with Festival Hydro that the incremental revenue requirement should be allocated on a combined fixed and variable split. The Board notes that each rate class contains customers at different consumption levels and a combined fixed and variable split will ensure consistent bill impact within each rate class.

Rate Model

With this Decision, the Board is providing Festival Hydro with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board has reviewed the entries in the rate model to ensure that they are in accordance with the 2012 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

THE BOARD ORDERS THAT:

1. Festival Hydro's new distribution rates shall be effective May 1, 2013.

2. Festival Hydro shall review the draft Tariff of Rates and Charges set out in Appendix A. Festival Hydro shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information within **7 days** of the date of issuance of this Decision and Order.

3. If the Board does not receive a submission from Festival Hydro to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the draft Tariff of Rates and Charges set out in Appendix A of this Decision and Order will become final, effective May 1, 2013, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2013. Festival Hydro shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. If the Board receives a submission from Festival Hydro to the effect that inaccuracies were found or information was missing pursuant to item 2 of this Decision and Order, the Board will consider the submission of Festival Hydro and will issue a final Tariff of Rates and Charges.

Cost Awards

The Board will issue a separate decision on cost awards once the following steps are completed:

1. VECC and SEC shall submit their cost claims no later than **7 days** from the date of issuance of the final Rate Order.

2. Festival Hydro shall file with the Board and forward to VECC and SEC any objections to the claimed costs within **21 days** from the date of issuance of the final Rate Order.

3. VECC and SEC shall file with the Board and forward to Festival Hydro any responses to any objections for cost claims within **28 days** from the date of issuance of the final Rate Order.

4. Festival Hydro shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote file number **EB-2012-0124,** be made through the Board's web portal at, https://www.pes.ontarioenergyboard.ca/eservice// and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to BoardSec@ontarioenergyboard.ca. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 2 paper copies.

DATED at Toronto, April 4, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

To Decision and Order

Draft Tariff of Rates and Charges

Board File No: EB-2012-0124

DATED: April 4, 2013

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0124

RESIDENTIAL SERVICE CLASSIFICATION

A customer is classed as residential when all the following conditions are met:
(a) the property is zoned strictly residential by the local municipality,
(b) the account is created and maintained in the customer's name,
(c) the building is used for dwelling purposes.
Exceptions may be made for properties zoned for farming use, under the following conditions:
(a) the principal use of the service is for the residence,
(b) the service size is 200 amperes or less, and the service is 120/240 volt single phase.
Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

FOR ALL SERVICE AREAS EXCEPT HENSALL

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	14.99
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	1.00
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014	$	0.20
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	2.79
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0167
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kWh	(0.0009)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) / Shared Savings Mechanism (SSM) Recovery - effective until April 30, 2014	$/kWh	0.0006
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kWh	0.0011
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0124

FOR HENSALL SERVICE AREA

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	14.99
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	0.92
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014	$	0.20
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	2.79
Distribution Volumetric Rate	$/kWh	0.0162
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) / Shared Savings Mechanism (SSM) Recovery - effective until April 30, 2014	$/kWh	0.0006
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kWh	(0.0003)
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kWh	0.0010
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0124

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose peak demand is less than 50 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Customers who are classed as General Service but consider themselves eligible to be classed as Residential must provide Festival Hydro with a copy of their tax assessment, which clearly demonstrates the zoning is for residential use only. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	29.08
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	1.93
Rate Rider for Disposition of Residual Historical Smart Meter Costs – effective until April 30, 2014	$	2.38
Rate Rider for Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service-based rate order	$	4.72
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0147
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kWh	(0.0010)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) / Shared Savings Mechanism (SSM) Recovery - effective until April 30, 2014	$/kWh	0.0001
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kWh	(0.0002)
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kWh	0.0010
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0124

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to a non residential account whose peak demand is equal to or greater than 50 kW but less than 5,000 kW based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	224.76
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	14.89
Distribution Volumetric Rate	$/kW	2.3045
Low Voltage Service Rate	$/kW	0.0689
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kW	(0.3508)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) / Shared Savings Mechanism (SSM) Recovery - effective until April 30, 2014	$/kW	0.0389
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kW	(0.0254)
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kW	0.1527
Retail Transmission Rate - Network Service Rate	$/kW	2.5104
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.7793
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.6664
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	1.9506

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0124

LARGE USE SERVICE CLASSIFICATION

This classification refers to non-residential accounts whose monthly peak demand is equal to or greater than 5,000 kW, based on the process for and frequency for reclassification as outlined in Section 2.5 of the Distribution System Code. For a new customer without prior billing history, the kW peak demand will be estimated by Festival Hydro to determine the proper rate classification. Further servicing details are available in Festival Hydro's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	10,749.52
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	712.23
Distribution Volumetric Rate	$/kW	0.9975
Low Voltage Service Rate	$/kW	0.0801
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kW	(0.4507)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) / Shared Savings Mechanism (SSM) Recovery - effective until April 30, 2014	$/kW	0.1910
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kW	(0.0250)
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kW	0.0661
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	2.9524
Retail Transmission Rate - Line and Transformation Connection Service Rate - Interval Metered	$/kW	2.2307

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0124

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian Cross-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	12.88
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	0.85
Distribution Volumetric Rate	$/kWh	0.0127
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kWh	(0.0008)
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kWh	(0.0004)
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kWh	0.0008
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0124

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.03
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	0.13
Distribution Volumetric Rate	$/kW	10.6862
Low Voltage Service Rate	$/kW	0.0504
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kW	(0.3881)
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kW	(0.1138)
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kW	0.7080
Retail Transmission Rate - Network Service Rate	$/kW	1.9029
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.4044

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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EB-2012-0124

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. If connected to the municipal or the Province of Ontario street lighting system, decorative lighting and tree lighting services will be treated as a Street Lighting class of service. Decorative or tree lighting connected to Festival Hydro Inc.'s distribution system will be treated as a General Service Less Than 50 kW class customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.09
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$	0.07
Distribution Volumetric Rate	$/kW	4.9532
Low Voltage Service Rate	$/kW	0.0494
Rate Rider for Disposition of Deferral/Variance Account (2010) – effective until April 30, 2014	$/kW	(0.2751)
Rate Rider for Application of Tax Change - effective until April 30, 2014	$/kW	(0.0984)
Rate Rider for Recover of Incremental Capital (2013) - effective until April 30, 2014	$/kW	0.3282
Retail Transmission Rate - Network Service Rate	$/kW	1.8933
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.3756

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0124

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0124

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$	0.60
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	1.00

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Orderof the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges forthe Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Income Tax Letter	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment – per month	%	1.50
Late Payment – per annum	%	19.66
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect Charge – At Meter – After Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00

Service Call – Customer-owned Equipment – During Regular Hours	$	30.00
Service call – after regular hours	$	165.00
Temporary Service – Install & remove – overhead – no transformer	$	500.00
Temporary Service – Install & remove – underground – no transformer	$	300.00
Temporary Service Install & Remove – Overhead – With Transformer	$	1,000.00
Specific Charge for Access to the Power Poles - $/pole/year	$	22.35

Festival Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0124

RETAIL SERVICE CHARGES (if applicable)

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It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0307
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0176
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0204
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0075

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2013 ICM APPLICATION; ATT. 1 - 2013 INCREMENTAL CAPITAL SUPP. DOCUMENTS

EB-2012-0124

11. FHI BOARD REPORT TS DEC. OCT. 2010

MEMORANDUM

October 1, 2010

To: Chair MacDougald & Board Members

From: J. P. Vanderbaan, Vice-President, Engineering and Operations
D. Reece, Secretary Treasurer
K. McCann, Financial & Regulatory Analyst

Re: Second Transformer Station for Stratford – Ownership Recommendation

As previously reported, the existing Transformer Station in Stratford is reaching capacity, and the new data centre load plus projected load growth will put the station beyond the recommended rating (LTR). We have reviewed capacity options with Hydro One, and the most prudent option is to construct a second TS to supply the load growth in Stratford. The new TS would be a DESN (dual element spot network) design with an initial install of one transformer and 4 feeders with the space to install a second transformer and 4 additional feeders.

For the construction of the new TS, there are three options available to us:

1. Hydro One designs, builds, owns, and maintains the new TS (as they currently do with the existing stations in Stratford and St Marys).
2. Festival Hydro designs and builds the station (to meet Hydro One specifications) then turns the asset over to Hydro One who will then assume ownership and maintenance obligations. (This option has never been pursued to date.)
3. Festival Hydro designs, builds, owns, and maintains the new TS.

The second option has not been pursued to date primarily due to technical challenges constructing a station to meet Hydro One's requirements without having them fully involved in the design and installation process (overall minimal cost savings). Therefore, only options 1 and 3 were examined in greater depth.

FHI entered into an agreement with Hydro One for them to prepare a Class B estimate for the station cost. The cost to prepare the Class B estimate is $120,000, which is rolled into the total station cost if Hydro One builds the station, or becomes payable by FHI in 2010 if FHI builds the station. The Class B estimate was received in June with subsequent meetings with Hydro One in July and August to clarify some of the financial information.

The estimated cost for Hydro One to build the station is $17.3M plus an additional $1M for the 230 kV connection, plus the cost of land (including environmental assessment) which is estimated to be around $1M.

In addition to preparing the cost estimate, Hydro One provided a projection of the capital contribution from FHI required based on three load forecasts (low, medium, and high). The incremental revenue associated with the new load is used to offset the capital and OM&A

costs. For the low load forecast, a contribution of $16.3M would be required, for the medium load forecast, a contribution of $13.8M would be required, and for the high load forecast, a contribution of $11.7M would be required. A similar process was done for the 230 kV line connection cost, and the contribution required would be $162,000 for the low load forecast and $0 for the medium and high load forecast. The cost for the land of $1M is over and above the capital contribution amounts.

The Class B estimate from Hydro One included documentation of the preliminary design outlining major components, costing, and cash flow. This information was used to generate an RFQ which was issued to three vendors who had recent experience constructing similar stations in Ontario. Two of the vendors [redacted] both provided pricing at the $8M mark, with the third [redacted] coming in unreasonably low at $4M so we have excluded that price from the analysis. (Note: The RFQ was issued to obtain pricing only, and not to award a turn-key project to a vendor. Any contracts needed going forward will follow the normal FHI RFP process including Board approval as required.)

Costing for station monitoring, routine maintenance, unplanned repairs, and other operating expenses were also obtained by contacting vendors and other utilities that own transformer stations. Generally, O&M costs are minimal during the first ten years, then increasing as equipment ages. A 25 year forecast of OM&A costs (including property tax and insurance) was prepared. (For the Hydro One build and own option, the forecast of their OM&A costs is included in the capital contribution calculation.)

Using the load forecast, capital cost, and OM&A costs, a financial model was created to evaluate the overall impact of the Hydro One build and own option (with FHI providing a large capital contribution) to the FHI build and own option.

A summary of the financial impact is summarized below.

<u>Net Present Value Calculation Comparing the Option 1 & 3</u>

Two tables have been attached to this write-up that highlight the cash flows expected under the options to have Hydro One build, own, and maintain the TS or to build, own and maintain the TS ourselves. The attachments indicate that the NPV of the future expected cash flows for FHI to build the TS ourselves ($4,435,297) would be more beneficial versus having Hydro One build it ($4,855,798).

<u>Impact on Distribution Rates</u>

Festival Hydro's next cost of service rate application will be filed effective May 1, 2014 and FHI has received verbal confirmation from Scott Stoll that this is the best strategy in relation to timing of the rate application and inclusion of the TS in rates. Assuming the new TS is in-service by mid-2013, the full net book value of the TS asset should be eligible to be included in our 2014 rate base.

To determine the impact the new TS would have on existing rates, Festival Hydro updated the 2010 rate model overlaying the impact of the new TS station with its related revenues and costs *(assuming Festival Hydro would build and own; not Hydro One.)* Overall, we would expect distribution rates to increase by 12.5%. Offsetting this increase would be a reduction of $355,000 in Network Connection charges, resulting in a net distribution rate impact of 9.0%.

The table below illustrates the impact to our 2010 rate model. The $9.4 million increased rate base would allow an increase of $305,000 for deemed interest and $369,000 for deemed ROE for a total of $675,000. Since the project is being fully funded by a $9.7 million loan, $528,000 of this amount would be required to fund the interest on the loan.

The table also shows the total bill impact to an 800 kWh residential customer. The TS would cause an overall bill increase of 3.8% over the 2009 distribution rates, compared to a 1.2% on the actual 2010 rate increase.

TS Station - Impact on Rates

2010 Original Revenue Requirement			$	10,288,194
2010 Rate Base:	Before TS	After TS		
Average Assets	40,127,578	49,506,238		
Deemed Interest (60% @5.44%)	1,310,088	1,615,686		305,598
Deemed ROE (40% @9.85%)	1,581,026	1,950,546		369,520
	2,891,114	3,566,232		
Additional O& M costs				234,434
Additional depreciation				214,115
Additional income taxes				158,278
Revised 2010 Revenue Requirement			$	11,570,139
Increase in Revenue requirement				1,281,945
% increase in distribution rates				12.5%
Offset from reduced Network connection charges			$	(354,948)
Revised distribution rate increase******				9.0%

Note: the network charge is a separte charge on the bill, so the distribution charge will in fact go up by 12.5% and the network charge will decline. The above illustrates the impact if all this change went through the distribution charge.

Impact on 800 kW residential customer (total bill):

May 1, 2009 Total Bill	101.18	
May 1, 2010 Total Bill	102.35	
Increase effective May 1, 2010	1.17	1.2%
May 1, 2009 Total Bill	101.18	
May 1, 2010 Total Bill with TS impact	104.99	
Increase with TS impact	3.81	3.8%

Overall, the least impact to our customers is the Festival Hydro build and own option. Additionally, by controlling the design and build of the station, FHI can have better cost containment and schedule the installation of feeders to coincide with load requirements. To ensure this project proceeds smoothly, the costing of the FHI option includes the hire of a full-time engineer starting July 1, 2011 and migrating into a new role in 2014 as part of the overall company succession plan.

Recommendation:
Festival Hydro builds and owns the new transformer station with a projected in-service date for the new station to be targeted for July 1, 2013. The project will commence with an agreement with the City for the purchase of the required property so that the environmental assessment and soil testing can commence in early 2011, and FHI will complete the payment to Hydro One before December 31, 2010 for the preparation of the Class B estimate. Future milestones involving purchases above $30,000 (such as completing the land purchase, hiring consultants and contractors, ordering major components, hiring a new engineer, etc.) will follow the normal Board approval process.

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Festival Hydro Inc.

187 Erie Street, Stratford
P.O. Box 397, Stratford
Ontario, N5A 6T5
Telephone: 519-271-4700
Toll-Free: 1-866-444-9370
Fax: 519-271-7204
www.festivalhydro.com

January 4, 2013

BY COURIER

Ms. Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street, 26th Floor, P.O. Box 2319
TORONTO, ON M4P 1E4

Re: Festival Hydro Inc. 2014 Cost of Service Application Deferral Request

Dear Ms. Walli:

Festival Hydro Inc. (Festival) is scheduled to file a Cost of service application for rates effective May 1, 2014 as noted in the Board's letter dated December 11, 2012. Festival respectfully requests a departure from this rebasing schedule and requests a cost of service application be filed by Festival for rates effective January 1, 2015.

Festival highlights that this letter serves two purposes. One to request a transition from May 1 rates to January 1 rates, and secondly to request a deferral from a 2014 cost of service application to a 2015 application based on the report cited below.

Festival notes that in the Board report "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" dated October 18, 2012, page 69 indicates that:

> *"For distributors scheduled to rebased for 2014 and planning to seek the Board's approval for January 1 rates, there will be two options available……(2) Delay rebasing by one year – rebase for January 1, 2015 rates, in which case the application will be filed using the Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements, and the total term will be 5 years."*

Festival is making the deferral request under this highlighted option in the report.

Festival performed significant analysis in determining if a request at this time was feasible. Festival considered the following:

- Benefit of having rate changes aligned with our fiscal year
- Financial impact of rebasing May 1, 2014 versus January 1, 2015
- Approval or disapproval of our ICM application as we may not get a final response on this until as late as April 2013
- A January 1, 2015 application approval would also require one additional third generation IRM filing for an eight month period (May 1, 2014 – January 1, 2015)

Festival's believes the benefits of moving to a rate year that matches our fiscal year are substantial in that this matches distribution rates with the expenses upon which the rates are granted.

Festival performed a financial analysis on the feasibility of the deferral and noted that an eight month deferral would not negatively impact our financial position by any significant amount. Festival also notes that we are not earning an unacceptable return on equity currently. Festival advises that its actual rate of return on average equity for 2011, the most recent year for which complete data is available, was 11.71%, and falls within the trigger of 300 basis points from the Board-approved return of 9.85%. Festival estimates its 2012 rate of return on average equity to be 9.08%, also within the trigger of 300 basis points from the Board-approved return.

Festival also notes that this deferral request is contingent on Board approval of our incremental capital rate rider request in our 2013 IRM application, as our financial analysis performed in making the deferral request indicates that the deferral would not be feasible should the ICM rate rider not be approved. In addition, Festival's deferral decision is based on an ICM rate rider being approved effective May 1, 2013, to be in effect until the effective date of the next cost of service rate rider. Festival has at this point answered all concerns of OEB staff and interveners in regards to our ICM application and believes that the application is supported by Board staff and our interveners. As such Festival feels it is reasonable to move forward with our COS deferral request.

It would be Festival's intention to submit a third generation IRM rate application for rates effective May 1, 2014, with Board approval to defer our cost of service application to January 1, 2015. This amounts to only an eight-month deferral.

In relation to the other considerations the Board will have in deciding on this deferral beyond Festival's financial position, Festival feels our performance with respect to system reliability indicators and electricity service quality requirements as reported to the Board are satisfactory.

In summary, Festival requests deferral of its rebasing due to the fact that it meets the Board requirements to request such deferral and there is a desire to have distribution rates match the fiscal year of the utility. Given the release of the Renewed Regulatory Framework, Festival has been given the option of deferring a January 1, 2014 cost of service application to January 1, 2015.

Should you require any further information or clarification please contact me.

Respectfully submitted,

J. Vanderbaan, Chief Operating Officer

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ICM Rate Rider ACCOUNT # 1508 - Continuity Schedule (REVISED to agree to 2 staff 8)

	2013	2014	Jan 1, 2015 transfer
Opening, Jan 1	0	15,058,931	14,710,516
TS O & M Expenses	104,816	140,000	-244,816
Interest	17,623	217,469	-235,093
Transfer in from CWIP	15,311,782	0	-15,311,782
Depreciation & Amortization	28,137	337,647	-365,784
Accumulated Depreciation & Amort	-28,137	-337,647	365,784
Less ICM Rate Rider Recovery	-375,291	-705,884	1,081,174
Ending Bal, Dec 31	15,058,931	14,710,516	-0

Entry required for Jan 1, 2015 disposition:				
		USOA		
TS Land	DR	1805	913,474.39	
TS capital	DR	1815	13,961,839.83	
CCRA agreement	DR	1609	436,468.00	
Interest Income	DR	4405	235,092.89	
Distribution Revenue	CR	4080		1,081,174.36
Depn Exp	DR	5705	346,870.00	
Amort Exp	DR	5715	18,914.00	
Accum Depn	CR	2105		346,870.00
Accum Amort	CR	2120		18,914.00
TS O & M Expenses	DR	5015	244,815.74	
ICM Variance Acct	CR	1508		14,710,516.49
			16,157,474.85	16,157,474.85
Transfer back to fixed asssets1805,1815,1609 (gross)			15,311,782.22	
Less Accuimulated Depreciation/Amortization			-365,784.00	
Net book value upon transfer , Jan 1, 2015			14,945,998.22	

32. 2. OEB STAFF 9

Ref: E2/T2/S1, p. 14 – Stratford Transformer Station – Permanent Bypass Agreement

On page 14, Festival Hydro states that:

As a result of Festival constructing a new transformer station, Festival entered into a Permanent Bypass Compensation Agreement with Hydro One for the purpose of addressing the bypass compensation payable by Festival in accordance with Section 6.7.7 of the Transmission System Code. The agreement allows for a Bypass Capacity from the existing Hydro One station at an estimate 20 MW with a Bypass Compensation Estimate amount of $1,230,026.

The cost of this Bypass agreement was not part of the original construction budget used for the ICM rate rider. However, the cost is a component of the overall cost of the transformer station. Festival commenced the bypass on December 1, 2013 upon energizing its first customer for the new TS. Currently (Feb 2014), there is about 12 MW being bypassed with a plan to migrate close to the 20 MW during 2014.

a) Please confirm that Festival is including an incremental $1.23M in rate base for a permanent Bypass Agreement with HONI.
b) Please explain why the cost of the Bypass agreement was not part of the ICM application for the 2013 rate year.
c) Please provide a revised assessment that shows that the cost of the new transformer station, including the cost of the bypass agreement, was still the best option.
d) Has the amount of $1.23M been paid in full to HONI as a one-time cost?
i. If so, provide the date the transaction.
ii. If not, please provide a payment schedule and describe the accounting treatment of the off-setting entry to intangible assets.
iii. Does Festival Hydro expect to incur future costs related to the bypass agreement?
e) Please explain how Festival believes the Stratford Transformer Station Permanent Bypass meets the definition of an intangible asset under IAS 38.
f) Please indicate if Festival has discussed this with its external auditor and provide any documents received by Festival that express the views and opinions of its external auditor.

Response:

a) Confirmed. $1.23M has been added to the rate base for the Permanent Bypass Agreement with HONI.

b) At the time of creating the Transformer Station (TS) budget, it was not envisage that a Permanent Bypass arrangement was going to be required.

c) Below is the table presented in Festival's 2013 IRM Application (EB-2012-0124) comparing the various options available to Festival Hydro for construction of the TS. The decision to build was not solely based on the Net present value of the best option, but also on how the option would best address other critical factors such as capacity requirements, voltage issues and reliability performance. The preferred option which addressed all issues and was also the lowest cost was the 4th option - Festival Hydro to construct the TS.

Scenario	NPV[1]	Address Capacity Issue?	Address Voltage Issue?	Address Reliability Issue?
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Hydro One Builds Second TS in 2015	$16.8M	yes	Not until 2015	Minimal until 2015
Hydro One Replaces One Transformer at Devon TS in 2010, Festival Builds New Feeder in 2010, Festival Hydro Builds Second TS in 2015	$14.7M	yes	Not until 2015	Minimal until 2015
Hydro One Builds Second TS in 2010	$13.3M	yes	yes	Yes
Festival Hydro Builds Second TS in 2010	$10.5M	yes	yes	Yes

Festival is of the opinion that with the addition of the cost of the Permanent Bypass the decision for Festival to construct was still the best option. The TS has been successfully up and operational since December 2013 with minimal problems encountered. With the TS build completed by Festival, Festival has been able to successfully achieve the requirements of the other major criteria identified as critical to the project, that being the issues of capacity, voltage and reliability.

Outlined below is the financial analysis of the actual TS expenditure compared to budget if Permanent Bypass is considered :

Original TS Budget	$15,863,114 (on page 15 of 2013 IRM)	
Actual Expenditures:		
Capital spend	$15,311,782 (capital transferred to 1508)	
Permanent Bypass	1,025,481	($1,230,026 in 2010 dollars)
Total Capital Spend	$16,337,263	
Amount over original budget	$ 474,149	

If the over budget amount of $474K is added to the original projected NPV of $10.5 the amount of $11.0M is still less than the $13.3M for the second lowest cost option, and this is without even taking into account the $475K being saved annually on transmission connection charges.

d) The $1.23M bypass agreement was set up as an Accounts Payable at December 31, 2013. The transformer station went into service on December 2, 2013 and Festival's customers have been receiving the benefits of reduced transmission charges since that date through reductions in transmission charges form the IESO. However, the bypass assessment date is not being completed until in or around June 1, 2014, and the payment due date is 180 days following that, so Festival

[1] A discount rate of 5.5% was used. Adjusting the discount rate from a low of 2.5% to a high of 7.5% made no difference in the relative ranking of the scenarios.

Hydro expects to make the payment in December 2014. The accounting entry to set up the bypass agreement as an asset was Debit 1609 Capital Contributions Paid and Credit # 2205 Accounts Payable. Upon settlement, the entry will be to Debit #2205 Accounts Payable and Credit #1005 Cash. At this time, Festival does not expected to incur any additional costs related to the Permanent Bypass. Excerpts from the Permanent Bypass agreement are copied below:

in or around June 1, 2014, the Customer intends to by-pass Hydro One's Stratford TS (the "**Station & Line Assets**") in respect of a portion of the Existing Load; and

Bypass Compensation – Estimate:

$$\underline{\mathbf{\$1,230,026}} = [NBV_T + DC_T - SC_T] \times [BC/TNSC_T] + [NBV_L + DC_L - SC_L] \times [BC/TNSC_L]$$

e) Article 410 of the OEB Handbook is fairly specific that intangible assets include capital contributions paid by the distributor to other distributors for capital projects. While the payment was not directly attributed to a capital project of another distributor, it was a payment to HONI to facilitate the full operation of the asset Festival constructed. The account definition of USOA # 1609 states "This account shall include capital contributions paid by a distributor to a host distributor, a transmitter or a generator for capital expenditures (e.g., under a Connection and Cost Recovery Agreement) that meet the IAS 38 Intangible Assets requirements for classification as an intangible asset. "The nature of the agreement fits the description of Acct # 1609
From an IAS 38 standpoint:
   a) The payment meets the definition of an asset - it is an identifiable non-monetary asset without physical substance that was/is controlled by Festival as a result of past events; and will derive future economic benefit from making the payment.
   b) The payment is identifiable because it meets both criteria in IAS 38, paragraph 12.
   c) Festival controls the asset – as Festival has the power to obtain future economic benefit from it – i.e. the ability to distribute power through the TS and bill customers for it
   d) Can be recognized as an intangible according to IAS 38, paragraphs 21 and 22, because the payment meets the criteria required for recognition as an intangible.

f) The accounting treatment was discussed in advance of the 2013 yearend audit with our external auditors to ensure proper accounting treatment was met. Being it was a material dollar value, the agreement was subject to external audit review. In the Notes to the 2013 audited financial statements, Section 1 Significant Accounting Policies – section f) provides the policy related to Intangible Assets. Under Note 5 is provided the details of the agreements associated with the balance in the Intangible Asset account.

The auditors issued an unqualified auditors' report on Festival's 2013 financial statements which include this amount being included as an intangible asset.

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13. UNDERTAKING NO. JT1. 12:

Ref: Page 43

To explain why O&M and the Bypass Agreement are included in the Deferral account.

Response:

The ICM account # 1508 as presented by Festival includes the following: the capital costs of constructing the TS, the operating costs for 2013 and 2014, funding collected through the ICM rate rider since May 1, 2013 and carrying charges at rate of 1.47%.

Just to clarify, the Permanent Bypass Agreement is not included in the ICM model. It was a spending decision made separate from the Transformer Station construction costs and the spending was justified like any other capital expenditure undertaken by Festival. Under previous accounting rules, consideration would have been made to add this directly to the asset account USoA # 1815. However, based on accounting rules (CGAAP 3048 and IAS 48) in place in 2013, this capital spend has been recognized as an intangible asset, which is described in depth under JT 1 14.

Operating and Maintenance (O & M) Expenses of the Transformer station (TS) included in the ICM account:

Festival included in the ICM variance account the O&M associated with operating the TS station in 2013 and 2014. The same accounting principles were applied as were followed for smart meters. For both smart meters and TS construction, the 2010 rate application did not include the operating costs associated with these assets. Festival has since learned that the ICM policy does not allow for O & M expenses to be included in the ICM account.

In the event these expenses are removed from the ICM account, Festival has reviewed the various policy options available from the Board and request that these expenses be placed into a variance account and be given Z factor recognition.

In Chapter 3 of the Filing Guidelines the following are the filing guidelines for a Z factor event:

- *A distributor must submit evidence that the costs incurred meet the three eligibility criteria (causation, materiality, prudence)*
- . *A distributor must also:*
    - *Notify the Board promptly by letter to the Board Secretary of all Z-factor events. Failure to notify the Board within six months of the event may result in disallowance of the claim.*
    - *Apply to the Board for any cost recovery of amounts recorded in the Board-approved deferral account claimed under Z-factor treatment. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts for which Z-factor treatment is claimed.*
    - *Provide a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.*

- *Demonstrate that the costs are incremental to those already being recovered in rates as part of ongoing business exposure risk.*

In terms of meeting the criteria of causality, materiality and prudence as described below:

Causality: These costs are unique to the operation of a transformer station and only arise as a result of its operation. In Festival' s 2010 rate application there were no operating expenses as such included in the Board approved O & M, as the TS asset itself was not identified as an expenditure at that time. As such, expenses were incurred in 2013 and are currently being incurred in 2014 as identified in the table below.

Materiality: Festival's materiality is 0.5% of revenue requirement, which based on the RWWF filed with these filing totals close to $57,000. The expenses incurred in 2013 and projected for 2014 total $104,815 and $140,000, respectively. These expenses in each of 2013 and 2014 exceed materiality.

Prudence: The major cost components for the 2013 and 2014 expenses are noted in the table below. Being the station is new the costs being claimed are routine O & M costs. In terms of the station monitoring cost , rather than hiring staff to provide 24-7 coverage (which would have been expensive) , an RFP was put out to surrounding LDCs, with TS monitoring stations, for site monitoring services. Festival assessed the LDCs on various criteria including price, with the lowest priced vendor being selected for site monitoring.

O & M Expenses	2013	2014
Training Costs	39,826	$ 3, 000
TS Monitoring Costs	3,750	15,000
TS Communication Costs	16,614	24,500
Property taxes	9,926	21,500
Insurance & property protection	7,395	18,000
SCADA maintenance		5,000
Internal labour & trucking costs	18,003	13,000
Station maintenance	9,301	40,000
Total	**$ 104,815**	**$ 140,000**

In terms of meeting the six month criteria of notification to the Board, Festival did not originally report the expenses as they did not originally envisage this as being a Z factor claim. The fact these expenses existed were first reported to the Board as part of this original rate application file May 27, 2014. Most of the 2013 expenses were incurred in the last half of 2013.

At a minimum, Festival feels the 2014 costs should be subject to Z factor treatment as these costs are currently being incurred. With respect to 2013 costs, being these costs were not part of 2010 rates, and were not foreseeable costs at that time, Festival submits the 2013 costs also be allowed recovery through the Z factor account. These costs are all incremental in nature.

Festival proposes placing these costs for 2013 and 2014 into account # 1572 Extraordinary Event Costs. Festival has included these amounts on the EDVARR schedule to be disposed of as part of the Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.). The bill impacts under Undertaking JT 1.24 have been presented including the $244,815 in the variance account.

14. UNDERTAKING NO. JT1. 13:

Ref: Page 49

To update the response to 4-STAFF-75-TCQ regarding the employee future benefit accrual.

Response:

Festival incorrectly reported the amount of $44,850 as owing to Festival Hydro, when in fact it is owing to the customers as follows:

2015 DVA Account

Required:

Closing Accrual under CICA, Dec 31, 2014	1,401,958	(Festival accrued/expensed)
Closing Accrual under IAS19, Dec 31, 2014	1,357,108	(Accrual needed under IAS 19)
Difference arising on converting to IFRS	44,850	(owing to ~~Festival Hydro~~customers)

The deferral account, if directed by the Board to be established, will be recorded as a payable to customers. The amount does not meet the materiality level, however, from a causality point of view; it was Festival's belief that LDCs and the ratepayer would be held whole on amounts arising from the conversion from CGAAP to IFRS.

The bill impacts under Undertaking JT 1.24 have been presented including the $(44,850) in the DVA accounts. Festival has included it in the Acct 1572, as an offset to the $244,815 TS expenses for net amount of $199,965.

15. UNDERTAKING NO. JT1. 14:

Ref: Page 50

To provide a letter from Festival's auditor that under IFRS a bypass agreement would be considered an intangible asset.

Response:

Festival again contacted our auditors regarding a letter and their response was that they prefer not to provide an opinion to a governing body on a single accounting decision. As noted, in our previous submissions, the auditors have issued an unqualified opinion on the 2013 financial statements, which presents the permanent bypass as an intangible asset.

The discussion to date has related to whether the permanent bypass constitutes an intangible asset. At the technical conference, it was suggested by Board staff that it may be considered a penalty (i.e. expense). To support Festival's arguments for intangible asset treatment, as opposed to an expense or penalty item, the following analysis of assets versus expenditures is being presented.

Background

Festival Hydro Inc. ("Festival") constructed a new TS Station in Stratford. Festival's new TS Station was put into operation in December 2013, and had the capacity to service customers previously serviced by a Hydro One Inc. ("HONI") TS Station. Festival desired to connect these customers to its new TS Station in order to improve their service and reliability.

In order to energize the Festival TS Station and connect these customers by by-passing the HONI Stratford Station, Festival was given two options; a temporary or permanent by-pass agreement with HONI. Management's analysis showed that with the temporary by-pass arrangement, Festival had to ensure there was no loss revenue to HONI, so from a customer's financial perspective the customer was indifferent as to the bypass arrangement. However, through the $1.2 million permanent by-pass agreement, customers would receive an annual net benefit of $475,000 through a reduction of transmission connection charges to customers.

As the permanent by-pass agreement option provided a generous benefit to customers, Festival entered into an agreement with HONI to pay approximately $1,230,000 for the right to by-pass 20 MW of load from the HONI TS Station. The by-pass charge is directly related to both the capital spend on the new TS Station (i.e. the charge would not have been incurred if the new TS Station had not been built), the future benefit to customers (the permanent by-pass option benefits customers approximately $475,000 annually), and Festival's ability to improve service and reliability to its customers.

Accounting Treatment

Does the permanent by-pass charge represent an asset or expenditure?

Under Canadian GAAP, Part IV of the CPA Canada Handbook – Accounting:

1000.29 Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.

1000.30 Assets have three essential characteristics:

(a) they embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and, in the case of not-for-profit organizations, to provide services;

(b) the entity can control access to the benefit; and

(c) the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

In Festival's case, the by-pass charge meets the definition of an asset. Only by payment of the permanent by-pass charge can the net benefit of future cash flows be realized. In addition, Festival controls the TS Station, by virtue of ownership. Customers cannot be connected through the TS Station unless Festival allows the connection, and cannot earn the financial benefit without the existence of the permanent bypass and existence of the TS itself. The transaction giving the right to or control of, the benefit occurred when the TS Station was put into operation and the by-pass agreement signed in December of 2013.

If we compare the definition of an asset to an expense, alternatively, expenses are defined in CPA HBV 1000.38 as:

Decreases in economic resources, either by way of outflows or reduction of assets or incurrences of liabilities, resulting from an entity's ordinary revenue generating or service delivery activities.

As expenses typically relate to the performance of service or revenue generating activities, they would typically be recorded when the full benefit of any outlay has been realized (i.e. revenue has been generated, or an asset has been used to completion). An expense could also be incurred if the future benefits from the expense could not be measured reliably.

In the case of the by-pass agreement charge, the outlay cannot be an expense as the charge provides the right to recover future cash flows from providing service to customers. The benefit of the charge will be realized in the current year and many future dates. This benefit can also be forecasted reliably by management. Furthermore, it is the future potential of revenue generation or service delivery activities that led to the charge, not current revenue or service delivery activities.

<u>What is the nature of the payment?</u>

It should also be considered as to what the actual by-pass charge is for. The calculation of the by-pass charge shows that the payment relates primarily to lost future transmission for HONI as the decommissioning costs are actually less than the salvage value of the HONI TS Station. If the decommissioning cost was higher than salvage, we would expect that a portion of the payment would be for past service used; however, this is not the case. As a result, it appears that Festival is paying for lost future transmission by HONI (essentially the right to the customer base). This is more indicative of an asset which relates to future economic benefit than an expense.

<u>Future Treatment under existing IFRS Standards</u>

The IFRS definition of an asset is more detailed, however, less prescriptive (IFRS "The conceptual framework for financial reporting – Chapter 4.8 – Assets"). Under IFRS, assets embody future economic benefits and result from a past transaction or event. However, control does not necessarily need to be established in order for an asset to exist.

Under existing IFRS standards, it is reasonable that the permanent by-pass charge would also be considered an asset.

Is the Payment to HONI an Intangible asset or an item of Property Plant and Equipment?

Property, Plant and Equipment ("PP&E")

Under Canadian GAAP, Part IV of the CPA Canada Handbook – Accounting:

3061.04, PP&E are identifiable tangible assets that meet all of the following criteria:

(a) are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other property, plant and equipment;

(b) have been acquired, constructed or developed with the intention of being used on a continuing basis; and

(c) are not intended for sale in the ordinary course of business.

The by-pass charge, in and of itself, does not appear to directly meet the above criteria as it lacks physical substance (i.e., not tangible). However, the new transformer station that was constructed does meet this definition.

Under 3061.10, rate regulated PP&E are items of PP&E held for use in operations meeting all of the following criteria:

(a) *The rates for regulated services or products provided to customers are established by or are subject to approval by a regulator or a governing body empowered by statute or contract to establish rates to be charged for services or products.*

(b) *The regulated rates are designed to recover the cost of providing the services or products.*

(c) *It is reasonable to assume that rates set at levels that will recover the cost can be charged to and collected from customers in view of the demand for the services or products and the level of direct and indirect competition. This criterion requires consideration of expected changes in levels of demand or competition during the recovery period for any capitalized costs.*

Based on our understanding of the use of the transformer station and the rate setting process, it is reasonable to assume that the transformer station itself is an item of rate regulated PP&E.

CPA Canada HBV 3061.05 defines the cost as "the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use".

Further guidance as to what is included in the cost of PP&E is provided in CPA Canada HBV 3061.17 as follows:

Purchase price and other acquisition costs such as option costs when an option is exercised, brokers' commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges.

While the Standard doesn't specially list by-pass costs, it is clear that the expenditure on the permanent bypass would not have occurred without the existence of the new transformer station into service; and can be argued that the charge is directly attributable.

Further to be considered is the recoverable amount of the charge, if included in PP&E. Assuming the regulator will permit the inclusion of the charge as a component of PP&E for the purposes of rate setting, it is reasonably certain that the amount will be recovered in future periods.

Intangible Asset

Since the by-pass charge lacks physical substance, it should be considered whether the charge is representative of an intangible asset.

CPA Canada HBV 3064.04 provides guidance with respect to the classification between PP&E and intangible assets:

Standards for the recognition, measurement, presentation and disclosure of tangible capital assets are provided in PROPERTY, PLANT AND EQUIPMENT, Section 3061. Some intangible assets may be contained in or on a physical substance such as a compact disc (in the case of computer software), legal documentation (in the case of a license or patent) or film. In determining whether an asset that incorporates both intangible and tangible elements should be treated under Section 3061 or as an intangible asset under this Section, an entity uses judgment to assess which element is more significant. For example, computer software for a computer-controlled machine tool that cannot operate without that specific software is an integral part of the related hardware and it is treated as property, plant and equipment. The same applies to the operating system of a computer. When the software is not an integral part of the related hardware, computer software is treated as an intangible asset.

In Festival's case, the by-pass charge is a payment to compensate for the decommissioning of the existing asset or cost associated with the stranded asset. As it has been argued in the PPE discussion, this was a critical payment with the purpose of creating future economic benefits to Festival Hydro and to its customers. As a result, it may be more appropriate to recognize the by-pass charge as an asset separate from the TS Station.

CPA Canada HBV 3064.11 describes the criteria for recognition of intangible assets. First, an intangible asset needs to meet the definition of an intangible asset (identifiable, control, future economic benefits). Second, the recognition criteria must be met.

In meeting the definition criteria, identifiability is met as the by-pass charge arose from a contractual right (3064.12(b)). Control over future economic benefits has been established by virtue of ownership of the TS station and the payment of the by-pass fee, which gives Festival control over servicing the customer base. Finally, future economic benefits are expected from the by-pass agreement payment both to Festival, in being able to service customers reliably, and to the customers in terms of future savings. This is not possible without the payment to HONI, as is the situation in the temporary bypass arrangement.

The by-pass charge meets the recognition criteria (3064.21-23) since it is probable that the expected future economic benefits attributable to the asset will flow to the entity and the cost of the asset is measured reliably. As previously discussed, future economic benefits will be received as a result of the by-pass agreement, primarily through obtaining new customers. The cost of the asset is measured reliably as it is outlined in a calculation as part of the by-pass agreement.

Conclusion on classification

The nature of the by-pass payment is that it could be treated as either an intangible asset or PPE. The payment is for a right to access customers and obtain future economic benefit for Festival. This would lead towards treatment as a definite life intangible asset as the asset meets the criteria for recognition. Separate treatment from the PPE TS Station asset may be desirable as it would better highlight the underlying nature of the transaction and seems to comply more reasonably with the guidance in 3064 & 3061. However, the asset could also be reclassified to PPE and shown as a component of the TS Station, since the asset would not exist without the existence of the TS. In either event, the amortization of the asset would be consistent with the TS Station itself and would not have an impact on the amortization affecting the Statement of Operations. Furthermore, whether the classification should be PPE or Intangible is not significant or material to the financial statements as both asset classifications are long-term.

Treatment under current IFRS

The treatment for recognition of PPE (IAS 16.7) under IFRS is similar to CPA HB V. Assets are recognized as PPE when it is probable that future economic benefits associated with the item will flow to the entity and the cost of the item can be measured reliably. As discussed above, both of these arguments are met. Furthermore IAS16.11 indicates that initial costs may be PPE if they are directly or indirectly related to items of PPE to obtain future economic benefits. Under the current standards it is reasonable to assume that the asset would be able to be recognized as PPE under IAS16.

Similarly, IAS 38.11-24 Intangible Assets currently set out the same criteria as CPA HBV – 3064 (identifiability, control, future economic benefit, etc.). The guidance in both handbooks point to the asset meeting the recognition criteria. As we have noted above in the CPA HBV-3064 section, the following (IAS38.21-22) has been met as well using the same arguments:
IAS38.21 An intangible asset shall be recognized if, and only if:
(a) it is probable that the expected future economic benefits that are attributable to the asset will flow to the entity; and
(b) the cost of the asset can be measured reliably.
IAS38.22 An entity shall assess the probability of expected future economic benefits using reasonable and supportable assumptions that represent management's best estimate of the set of economic conditions that will exist over the useful life of the asset.

Additional considerations
The OEB has issued the Accounting Procedures Handbook ("APH") for Electricity Distributors in order to provide guidance in accounting for transactions. The following are excerpts from the APH related to intangible assets:

Article 220 (Balance Sheet Accounts) describes intangible assets:

1609 Capital Contributions Paid

This account shall include capital contributions paid by a distributor to a host distributor, a transmitter or a generator for capital expenditures (e.g., under a Connection and Cost Recovery Agreement) that meet the IAS 38 Intangible Assets requirements for classification as an intangible asset.

1610 Miscellaneous Intangible Plant

This account shall include the cost of patent rights, licenses, privileges, capitalizable load profile development costs and other intangible property necessary or valuable in the conduct of utility operations and not specifically chargeable to any other account.

Article 410 (Property, Plant and Equipment and Intangible Assets) of the OEB Accounting Procedures Handbook describes accounting for contributions in aid of construction and states:

Contributions paid by a distributor: in some cases distributors will incur expenditures for amounts paid to other distributors or transmitters for capital projects. Distributors who incur such costs, should record the amounts in USoA Account 1609, Intangible Assets – Capital Contributions Paid.

Expenses
The APH does not provide guidance specific to 'penalty payments'.

It is reasonable to conclude that the APH guide suggest using 1609 Capital Contributions Paid (an intangible account). While the payment was not directly attributed to a capital project of another distributor, it was a payment to HONI to facilitate the full operation of the asset Festival constructed and the asset meets the requirements of IAS38.

Conclusion

It is Festival's opinion that after review of the transaction facts and applicable accounting guidance, the transaction embodies the characteristics of an asset and not an expense. Furthermore, the asset meets the definition of an intangible asset under CGAAP and IAS38. The asset could also be considered part of the PPE costs required to get the asset ready for its intended use. However, for accounting purposes, the impact to the financial statements would not be significantly different, aside from the intangible being reported on a separate line item than PPE.

The other factor that needs emphasized is that Festival entered in to this permanent bypass arrangement for the financial benefit to the customer. From Festival's perspective, the transfer of 20 MWh of load represents benefits interms of improved service and reliability. Not to forget, Festival could have entered into a temporary bypass which would have been revenue natural for customers and achieved the same results for Festival. Festival made a conscious decision to add this asset to their rate base and to invest the $1.2 million so as to pass along the $475,000 annual savings to its customers. It is arguably a good investment in terms of return on investment from the customer's perspective.

Festival had not looked into any other Board document or policy on guidance as to where the permanent bypass should be classified because Festival was confident it met the definition of an intangible asset and that it also met the criteria of USoA # 1609.

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To provide the difference in cost or revenue requirement if Festival were to use a deferral account to recover the amount of the bypass penalty over three years.

Response:

Festival has completed an analysis comparing the NPV associated with treating the asset as an intangible asset within rate base compared to the recovery as a Deferral account over 3 years. As noted in the table below, including the costs in the rate base over a 45 year life span results in a much higher NPV value than treating it as an asset in a Deferral account.

With the deferral account method, there is a small positive net present value arise on the 3 year deferral account whether it is financed over a 25 year period or a 3 year period. This positive return is primarily due to the fact that the deferral account, which will be established effective January 1, 2014, will have the full value of the contract of $1,230,026 added to the account. At the OEB prescribed interest rate of 1.47%, that will result in $18,081 carrying charges being earned in 2014. Since Festival does not expect to borrow the funds until December 2014 at the earliest, the carrying charges earned in 2014 and 2015 to 2017 will more than offset the cost of borrowing associated with the loan over the three year period (the loan being calculated at 2.24% - the Infrastructure Ontario's current 5 year rate).

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(b) are expected to be used during more than one period."

Further, paragraph 7 specifically states that the cost of an item of property, plant and equipment shall be recognized as an asset if, and only if:

"(a) it is probable that future economic benefits associated with the item will flow to the entity; and
(b) the cost of the item can be measured reliably."

Intangible Assets (IAS 38)

Paragraph 8 defines an intangible asset as "an identifiable non-monetary asset without physical substance." For distributors, this may include: software, land rights, and capital contributions *paid* by the distributor.

Paragraphs 9 – 17 discuss the 3 attributes that must exist in order to meet the definition of an intangible asset, being: Identifiability, Control and Future economic benefits.

Similar to IAS 16, IAS 38 paragraph 21 states that an intangible asset shall be recognized if, and only if:

"(a) it is probable that the expected future economic benefits that are attributable to the asset will flow to the entity; and
(b) the cost of the asset can be measured reliably."

Capital Assets (includes property, plant and equipment as well as intangible assets)

In summary, in order for an expenditure on a tangible item to qualify as property, plant and equipment, or an intangible item to qualify as intangible assets, it should meet both the definitions of an asset under the Framework and of IAS 16 or IAS 38 as discussed above.

Measurement at recognition

Property, Plant and Equipment (IAS 16)

For a complete discussion on the measurement of property, plant and equipment at recognition, refer to paragraphs 15-22 of IAS 16.

Property, plant and equipment should be measured at its cost, which includes (paragraph 16):

"(a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.
(b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.
(c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period."

Paragraph 17 outlines examples of directly attributable costs:

"(a) costs of employee benefits (as defined in IAS 19 *Employee Benefits*) arising directly from the construction or acquisition of the item of property, plant and equipment;

(b) costs of site preparation;

(c) initial delivery and handling costs;

(d) installation and assembly costs;

(e) costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and

(f) professional fees."

Also as noted in paragraph 22, borrowing costs (IAS 23) that are directly attributable to the acquisition, construction or production of a qualifying asset form part of the cost of that asset – see section on borrowing costs below.

Paragraphs 19 and 20 describe costs that are not costs of an item of property, plant and equipment and also describe when recognition of costs in the carrying amount ceases.

Examples of costs that are not costs of an item of property, plant and equipment are:

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(a) costs of opening a new facility;
(b) costs of introducing a new product or service (including costs of advertising and promotional activities);
(c) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
(d) administration and other general overhead costs. (paragraph 19)

Recognition of costs in the carrying amount of an item of property, plant and equipment ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management. Therefore, costs incurred in using or redeploying an item is not included in the carrying amount of that item. For example, the following costs are not included in the carrying amount of an item of property, plant and equipment:

(a) costs incurred while an item capable of operating in the manner intended by management has yet to be brought into use or is operated at less than full capacity;
(b) initial operating losses, such as those incurred while demand for the item's output builds up; and
(c) costs of relocating or reorganising part or all of an entity's operations. (paragraph 20)

Intangible Assets (IAS 38)
Paragraphs 25 – 67 include a discussion on recognition and measurement of intangible assets that may be acquired through the following:

Acquisition type	IAS 38 Section References
Separate acquisition	Paragraphs 25-32
Acquisition as part of a business combination	Paragraphs 33-43
Acquisition by way of a government grant	Paragraph 44
Exchanges of assets	Paragraphs 45-47
Internally generated goodwill	Paragraphs 48-50
Internally generated intangible assets	Paragraphs 51-67

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Distributors that acquire intangible assets other than through separate acquisition (i.e. purchases) as discussed below should refer to the detailed guidance provided in IAS 38.

Paragraph 24 states that an intangible asset shall be measured initially at cost. Where an intangible asset is acquired through separate acquisition, the cost is comprised of the following (paragraphs 27 and 28):

> "(a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates; and
> (b) any directly attributable cost of preparing the asset for its intended use.
>
> Examples of directly attributable costs are:
> (a) costs of employee benefits (as defined in IAS 19) arising directly from bringing the asset to its working condition;
> (b) professional fees arising directly from bringing the asset to its working condition; and
> (c) costs of testing whether the asset is functioning properly."

Paragraph 29 provides examples of expenditures that are not part of the cost of an intangible asset:

> (a) costs of introducing a new product or service (including costs of advertising and promotional activities);
> (b) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
> (c) administration and other general overheads.

Similar to property, plant and equipment, recognition of costs in the carrying amount of an intangible asset ceases when the asset is "in the condition necessary for it to be capable of operating in the manner intended by management."

Capital Assets (includes property, plant and equipment as well as intangible assets)
For components of construction cost, refer to Article 230 *Definitions and Instructions* No. 6.

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Accounting for Specific Items

Property, Plant & Equipment and Intangible Assets

The Board requires utilities to adhere to IFRS capitalization accounting requirements for regulatory reporting and rate-making purposes after the date of adoption of IFRS. It should be noted that in determining the cost of property, plant and equipment and intangible assets to be included in the rate base, where the proposed cost is, in the opinion of the Board, not reasonable for inclusion in the rate base, the Board can make its own determination of the cost to be included in rate base.

Subsequent Costs (Capitalization)

Under previous Canadian GAAP, this subsection of Article 410 was labeled "Betterments versus Repairs". While the concepts contained within IFRS are similar to Canadian GAAP, IAS 16 and IAS 38 do not refer to subsequent costs that are eligible for capitalization as 'betterments'. This is mentioned only for the purposes of making the reader aware of the linkage of "subsequent costs" in this discussion to the previous accounting issue.

<u>Property, Plant and Equipment (IAS 16)</u>
Paragraphs 12-14 describe subsequent costs.

"Under the recognition principle in paragraph 7, an entity does not recognise in the carrying amount of an item of property, plant and equipment the costs of the day-to-day servicing of the item. Rather, these costs are recognised in profit or loss as incurred. Costs of day-to-day servicing are primarily the costs of labour and consumables, and may include the cost of small parts. The purpose of these expenditures is often described as for the 'repairs and maintenance' of the item of property, plant and equipment." (paragraph 12)

"Parts of some items of property, plant and equipment may require replacement at regular intervals. For example, a furnace may require relining after a specified number of hours of use, or aircraft interiors such as seats and galleys may require replacement several times during the life of the airframe. Items of property, plant and equipment may also be acquired to make a less frequently recurring replacement, such as replacing the interior walls of a building, or to make a nonrecurring replacement. Under the recognition principle in paragraph 7, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria are met. The carrying amount of those parts that are replaced is derecognised in accordance with the derecognition provisions of this Standard (see paragraphs (67 - 72)." (paragraph 13)

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"A condition of continuing to operate an item of property, plant and equipment (for example, an aircraft) may be performing regular major inspections for faults regardless of whether parts of the item are replaced. When each major inspection is performed, its cost is recognised in the carrying amount of the item of property, plant and equipment as a replacement if the recognition criteria are satisfied. Any remaining carrying amount of the cost of the previous inspection (as distinct from physical parts) is derecognised. This occurs regardless of whether the cost of the previous inspection was identified in the transaction in which the item was acquired or constructed. If necessary, the estimated cost of a future similar inspection may be used as an indication of what the cost of the existing inspection component was when the item was acquired or constructed." (paragraph 14)

<u>Intangible Assets (IAS 38)</u>
Paragraph 20 describes subsequent costs.

"The nature of intangible assets is such that, in many cases, there are no additions to such an asset or replacements of part of it. Accordingly, most subsequent expenditures are likely to maintain the expected future economic benefits embodied in an existing intangible asset rather than meet the definition of an intangible asset and the recognition criteria in this Standard. In addition, it is often difficult to attribute subsequent expenditure directly to a particular intangible asset rather than to the business as a whole. Therefore, only rarely will subsequent expenditure – expenditure incurred after the initial recognition of an acquired intangible asset of after completion of an internally generated intangible asset – be recognized in the carrying amount of an asset..." (paragraph 20)

Measurement after Recognition

It should be noted that both IAS 16 and IAS 38 include the concept of a "Revaluation Model", whereby property, plant and equipment or intangible assets whose fair value can be measured reliably may be carried at a revalued amount if the entity so chooses. Otherwise, the entity carries such items at historical cost less accumulated depreciation.

The Board requires that for regulatory accounting and rate-making purposes, distributors use historical acquisition cost as the basis for reporting property, plant and equipment as well as intangible assets, even though a distributor may for financial reporting elect to report these assets at revalued amounts as permitted by IFRS.

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Derecognition, Disposal and Retirement

Property, Plant and Equipment (IAS 16)
Paragraphs 67 and 68 state the following:

"The carrying amount of an item of property, plant and equipment shall be derecognized:

(a) on disposal; or
(b) when no future economic benefits are expected from its use or disposal." (paragraph 67)

"The gain or loss arising from the derecognition of an item of property, plant, and equipment shall be included in profit or loss when the item is derecognized (unless IAS 17 *Leases* requires otherwise on a sale and leaseback). Gains shall not be classified as revenue." (paragraph 68)

Intangible Assets (IAS 38)
Similarly, for intangible assets paragraphs 112 and 113 state the following:

"An intangible asset shall be derecognized:

(a) on disposal; or
(b) when no future economic benefits are expected from its use or disposal." (paragraph 112)

"The gain or loss arising from the derecognition of an intangible asset shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset. It shall be recognized in profit or loss when the asset is derecognized (unless IAS 17 requires otherwise on a sale and leaseback). Gains shall not be classified as revenue." (paragraph 113)

Like Assets
Like assets are those individually insignificant items that by their nature may make identification of individual items impractical for accounting purposes. The vintage basis of depreciation refers to a system of categorizing like assets together for depreciation purposes using a depreciation method that will allocate the combined cost of the assets over their estimated useful life in a rational and systematic manner. This accounting treatment recognizes that it is not always practicable to separately track individual units of an insignificant nature, however still requires separate tracking of the aggregate number of units recognized within a particular vintage for depreciation purposes. Refer

to discussion below for derecognition treatment where the tracking of the aggregate number of units recognized within a particular vintage is not practicable.

Further, paragraphs 45-47 of IAS 16 state that:

"A significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge." (paragraph 45)

"To the extent that an entity depreciates separately some parts of an item of property, plant and equipment, it also depreciates separately the remainder of the item. The remainder consists of the parts of the item that are individually not significant. If an entity has varying expectations for these parts, approximation techniques may be necessary to depreciate the remainder in a manner that faithfully represents the consumption pattern and/or useful life of its parts." (paragraph 46)

"An entity may choose to depreciate separately the parts of an item that do not have a cost that is significant in relation to the total cost of the item." (paragraph 47)

For the purposes of applying the USoA and for regulatory reporting, distributors have the option of categorizing "like assets" together consistent with IAS 16 requirements discussed above, but which is dissimilar to the treatment of readily identifiable, due to the following circumstances:

a) Regulatory accounting practice recognizes that it may be appropriate to categorize individually insignificant capital assets together. As an example, for some distributors, the individual unit cost of certain assets such as poles, conductor, transformers and meters does not justify the time and effort to maintain the detailed accounting systems that would be required to track such items individually.

b) The vintage basis of depreciation will continue to allow the combined cost of the assets to be allocated over their estimated useful life in a rational and systematic manner.

c) Allowing distributors to categorize like assets together avoids placing an undue burden that would be associated with requiring individually insignificant assets to be separately accounted for.

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It is difficult to prescribe one method of determining gross asset value for the individual assets in a particular vintage as there are several factors which may affect which approach a utility may use (e.g. state of records). There are a number of implementation alternatives and use of professional judgment is required. For regulatory reporting and rate-making purposes, the vintage basis may be used such that costs of purchases for a year are averaged and the average cost for that year is applied when an asset of that vintage is retired. Where the distributor has not tracked the number of units pertaining to a specific vintage due to impracticability, when a 'like asset' is derecognized, the distributor shall retire the amounts that would otherwise be required for general financial statement reporting purposes, and these amounts should also be used for regulatory accounting purposes to avoid financial differences.

Gains or losses on derecognition, disposal, retirement or impairment of like assets should be recorded in Account 4355, Gain on Disposition of Utility and Other Property, Account 4357, Gain from Retirement of Utility and Other Property, Account 4360, Loss on Disposition of Utility and Other Property or Account 4362, Loss from Retirement of Utility and Other Property, as appropriate. (See account details in Article 220 *Account Descriptions.*)

Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense (on the income statement), and disclose the amount separately.

The gain or loss should be reclassified into the following USoA account under a separate sub-account:

- Account 5705, Amortization Expense. This account shall include the amount of amortization expense for all classes of depreciable Electric Plant in Service except such amortization expense as is chargeable to clearing accounts or to Account 4330, Costs and Expenses of Merchandising.

  The utility shall keep such records of property and property retirements as will reflect the service life of property which has been retired and aid in estimating probable service life by mortality, turnover, or other appropriate methods; and also such records as will reflect the percentage of salvage and costs of removal for property retired from each account, or subdivision thereof, for depreciable electric plant.

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Readily Identifiable Assets

A readily identifiable asset is an asset that has a significant unit cost for general financial reporting purposes under IFRS and is tracked on an individual unit basis (i.e., not a 'like asset' as discussed above). Accordingly, any property, plant and equipment asset that is readily identifiable in the plant records should be separately accounted for and depreciated over its estimated useful life. The asset must remain on the books as long as the asset exists and is capable of providing future benefit.

Gains or losses on derecognition, disposal, retirement or impairment of readily identifiable assets should be recorded in Account 4355, Gain on Disposition of Utility and Other Property, Account 4357, Gain from Retirement of Utility and Other Property, Account 4360, Loss on Disposition of Utility and Other Property or Account 4362, Loss from Retirement of Utility and Other Property, as appropriate. (See account details in Article 220 *Account Descriptions.*)

Where a distributor for general financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate application filings for review by the Board. The Board may require the difference between net carrying amount and the proceeds and disposal/retirement costs on disposal of property, plant and equipment or intangible assets to be considered in the determination of future rates charged to customers. In such circumstances the difference is deferred, provided that there is reasonable assurance that:

a) any excess of net carrying amount over proceeds on disposal will be recovered through future rates; or
b) any excess of proceeds on disposal over net carrying amount will serve to reduce future rates.

In summary, in considering whether to defer or expense gains or losses on derecognition, disposal, retirement or impairment of capital assets, a distributor needs to determine whether these gains or losses are to be recovered from future rates. In general, gains or losses should be deferred if they will be included in future rates. However, the Board reserves the right to review the accounting treatment applied and recommend different accounting treatment if deemed appropriate.

For distributors that have recorded amounts in Account 2040, Electric Plant Held for Future Use, specific deferred gain, loss, and related revenue and expense accounts have been provided in the USoA in relation to Account 2040 listed below:

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- Account 1530, Deferred Losses from Disposal of Utility Plant. This account shall include losses from the sale or other disposition of property previously recorded in Account 2040, Electric Plant Held for Future Use, under the provisions of paragraphs B, C, and D thereof, where such losses are significant and are to be amortized over a number of fiscal years and/or as authorized by the Board. The amortization of the amounts in this account shall be made by debits to Account 4350, Losses from Disposal of Future Use Utility Plant. (See Account 2040, Electric Plant Held for Future Use.)

- Account 2410, Deferred Gains from Disposal of Utility Plant. This account shall include gains from the sale or other disposal of property previously recorded in Account 2040, Electric Plant Held for Future Use, under the provisions of paragraphs B, C, and D thereof, where such gains are significant and are to be amortized over a number of years and/or as otherwise authorized by the Board. The amortization of the amounts in this account shall be made by credits to Account 4345, Gains from Disposal of Future Use Utility Plant. (See Account 2040, Electric Plant Held for Future Use.)

- Account 4345, Gains from Disposal of Future Use Utility Plant. This account shall include, as approved by the Board, amounts relating to gains from the disposal of future use utility plant including amounts that were previously recorded in and transferred from Account 2040, Electric Plant Held for Future Use, under the provisions of paragraphs B, C, and D thereof.

- Account 4350, Losses from Disposal of Future Use Utility Plant. This account shall include, as approved by the Board, amounts relating to losses from the disposal of future use utility plant including amounts that were previously recorded in and transferred from Account 2040, Electric Plant Held for Future Use, under the provisions of paragraphs B, C, and D thereof.

- Account 4355, Gain on Disposal of Utility and Other Property. This account shall be credited with the gain on the sale, conveyance, exchange, or transfer of utility or other property to another. Gains on land and land rights recorded in Account 2040, Electric Plant Held for Future Use will be accounted for as prescribed in paragraphs B, C, and D thereof. (See Article 230 *Definitions and Instructions* No. 7(f)).

- Account 4360, Loss on Disposition of Utility and Other Property. This account shall be charged with the loss on the sale, conveyance, exchange or transfer of utility or other property to another. Losses on land and land rights recorded in Account 2040, Electric Plant Held for Future Use will be accounted for as prescribed in paragraphs B, C, and D thereof. (See Article 230 *Definitions and Instructions* No. 7(f)).

Provisions for Decommissioning, Restoration and Similar Costs

Provisions for decommissioning, restoration and similar costs (decommissioning liabilities) are addressed in IAS 37 *Provisions, Contingent Liabilities and Contingent Assets* (IAS 37).

A decommissioning liability is a present obligation relating to the future retirement or removal of a tangible long-lived asset (previously referred to as an asset retirement obligation). A decommissioning liability may arise from either a legal or constructive obligation.

Paragraph 14 of IAS 37 states that:

"A provision shall be recognised when:

(a) an entity has a present obligation (legal or constructive) as a result of a past event;

(b) it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation; and

(c) a reliable estimate can be made of the amount of the obligation.

If these conditions are not met, no provision shall be recognised."

IAS 37, paragraph 10, provides the following definitions.

"An *obligating event* is an event that creates a legal or constructive obligation that results in an entity having no realistic alternative to settling that obligation.

A *legal obligation* is an obligation that derives from:

(a) a contract (through its explicit or implicit terms);

(b) legislation; or

(c) other operation of law.

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IAS 38
Intangible Assets

> **Publisher's Note:** In June 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2017. Earlier application is permitted. If an entity applies the amendment for an earlier period it shall disclose that fact. Paragraphs affected by this amendment include: 3, 114, 116, and 130K.
>
> Click here to view the amendments in PDF Format.
>
> **Publisher's Note:** In May 2014, the IASB issued *Clarification of Acceptable Methods of Depreciation adn Amortisation* (Amendments to IAS 16 and IAS 38), which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies the amendment for an earlier period it shall disclose that fact. Paragraphs affected by this amendment include: 92, 98A-98C, 130J, BC72A, and BC72B-BC72M.
>
> Click here to view the amendments in PDF Format.

In April 2001 the International Accounting Standards Board (IASB) adopted IAS 38 *Intangible Assets*, which had originally been issued by the International Accounting Standards Committee in September 1998. That standard had replaced IAS 9 *Research and Development Costs*, which had been issued in 1993, which itself replaced an earlier version called *Accounting for Research and Development Activities* that had been issued in July 1978.

The IASB revised IAS 38 in March 2004 as part of the first phase of its Business Combinations project. In January 2008 the IASB amended IAS 38 again as part of the second phase of its Business Combinations project.

Other IFRSs have made minor consequential amendments to IAS 38. They include *Improvement to IFRSs* (issued April 2009), IFRS 10 *Consolidated Financial Statements* (issued May 2011), IFRS 11 *Joint Arrangements* (issued May 2011), IFRS 13 *Fair Value Measurement* (issued May 2011) and *Annual Improvements to IFRSs 2010–2012 Cycle* (issued December 2013).

> International Accounting Standard 38 *Intangible Assets* (IAS 38) is set out in paragraphs 1–133. All the paragraphs have equal authority but retain the IASC format of the Standard when it was adopted by the IASB. IAS 38 should be read in the context of its objective and the Basis for Conclusions, the *Preface to International Financial Reporting Standards* and the *Conceptual Framework for Financial Reporting*. IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* provides a basis for selecting and applying accounting policies in the absence of explicit guidance.

Introduction

IN1 International Accounting Standard 38 *Intangible Assets* (IAS 38) replaces IAS 38 *Intangible Assets* (issued in 1998), and should be applied:

(a) on acquisition to the accounting for intangible assets acquired in business combinations for which the agreement date is on or after 31 March 2004.

(b) to all other intangible assets, for annual periods beginning on or after 31 March 2004.

Earlier application is encouraged.

Reasons for revising IAS 38

IN2 The International Accounting Standards Board developed this revised IAS 38 as part of its project on business combinations. The project's objective is to improve the quality of, and seek international convergence on, the accounting for business combinations and the subsequent accounting for goodwill and intangible assets acquired in business combinations.

IN3 The project has two phases. The first phase resulted in the Board issuing simultaneously IFRS 3 *Business Combinations* and revised versions of IAS 38 and IAS 36 *Impairment of Assets*. The Board's deliberations during the first phase of the project focused primarily on:

(a) the method of accounting for business combinations;

(b) the initial measurement of the identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination;

(c) the recognition of provisions for terminating or reducing the activities of an acquiree;

(d) the treatment of any excess of the acquirer's interest in the fair values of identifiable net assets acquired in a business combination over the cost of the combination; and

(e) the accounting for goodwill and intangible assets acquired in a business combination.

IN4 Therefore, the Board's intention while revising IAS 38 was to reflect only those changes related to its decisions in the Business Combinations project, and *not* to reconsider all of the requirements in IAS 38. The changes that have been made in the Standard are primarily concerned with clarifying the notion of 'identifiability' as it relates to intangible assets, the useful life and amortisation of intangible assets, and the accounting for in-process research and development projects acquired in business combinations.

Summary of main changes

Definition of an intangible asset

IN5 The previous version of IAS 38 defined an intangible asset as an identifiable non-monetary asset without physical substance held for use in the production or supply of goods or services, for rental to others, or for administrative purposes. The requirement for the asset to be held for use in the production or supply of goods or services, for rental to others, or for administrative purposes has been removed from the definition of an intangible asset.

IN6 The previous version of IAS 38 did not define 'identifiability', but stated that an intangible asset could be distinguished clearly from goodwill if the asset was separable, but that separability was not a necessary condition for identifiability. The Standard states that an asset meets the identifiability criterion in the definition of an intangible asset when it:

(a) is separable, ie capable of being separated or divided from the entity and sold, transferred, licensed, rented or exchanged, either individually or together with a related contract, asset or liability; or

(b) arises from contractual or other legal rights, regardless of whether those rights are transferable or separable from the entity or from other rights and obligations.

Criteria for initial recognition

IN7 The previous version of IAS 38 required an intangible asset to be recognised if, and only if, it was probable that the expected future economic benefits attributable to the asset would flow to the entity, and its cost could be measured reliably. These recognition criteria have been included in the Standard. However, additional guidance has been included to clarify that:

(a) the probability recognition criterion is always considered to be satisfied for intangible assets that are acquired separately or in a business combination.

(b) the fair value of an intangible asset acquired in a business combination can be measured with sufficient reliability to be recognised separately from goodwill.

Subsequent expenditure

IN8 Under the previous version of IAS 38, the treatment of subsequent expenditure on an in-process research and development project acquired in a business combination and recognised as an asset separately from goodwill was unclear. The Standard requires such expenditure to be:

(a) recognised as an expense when incurred if it is research expenditure;

(b) recognised as an expense when incurred if it is development expenditure that does not satisfy the criteria in IAS 38 for recognising such expenditure as an intangible asset; and

(c) recognised as an intangible asset if it is development expenditure that satisfies the criteria in IAS 38 for recognising such expenditure as an intangible asset.

Useful life

IN9 The previous version of IAS 38 was based on the assumption that the useful life of an intangible asset is always finite, and included a rebuttable presumption that the useful life cannot exceed twenty years from the date the asset is available for use. That rebuttable presumption has been removed. The Standard requires an intangible asset to be regarded as having an indefinite useful life when, based on an analysis of all of the relevant factors, there is no foreseeable limit to the period over which the asset is expected to generate net cash inflows for the entity.

IN10 The previous version of IAS 38 required that if control over the future economic benefits from an intangible asset was achieved through legal rights granted for a finite period, the useful life of the intangible asset could not exceed the period of those rights, unless the rights were renewable and renewal was virtually certain. The Standard requires that:

(a) the useful life of an intangible asset arising from contractual or other legal rights should not exceed the period of those rights, but may be shorter depending on the period over which the asset is expected to be used by the entity; and

(b) if the rights are conveyed for a limited term that can be renewed, the useful life should include the renewal period(s) only if there is evidence to support renewal by the entity without significant cost.

Intangible assets with indefinite useful lives

IN11 The Standard requires that:

(a) an intangible asset with an indefinite useful life should not be amortised.

(b) the useful life of such an asset should be reviewed each reporting period to determine whether events and circumstances continue to support an indefinite useful life assessment for that asset. If they do not, the change in the useful life assessment from indefinite to finite should be accounted for as a change in an accounting estimate.

Impairment testing intangible assets with finite useful lives

IN12 The previous version of IAS 38 required the recoverable amount of an intangible asset that was amortised over a period exceeding twenty years from the date it was available for use to be estimated at least at each financial year-end, even if there was no indication that the asset was impaired. This requirement has been removed. Therefore, an entity needs to determine the recoverable amount of an intangible asset with a finite useful life that is amortised over a period exceeding twenty years from the date it is available for use only when, in accordance with IAS 36, there is an indication that the asset may be impaired.

Disclosure

IN13 If an intangible asset is assessed as having an indefinite useful life, the Standard requires an entity to disclose the carrying amount of that asset and the reasons supporting the indefinite useful life assessment.

International Accounting Standard 38
Intangible Assets

Objective

1 The objective of this Standard is to prescribe the accounting treatment for intangible assets that are not dealt with specifically in another Standard. This Standard requires an entity to recognise an intangible asset if, and only if, specified criteria are met. The Standard also specifies how to measure the carrying amount of intangible assets and requires specified disclosures about intangible assets.

Scope

2 This Standard shall be applied in accounting for intangible assets, except:

(a) intangible assets that are within the scope of another Standard;

(b) financial assets, as defined in IAS 32 *Financial Instruments: Presentation*;

(c) the recognition and measurement of exploration and evaluation assets (see IFRS 6 *Exploration for and Evaluation of Mineral Resources*); and

(d) expenditure on the development and extraction of minerals, oil, natural gas and similar non-regenerative resources.

3 If another Standard prescribes the accounting for a specific type of intangible asset, an entity applies that Standard instead of this Standard. For example, this Standard does not apply to:

(a) intangible assets held by an entity for sale in the ordinary course of business (see IAS 2 *Inventories* and IAS 11 *Construction Contracts*).

(b) deferred tax assets (see IAS 12 *Income Taxes*).

(c) leases that are within the scope of IAS 17 *Leases*.

(d) assets arising from employee benefits (see IAS 19 *Employee Benefits*).

(e) financial assets as defined in IAS 32. The recognition and measurement of some financial assets are covered by IFRS 10 *Consolidated Financial Statements*, IAS 27 *Separate Financial Statements* and IAS 28 *Investments in Associates and Joint Ventures*.

(f) goodwill acquired in a business combination (see IFRS 3 *Business Combinations*).

(g) deferred acquisition costs, and intangible assets, arising from an insurer's contractual rights under insurance contracts within the scope of IFRS 4 *Insurance Contracts*. IFRS 4 sets out specific disclosure requirements for those deferred acquisition costs but not for those intangible assets. Therefore, the disclosure requirements in this Standard apply to those intangible assets.

(h) non-current intangible assets classified as held for sale (or included in a disposal group that is classified as held for sale) in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*.

Amendment: Paragraph 3 was amended in June 2014 by IFRS 15 *Revenue from Contracts with Customers*, which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2017. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

3 If another Standard prescribes the accounting for a specific type of intangible asset, an entity applies that Standard instead of this Standard. For example, this Standard does not apply to:

(a) intangible assets held by an entity for sale in the ordinary course of business (see IAS 2 *Inventories* ~~and IAS 11 *Construction Contracts*~~).

(b) ...

(i) assets arising from contracts with customers that are recognised in accordance with IFRS 15 *Revenue from Contracts with Customers.*

...

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2017. An entity shall apply these amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

4 Some intangible assets may be contained in or on a physical substance such as a compact disc (in the case of computer software), legal documentation (in the case of a licence or patent) or film. In determining whether an asset that incorporates both intangible and tangible elements should be treated under IAS 16 *Property, Plant and Equipment* or as an intangible asset under this Standard, an entity uses judgement to assess which element is more significant. For example, computer software for a computer-controlled machine tool that cannot operate without that specific software is an integral part of the related hardware and it is treated as property, plant and equipment. The same applies to the operating system of a computer. When the software is not an integral part of the related hardware, computer software is treated as an intangible asset.

5 This Standard applies to, among other things, expenditure on advertising, training, start-up, research and development activities. Research and development activities are directed to the development of knowledge. Therefore, although these activities may result in an asset with physical substance (eg a prototype), the physical element of the asset is secondary to its intangible component, ie the knowledge embodied in it.

6 In the case of a finance lease, the underlying asset may be either tangible or intangible. After initial recognition, a lessee accounts for an intangible asset held under a finance lease in accordance with this Standard. Rights under licensing agreements for items such as motion picture films, video recordings, plays, manuscripts, patents and copyrights are excluded from the scope of IAS 17 and are within the scope of this Standard.

7 Exclusions from the scope of a Standard may occur if activities or transactions are so specialised that they give rise to accounting issues that may need to be dealt with in a different way. Such issues arise in the accounting for expenditure on the exploration for, or development and extraction of, oil, gas and mineral deposits in extractive industries and in the case of insurance contracts. Therefore, this Standard does not apply to expenditure on such activities and contracts. However, this Standard applies to other intangible assets used (such as computer software), and other expenditure incurred (such as start-up costs), in extractive industries or by insurers.

Definitions

8 The following terms are used in this Standard with the meanings specified:

***Amortisation* is the systematic allocation of the depreciable amount of an**

intangible asset over its useful life.

An *asset* is a resource:

(a) controlled by an entity as a result of past events; and

(b) from which future economic benefits are expected to flow to the entity.

Carrying amount is the amount at which an asset is recognised in the statement of financial position after deducting any accumulated amortisation and accumulated impairment losses thereon.

Cost is the amount of cash or cash equivalents paid or the fair value of other consideration given to acquire an asset at the time of its acquisition or construction, or, when applicable, the amount attributed to that asset when initially recognised in accordance with the specific requirements of other IFRSs, eg IFRS 2 *Share-based Payment*.

Depreciable amount is the cost of an asset, or other amount substituted for cost, less its residual value.

Development is the application of research findings or other knowledge to a plan or design for the production of new or substantially improved materials, devices, products, processes, systems or services before the start of commercial production or use.

Entity-specific value is the present value of the cash flows an entity expects to arise from the continuing use of an asset and from its disposal at the end of its useful life or expects to incur when settling a liability.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. (See IFRS 13 *Fair Value Measurement*.)

An *impairment loss* is the amount by which the carrying amount of an asset exceeds its recoverable amount.

An *intangible asset* is an identifiable non-monetary asset without physical substance.

Monetary assets are money held and assets to be received in fixed or determinable amounts of money.

Research is original and planned investigation undertaken with the prospect of gaining new scientific or technical knowledge and understanding.

The *residual value* of an intangible asset is the estimated amount that an entity would currently obtain from disposal of the asset, after deducting the estimated costs of disposal, if the asset were already of the age and in the condition expected at the end of its useful life.

Useful life is:

(a) the period over which an asset is expected to be available for use by an entity; or

(b) the number of production or similar units expected to be obtained from the asset by an entity.

Intangible assets

9 Entities frequently expend resources, or incur liabilities, on the acquisition, development, maintenance or enhancement of intangible resources such as scientific or technical knowledge, design and implementation of new processes or systems, licences, intellectual property, market knowledge and trademarks (including brand names and publishing titles). Common examples of items encompassed by these broad headings are computer software, patents, copyrights, motion picture films, customer lists, mortgage servicing rights, fishing licences, import quotas, franchises, customer or supplier relationships, customer loyalty, market share and marketing rights.

10 Not all the items described in paragraph 9 meet the definition of an intangible asset, ie identifiability, control over a resource and existence of future economic benefits. If an item within the scope of this Standard does not meet the definition of an intangible asset, expenditure to acquire it or generate it internally is recognised as an expense when it is incurred. However, if the item is acquired in a business combination, it forms part of the goodwill recognised at the acquisition date (see paragraph 68).

Identifiability

11 The definition of an intangible asset requires an intangible asset to be identifiable to distinguish it from goodwill. Goodwill recognised in a business combination is an asset representing the future economic benefits arising from other assets acquired in a business combination that are not individually identified and separately recognised. The future economic benefits may result from synergy between the identifiable assets acquired or from assets that, individually, do not qualify for recognition in the financial statements.

12 An asset is identifiable if it either:

(a) is separable, ie is capable of being separated or divided from the entity and sold, transferred, licensed, rented or exchanged, either individually or together with a related contract, identifiable asset or liability, regardless of whether the entity intends to do so; or

(b) arises from contractual or other legal rights, regardless of whether those rights are transferable or separable from the entity or from other rights and obligations.

Control

13 An entity controls an asset if the entity has the power to obtain the future economic benefits flowing from the underlying resource and to restrict the access of others to those benefits. The capacity of an entity to control the future economic benefits from an intangible asset would normally stem from legal rights that are enforceable in a court of law. In the absence of legal rights, it is more difficult to demonstrate control. However, legal enforceability of a right is not a necessary condition for control because an entity may be able to control the future economic benefits in some other way.

14 Market and technical knowledge may give rise to future economic benefits. An entity controls those benefits if, for example, the knowledge is protected by legal rights such as copyrights, a restraint of trade agreement (where permitted) or by a legal duty on employees to maintain confidentiality.

15 An entity may have a team of skilled staff and may be able to identify incremental staff skills leading to future economic benefits from training. The entity may also expect that the staff will continue to make their skills available to the entity. However, an entity usually has insufficient control over the expected future economic benefits arising from a team of skilled staff and from training for these items to meet the definition of an intangible asset. For a similar reason, specific management or technical talent is unlikely to meet the definition of an intangible asset, unless it is protected by legal rights to use it and to obtain the future economic benefits expected from it, and it also meets the other parts of the definition.

16 An entity may have a portfolio of customers or a market share and expect that, because of its efforts in building customer relationships and loyalty, the customers will continue to trade with the entity. However, in the absence of legal rights to protect, or other ways to control, the relationships with customers or the loyalty of the customers to the entity, the entity usually has insufficient control over the expected economic benefits from customer relationships and loyalty for such items (eg portfolio of customers, market shares, customer relationships and customer loyalty) to meet the definition of intangible assets. In the absence of legal rights to protect customer relationships, exchange transactions for the same or similar non-contractual customer relationships (other than as part of a business combination) provide evidence that the entity is nonetheless able to control the expected future economic benefits flowing from the customer relationships. Because such exchange transactions also provide evidence that the customer relationships are separable, those customer relationships meet the definition of an intangible asset.

Future economic benefits

17 The future economic benefits flowing from an intangible asset may include revenue from the sale of products or services, cost savings, or other benefits resulting from the use of the asset by the entity. For example, the use of intellectual property in a production process may reduce future production costs rather than increase future revenues.

Recognition and measurement

18 The recognition of an item as an intangible asset requires an entity to demonstrate that the item meets:

(a) the definition of an intangible asset (see paragraphs 8–17); and

(b) the recognition criteria (see paragraphs 21–23).

This requirement applies to costs incurred initially to acquire or internally generate an intangible asset and those incurred subsequently to add to, replace part of, or service it.

19 Paragraphs 25–32 deal with the application of the recognition criteria to separately acquired intangible assets, and paragraphs 33–43 deal with their application to intangible assets acquired in a business combination. Paragraph 44 deals with the initial measurement of intangible assets acquired by way of a government grant, paragraphs 45–47 with exchanges of intangible assets, and paragraphs 48–50 with the treatment of internally generated goodwill. Paragraphs 51–67 deal with the initial recognition and measurement of internally generated intangible assets.

20 The nature of intangible assets is such that, in many cases, there are no additions to such an asset or replacements of part of it. Accordingly, most subsequent

expenditures are likely to maintain the expected future economic benefits embodied in an existing intangible asset rather than meet the definition of an intangible asset and the recognition criteria in this Standard. In addition, it is often difficult to attribute subsequent expenditure directly to a particular intangible asset rather than to the business as a whole. Therefore, only rarely will subsequent expenditure—expenditure incurred after the initial recognition of an acquired intangible asset or after completion of an internally generated intangible asset—be recognised in the carrying amount of an asset. Consistently with paragraph 63, subsequent expenditure on brands, mastheads, publishing titles, customer lists and items similar in substance (whether externally acquired or internally generated) is always recognised in profit or loss as incurred. This is because such expenditure cannot be distinguished from expenditure to develop the business as a whole.

21 An intangible asset shall be recognised if, and only if:

- **(a) it is probable that the expected future economic benefits that are attributable to the asset will flow to the entity; and**
- **(b) the cost of the asset can be measured reliably.**

22 An entity shall assess the probability of expected future economic benefits using reasonable and supportable assumptions that represent management's best estimate of the set of economic conditions that will exist over the useful life of the asset.

23 An entity uses judgement to assess the degree of certainty attached to the flow of future economic benefits that are attributable to the use of the asset on the basis of the evidence available at the time of initial recognition, giving greater weight to external evidence.

24 An intangible asset shall be measured initially at cost.

Separate acquisition

25 Normally, the price an entity pays to acquire separately an intangible asset will reflect expectations about the probability that the expected future economic benefits embodied in the asset will flow to the entity. In other words, the entity expects there to be an inflow of economic benefits, even if there is uncertainty about the timing or the amount of the inflow. Therefore, the probability recognition criterion in paragraph 21(a) is always considered to be satisfied for separately acquired intangible assets.

26 In addition, the cost of a separately acquired intangible asset can usually be measured reliably. This is particularly so when the purchase consideration is in the form of cash or other monetary assets.

27 The cost of a separately acquired intangible asset comprises:

- (a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates; and
- (b) any directly attributable cost of preparing the asset for its intended use.

28 Examples of directly attributable costs are:

- (a) costs of employee benefits (as defined in IAS 19) arising directly from bringing the asset to its working condition;

(b) professional fees arising directly from bringing the asset to its working condition; and

(c) costs of testing whether the asset is functioning properly.

29 Examples of expenditures that are not part of the cost of an intangible asset are:

(a) costs of introducing a new product or service (including costs of advertising and promotional activities);

(b) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and

(c) administration and other general overhead costs.

30 Recognition of costs in the carrying amount of an intangible asset ceases when the asset is in the condition necessary for it to be capable of operating in the manner intended by management. Therefore, costs incurred in using or redeploying an intangible asset are not included in the carrying amount of that asset. For example, the following costs are not included in the carrying amount of an intangible asset:

(a) costs incurred while an asset capable of operating in the manner intended by management has yet to be brought into use; and

(b) initial operating losses, such as those incurred while demand for the asset's output builds up.

31 Some operations occur in connection with the development of an intangible asset, but are not necessary to bring the asset to the condition necessary for it to be capable of operating in the manner intended by management. These incidental operations may occur before or during the development activities. Because incidental operations are not necessary to bring an asset to the condition necessary for it to be capable of operating in the manner intended by management, the income and related expenses of incidental operations are recognised immediately in profit or loss, and included in their respective classifications of income and expense.

32 If payment for an intangible asset is deferred beyond normal credit terms, its cost is the cash price equivalent. The difference between this amount and the total payments is recognised as interest expense over the period of credit unless it is capitalised in accordance with IAS 23 *Borrowing Costs*.

Acquisition as part of a business combination

33 In accordance with IFRS 3 *Business Combinations*, if an intangible asset is acquired in a business combination, the cost of that intangible asset is its fair value at the acquisition date. The fair value of an intangible asset will reflect market participants' expectations at the acquisition date about the probability that the expected future economic benefits embodied in the asset will flow to the entity. In other words, the entity expects there to be an inflow of economic benefits, even if there is uncertainty about the timing or the amount of the inflow. Therefore, the probability recognition criterion in paragraph 21(a) is always considered to be satisfied for intangible assets acquired in business combinations. If an asset acquired in a business combination is separable or arises from contractual or other legal rights, sufficient information exists to measure reliably the fair value of the asset. Thus, the reliable measurement criterion in paragraph 21(b) is always considered to be satisfied for intangible assets

acquired in business combinations.

34 In accordance with this Standard and IFRS 3 (as revised in 2008), an acquirer recognises at the acquisition date, separately from goodwill, an intangible asset of the acquiree, irrespective of whether the asset had been recognised by the acquiree before the business combination. This means that the acquirer recognises as an asset separately from goodwill an in-process research and development project of the acquiree if the project meets the definition of an intangible asset. An acquiree's in-process research and development project meets the definition of an intangible asset when it:

(a) meets the definition of an asset; and

(b) is identifiable, ie is separable or arises from contractual or other legal rights.

Intangible asset acquired in a business combination

35 If an intangible asset acquired in a business combination is separable or arises from contractual or other legal rights, sufficient information exists to measure reliably the fair value of the asset. When, for the estimates used to measure an intangible asset's fair value, there is a range of possible outcomes with different probabilities, that uncertainty enters into the measurement of the asset's fair value.

36 An intangible asset acquired in a business combination might be separable, but only together with a related contract, identifiable asset or liability. In such cases, the acquirer recognises the intangible asset separately from goodwill, but together with the related item.

37 The acquirer may recognise a group of complementary intangible assets as a single asset provided the individual assets have similar useful lives. For example, the terms 'brand' and 'brand name' are often used as synonyms for trademarks and other marks. However, the former are general marketing terms that are typically used to refer to a group of complementary assets such as a trademark (or service mark) and its related trade name, formulas, recipes and technological expertise.

38–41 [Deleted]

Subsequent expenditure on an acquired in-process research and development project

42 Research or development expenditure that:

(a) relates to an in-process research or development project acquired separately or in a business combination and recognised as an intangible asset; and

(b) is incurred after the acquisition of that project

shall be accounted for in accordance with paragraphs 54–62.

43 Applying the requirements in paragraphs 54–62 means that subsequent expenditure on an in-process research or development project acquired separately or in a business combination and recognised as an intangible asset is:

(a) recognised as an expense when incurred if it is research expenditure;

(b) recognised as an expense when incurred if it is development expenditure that does not satisfy the criteria for recognition as an intangible asset in paragraph 57; and

(c) added to the carrying amount of the acquired in-process research or development project if it is development expenditure that satisfies the recognition criteria in paragraph 57.

Acquisition by way of a government grant

44 In some cases, an intangible asset may be acquired free of charge, or for nominal consideration, by way of a government grant. This may happen when a government transfers or allocates to an entity intangible assets such as airport landing rights, licences to operate radio or television stations, import licences or quotas or rights to access other restricted resources. In accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance*, an entity may choose to recognise both the intangible asset and the grant initially at fair value. If an entity chooses not to recognise the asset initially at fair value, the entity recognises the asset initially at a nominal amount (the other treatment permitted by IAS 20) plus any expenditure that is directly attributable to preparing the asset for its intended use.

Exchanges of assets

45 One or more intangible assets may be acquired in exchange for a non-monetary asset or assets, or a combination of monetary and non-monetary assets. The following discussion refers simply to an exchange of one non-monetary asset for another, but it also applies to all exchanges described in the preceding sentence. The cost of such an intangible asset is measured at fair value unless (a) the exchange transaction lacks commercial substance or (b) the fair value of neither the asset received nor the asset given up is reliably measurable. The acquired asset is measured in this way even if an entity cannot immediately derecognise the asset given up. If the acquired asset is not measured at fair value, its cost is measured at the carrying amount of the asset given up.

46 An entity determines whether an exchange transaction has commercial substance by considering the extent to which its future cash flows are expected to change as a result of the transaction. An exchange transaction has commercial substance if:

(a) the configuration (ie risk, timing and amount) of the cash flows of the asset received differs from the configuration of the cash flows of the asset transferred; or

(b) the entity-specific value of the portion of the entity's operations affected by the transaction changes as a result of the exchange; and

(c) the difference in (a) or (b) is significant relative to the fair value of the assets exchanged.

For the purpose of determining whether an exchange transaction has commercial substance, the entity-specific value of the portion of the entity's operations affected by the transaction shall reflect post-tax cash flows. The result of these analyses may be clear without an entity having to perform detailed calculations.

47 Paragraph 21(b) specifies that a condition for the recognition of an intangible asset is that the cost of the asset can be measured reliably. The fair value of an intangible

asset is reliably measurable if (a) the variability in the range of reasonable fair value measurements is not significant for that asset or (b) the probabilities of the various estimates within the range can be reasonably assessed and used when measuring fair value. If an entity is able to measure reliably the fair value of either the asset received or the asset given up, then the fair value of the asset given up is used to measure cost unless the fair value of the asset received is more clearly evident.

Internally generated goodwill

48 Internally generated goodwill shall not be recognised as an asset.

49 In some cases, expenditure is incurred to generate future economic benefits, but it does not result in the creation of an intangible asset that meets the recognition criteria in this Standard. Such expenditure is often described as contributing to internally generated goodwill. Internally generated goodwill is not recognised as an asset because it is not an identifiable resource (ie it is not separable nor does it arise from contractual or other legal rights) controlled by the entity that can be measured reliably at cost.

50 Differences between the fair value of an entity and the carrying amount of its identifiable net assets at any time may capture a range of factors that affect the fair value of the entity. However, such differences do not represent the cost of intangible assets controlled by the entity.

Internally generated intangible assets

51 It is sometimes difficult to assess whether an internally generated intangible asset qualifies for recognition because of problems in:

(a) identifying whether and when there is an identifiable asset that will generate expected future economic benefits; and

(b) determining the cost of the asset reliably. In some cases, the cost of generating an intangible asset internally cannot be distinguished from the cost of maintaining or enhancing the entity's internally generated goodwill or of running day-to-day operations.

Therefore, in addition to complying with the general requirements for the recognition and initial measurement of an intangible asset, an entity applies the requirements and guidance in paragraphs 52–67 to all internally generated intangible assets.

52 To assess whether an internally generated intangible asset meets the criteria for recognition, an entity classifies the generation of the asset into:

(a) a research phase; and

(b) a development phase.

Although the terms 'research' and 'development' are defined, the terms 'research phase' and 'development phase' have a broader meaning for the purpose of this Standard.

53 If an entity cannot distinguish the research phase from the development phase of an internal project to create an intangible asset, the entity treats the expenditure on that project as if it were incurred in the research phase only.

Research phase

54 No intangible asset arising from research (or from the research phase of an internal project) shall be recognised. Expenditure on research (or on the research phase of an internal project) shall be recognised as an expense when it is incurred.

55 In the research phase of an internal project, an entity cannot demonstrate that an intangible asset exists that will generate probable future economic benefits. Therefore, this expenditure is recognised as an expense when it is incurred.

56 Examples of research activities are:

(a) activities aimed at obtaining new knowledge;

(b) the search for, evaluation and final selection of, applications of research findings or other knowledge;

(c) the search for alternatives for materials, devices, products, processes, systems or services; and

(d) the formulation, design, evaluation and final selection of possible alternatives for new or improved materials, devices, products, processes, systems or services.

Development phase

57 An intangible asset arising from development (or from the development phase of an internal project) shall be recognised if, and only if, an entity can demonstrate all of the following:

(a) the technical feasibility of completing the intangible asset so that it will be available for use or sale.

(b) its intention to complete the intangible asset and use or sell it.

(c) its ability to use or sell the intangible asset.

(d) how the intangible asset will generate probable future economic benefits. Among other things, the entity can demonstrate the existence of a market for the output of the intangible asset or the intangible asset itself or, if it is to be used internally, the usefulness of the intangible asset.

(e) the availability of adequate technical, financial and other resources to complete the development and to use or sell the intangible asset.

(f) its ability to measure reliably the expenditure attributable to the intangible asset during its development.

58 In the development phase of an internal project, an entity can, in some instances, identify an intangible asset and demonstrate that the asset will generate probable future economic benefits. This is because the development phase of a project is further advanced than the research phase.

59 Examples of development activities are:

(a) the design, construction and testing of pre-production or pre-use prototypes and models;

(b) the design of tools, jigs, moulds and dies involving new technology;

(c) the design, construction and operation of a pilot plant that is not of a scale economically feasible for commercial production; and

(d) the design, construction and testing of a chosen alternative for new or improved materials, devices, products, processes, systems or services.

60 To demonstrate how an intangible asset will generate probable future economic benefits, an entity assesses the future economic benefits to be received from the asset using the principles in IAS 36 *Impairment of Assets*. If the asset will generate economic benefits only in combination with other assets, the entity applies the concept of cash-generating units in IAS 36.

61 Availability of resources to complete, use and obtain the benefits from an intangible asset can be demonstrated by, for example, a business plan showing the technical, financial and other resources needed and the entity's ability to secure those resources. In some cases, an entity demonstrates the availability of external finance by obtaining a lender's indication of its willingness to fund the plan.

62 An entity's costing systems can often measure reliably the cost of generating an intangible asset internally, such as salary and other expenditure incurred in securing copyrights or licences or developing computer software.

63 Internally generated brands, mastheads, publishing titles, customer lists and items similar in substance shall not be recognised as intangible assets.

64 Expenditure on internally generated brands, mastheads, publishing titles, customer lists and items similar in substance cannot be distinguished from the cost of developing the business as a whole. Therefore, such items are not recognised as intangible assets.

Cost of an internally generated intangible asset

65 The cost of an internally generated intangible asset for the purpose of paragraph 24 is the sum of expenditure incurred from the date when the intangible asset first meets the recognition criteria in paragraphs 21, 22 and 57. Paragraph 71 prohibits reinstatement of expenditure previously recognised as an expense.

66 The cost of an internally generated intangible asset comprises all directly attributable costs necessary to create, produce, and prepare the asset to be capable of operating in the manner intended by management. Examples of directly attributable costs are:

(a) costs of materials and services used or consumed in generating the intangible asset;

(b) costs of employee benefits (as defined in IAS 19) arising from the generation of the intangible asset;

(c) fees to register a legal right; and

(d) amortisation of patents and licences that are used to generate the intangible asset.

IAS 23 specifies criteria for the recognition of interest as an element of the cost of an internally generated intangible asset.

67 The following are not components of the cost of an internally generated intangible asset:

(a) selling, administrative and other general overhead expenditure unless this expenditure can be directly attributed to preparing the asset for use;

(b) identified inefficiencies and initial operating losses incurred before the asset achieves planned performance; and

(c) expenditure on training staff to operate the asset.

Example illustrating paragraph 65

An entity is developing a new production process. During 20X5, expenditure incurred was CU1,000,[a] of which CU900 was incurred before 1 December 20X5 and CU100 was incurred between 1 December 20X5 and 31 December 20X5. The entity is able to demonstrate that, at 1 December 20X5, the production process met the criteria for recognition as an intangible asset. The recoverable amount of the know-how embodied in the process (including future cash outflows to complete the process before it is available for use) is estimated to be CU500.

At the end of 20X5, the production process is recognised as an intangible asset at a cost of CU100 (expenditure incurred since the date when the recognition criteria were met, ie 1 December 20X5). The CU900 expenditure incurred before 1 December 20X5 is recognised as an expense because the recognition criteria were not met until 1 December 20X5. This expenditure does not form part of the cost of the production process recognised in the statement of financial position.

During 20X6, expenditure incurred is CU2,000. At the end of 20X6, the recoverable amount of the know-how embodied in the process (including future cash outflows to complete the process before it is available for use) is estimated to be CU1,900.

At the end of 20X6, the cost of the production process is CU2,100 (CU100 expenditure recognised at the end of 20X5 plus CU2,000 expenditure recognised in 20X6). The entity recognises an impairment loss of CU200 to adjust the carrying amount of the process before impairment loss (CU2,100) to its recoverable amount (CU1,900). This impairment loss will be reversed in a subsequent period if the requirements for the reversal of an impairment loss in IAS 36 are met.

(a) In this Standard, monetary amounts are denominated in 'currency units (CU)'.

Recognition of an expense

68 Expenditure on an intangible item shall be recognised as an expense when it is incurred unless:

(a) it forms part of the cost of an intangible asset that meets the recognition criteria (see paragraphs 18–67); or

(b) the item is acquired in a business combination and cannot be recognised as an intangible asset. If this is the case, it forms part of the amount recognised as goodwill at the acquisition date (see IFRS 3).

69 In some cases, expenditure is incurred to provide future economic benefits to an entity, but no intangible asset or other asset is acquired or created that can be recognised.

In the case of the supply of goods, the entity recognises such expenditure as an expense when it has a right to access those goods. In the case of the supply of services, the entity recognises the expenditure as an expense when it receives the services. For example, expenditure on research is recognised as an expense when it is incurred (see paragraph 54), except when it is acquired as part of a business combination. Other examples of expenditure that is recognised as an expense when it is incurred include:

(a) expenditure on start-up activities (ie start-up costs), unless this expenditure is included in the cost of an item of property, plant and equipment in accordance with IAS 16. Start-up costs may consist of establishment costs such as legal and secretarial costs incurred in establishing a legal entity, expenditure to open a new facility or business (ie pre-opening costs) or expenditures for starting new operations or launching new products or processes (ie pre-operating costs).

(b) expenditure on training activities.

(c) expenditure on advertising and promotional activities (including mail order catalogues).

(d) expenditure on relocating or reorganising part or all of an entity.

69A An entity has a right to access goods when it owns them. Similarly, it has a right to access goods when they have been constructed by a supplier in accordance with the terms of a supply contract and the entity could demand delivery of them in return for payment. Services are received when they are performed by a supplier in accordance with a contract to deliver them to the entity and not when the entity uses them to deliver another service, for example, to deliver an advertisement to customers.

70 Paragraph 68 does not preclude an entity from recognising a prepayment as an asset when payment for goods has been made in advance of the entity obtaining a right to access those goods. Similarly, paragraph 68 does not preclude an entity from recognising a prepayment as an asset when payment for services has been made in advance of the entity receiving those services.

Past expenses not to be recognised as an asset

71 Expenditure on an intangible item that was initially recognised as an expense shall not be recognised as part of the cost of an intangible asset at a later date.

Measurement after recognition

72 An entity shall choose either the cost model in paragraph 74 or the revaluation model in paragraph 75 as its accounting policy. If an intangible asset is accounted for using the revaluation model, all the other assets in its class shall also be accounted for using the same model, unless there is no active market for those assets.

73 A class of intangible assets is a grouping of assets of a similar nature and use in an entity's operations. The items within a class of intangible assets are revalued simultaneously to avoid selective revaluation of assets and the reporting of amounts in the financial statements representing a mixture of costs and values as at different dates.

Cost model

74 After initial recognition, an intangible asset shall be carried at its cost less any accumulated amortisation and any accumulated impairment losses.

Revaluation model

75 After initial recognition, an intangible asset shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated amortisation and any subsequent accumulated impairment losses. For the purpose of revaluations under this Standard, fair value shall be measured by reference to an active market. Revaluations shall be made with such regularity that at the end of the reporting period the carrying amount of the asset does not differ materially from its fair value.

76 The revaluation model does not allow:

(a) the revaluation of intangible assets that have not previously been recognised as assets; or

(b) the initial recognition of intangible assets at amounts other than cost.

77 The revaluation model is applied after an asset has been initially recognised at cost. However, if only part of the cost of an intangible asset is recognised as an asset because the asset did not meet the criteria for recognition until part of the way through the process (see paragraph 65), the revaluation model may be applied to the whole of that asset. Also, the revaluation model may be applied to an intangible asset that was received by way of a government grant and recognised at a nominal amount (see paragraph 44).

78 It is uncommon for an active market to exist for an intangible asset, although this may happen. For example, in some jurisdictions, an active market may exist for freely transferable taxi licences, fishing licences or production quotas. However, an active market cannot exist for brands, newspaper mastheads, music and film publishing rights, patents or trademarks, because each such asset is unique. Also, although intangible assets are bought and sold, contracts are negotiated between individual buyers and sellers, and transactions are relatively infrequent. For these reasons, the price paid for one asset may not provide sufficient evidence of the fair value of another. Moreover, prices are often not available to the public.

79 The frequency of revaluations depends on the volatility of the fair values of the intangible assets being revalued. If the fair value of a revalued asset differs materially from its carrying amount, a further revaluation is necessary. Some intangible assets may experience significant and volatile movements in fair value, thus necessitating annual revaluation. Such frequent revaluations are unnecessary for intangible assets with only insignificant movements in fair value.

80 When an intangible asset is revalued, the carrying amount of that asset is adjusted to the revalued amount. At the date of the revaluation, the asset is treated in one of the following ways:

(a) the gross carrying amount is adjusted in a manner that is consistent with the revaluation of the carrying amount of the asset. For example, the gross carrying amount may be restated by reference to observable market data or it may be restated proportionately to the change in the carrying amount.

The accumulated amortisation at the date of the revaluation is adjusted to equal the difference between the gross carrying amount and the carrying amount of the asset after taking into account accumulated impairment losses; or

(b) the accumulated amortisation is eliminated against the gross carrying amount of the asset.

The amount of the adjustment of accumulated amortisation forms part of the increase or decrease in the carrying amount that is accounted for in accordance with paragraphs 85 and 86.

81 If an intangible asset in a class of revalued intangible assets cannot be revalued because there is no active market for this asset, the asset shall be carried at its cost less any accumulated amortisation and impairment losses.

82 If the fair value of a revalued intangible asset can no longer be measured by reference to an active market, the carrying amount of the asset shall be its revalued amount at the date of the last revaluation by reference to the active market less any subsequent accumulated amortisation and any subsequent accumulated impairment losses.

83 The fact that an active market no longer exists for a revalued intangible asset may indicate that the asset may be impaired and that it needs to be tested in accordance with IAS 36.

84 If the fair value of the asset can be measured by reference to an active market at a subsequent measurement date, the revaluation model is applied from that date.

85 If an intangible asset's carrying amount is increased as a result of a revaluation, the increase shall be recognised in other comprehensive income and accumulated in equity under the heading of revaluation surplus. However, the increase shall be recognised in profit or loss to the extent that it reverses a revaluation decrease of the same asset previously recognised in profit or loss.

86 If an intangible asset's carrying amount is decreased as a result of a revaluation, the decrease shall be recognised in profit or loss. However, the decrease shall be recognised in other comprehensive income to the extent of any credit balance in the revaluation surplus in respect of that asset. The decrease recognised in other comprehensive income reduces the amount accumulated in equity under the heading of revaluation surplus.

87 The cumulative revaluation surplus included in equity may be transferred directly to retained earnings when the surplus is realised. The whole surplus may be realised on the retirement or disposal of the asset. However, some of the surplus may be realised as the asset is used by the entity; in such a case, the amount of the surplus realised is the difference between amortisation based on the revalued carrying amount of the asset and amortisation that would have been recognised based on the asset's historical cost. The transfer from revaluation surplus to retained earnings is not made through profit or loss.

Useful life

88 An entity shall assess whether the useful life of an intangible asset is finite or indefinite and, if finite, the length of, or number of production or similar units

constituting, that useful life. An intangible asset shall be regarded by the entity as having an indefinite useful life when, based on an analysis of all of the relevant factors, there is no foreseeable limit to the period over which the asset is expected to generate net cash inflows for the entity.

89 The accounting for an intangible asset is based on its useful life. An intangible asset with a finite useful life is amortised (see paragraphs 97–106), and an intangible asset with an indefinite useful life is not (see paragraphs 107–110). The Illustrative Examples accompanying this Standard illustrate the determination of useful life for different intangible assets, and the subsequent accounting for those assets based on the useful life determinations.

90 Many factors are considered in determining the useful life of an intangible asset, including:

(a) the expected usage of the asset by the entity and whether the asset could be managed efficiently by another management team;

(b) typical product life cycles for the asset and public information on estimates of useful lives of similar assets that are used in a similar way;

(c) technical, technological, commercial or other types of obsolescence;

(d) the stability of the industry in which the asset operates and changes in the market demand for the products or services output from the asset;

(e) expected actions by competitors or potential competitors;

(f) the level of maintenance expenditure required to obtain the expected future economic benefits from the asset and the entity's ability and intention to reach such a level;

(g) the period of control over the asset and legal or similar limits on the use of the asset, such as the expiry dates of related leases; and

(h) whether the useful life of the asset is dependent on the useful life of other assets of the entity.

91 The term 'indefinite' does not mean 'infinite'. The useful life of an intangible asset reflects only that level of future maintenance expenditure required to maintain the asset at its standard of performance assessed at the time of estimating the asset's useful life, and the entity's ability and intention to reach such a level. A conclusion that the useful life of an intangible asset is indefinite should not depend on planned future expenditure in excess of that required to maintain the asset at that standard of performance.

92 Given the history of rapid changes in technology, computer software and many other intangible assets are susceptible to technological obsolescence. Therefore, it is likely that their useful life is short.

Amendment: Paragraph 92 was amended in May 2014 by *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

92 Given the history of rapid changes in technology, computer software and many other intangible assets are susceptible to technological obsolescence. Therefore, it ~~is likely~~ will often be the case that their useful life is short. Expected future reductions in the selling price of an item that was produced using an intangible asset could indicate the expectation of technological or commercial obsolescence of the asset, which, in turn, might reflect a reduction of the future economic benefits embodied in the asset.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2016. An entity shall apply those amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

93 The useful life of an intangible asset may be very long or even indefinite. Uncertainty justifies estimating the useful life of an intangible asset on a prudent basis, but it does not justify choosing a life that is unrealistically short.

94 The useful life of an intangible asset that arises from contractual or other legal rights shall not exceed the period of the contractual or other legal rights, but may be shorter depending on the period over which the entity expects to use the asset. If the contractual or other legal rights are conveyed for a limited term that can be renewed, the useful life of the intangible asset shall include the renewal period(s) only if there is evidence to support renewal by the entity without significant cost. The useful life of a reacquired right recognised as an intangible asset in a business combination is the remaining contractual period of the contract in which the right was granted and shall not include renewal periods.

95 There may be both economic and legal factors influencing the useful life of an intangible asset. Economic factors determine the period over which future economic benefits will be received by the entity. Legal factors may restrict the period over which the entity controls access to these benefits. The useful life is the shorter of the periods determined by these factors.

96 Existence of the following factors, among others, indicates that an entity would be able to renew the contractual or other legal rights without significant cost:

(a) there is evidence, possibly based on experience, that the contractual or other legal rights will be renewed. If renewal is contingent upon the consent of a third party, this includes evidence that the third party will give its consent;

(b) there is evidence that any conditions necessary to obtain renewal will be satisfied; and

(c) the cost to the entity of renewal is not significant when compared with the future economic benefits expected to flow to the entity from renewal.

If the cost of renewal is significant when compared with the future economic benefits expected to flow to the entity from renewal, the 'renewal' cost represents, in substance, the cost to acquire a new intangible asset at the renewal date.

Intangible assets with finite useful lives

Amortisation period and amortisation method

97 **The depreciable amount of an intangible asset with a finite useful life shall be allocated on a systematic basis over its useful life. Amortisation shall begin when the asset is available for use, ie when it is in the location and condition necessary for it to be capable of operating in the manner intended by management. Amortisation shall cease at the earlier of the date that the asset is classified as held for sale (or included in a disposal group that is classified as held for sale) in accordance with IFRS 5 and the date that the asset is derecognised. The amortisation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. If that pattern cannot be determined reliably, the straight-line method shall be used. The amortisation charge for each period shall be recognised in profit or loss unless this or another Standard permits or requires it to be included in the carrying amount of another asset.**

98 A variety of amortisation methods can be used to allocate the depreciable amount of an asset on a systematic basis over its useful life. These methods include the straight-line method, the diminishing balance method and the unit of production method. The method used is selected on the basis of the expected pattern of consumption of the expected future economic benefits embodied in the asset and is applied consistently from period to period, unless there is a change in the expected pattern of consumption of those future economic benefits.

Amendment: Paragraph 98 was amended in May 2014 by *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

98 A variety of amortisation methods can be used to allocate the depreciable amount of an asset on a systematic basis over its useful life. These methods include the straight-line method, the diminishing balance method and the units of production method. The method used is selected on the basis of the expected pattern of consumption of the expected future economic benefits embodied in the asset and is applied consistently from period to period, unless there is a change in the expected pattern of consumption of those future economic benefits.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2016. An entity shall apply those amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

Amendment: Paragraph 98A was added in May 2014 by *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

98A There is a rebuttable presumption that an amortisation method that is based on the revenue generated by an activity that includes the use of an intangible asset is inappropriate. The revenue generated by an activity that includes the use of an intangible asset typically reflects factors that are not directly linked to the consumption of the economic benefits embodied in the intangible asset. For example, revenue is affected by other inputs and processes, selling activities and changes in sales volumes and prices. The price component of revenue may be affected by inflation, which has no bearing upon the way in which an asset is consumed. This presumption can be overcome only in the limited circumstances:

(a) in which the intangible asset is expressed as a measure of revenue, as described in paragraph 98C; or

(b) when it can be demonstrated that revenue and the consumption of the economic benefits of the intangible asset are highly correlated.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2016. An entity shall apply those amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

Amendment: Paragraph 98B was added in May 2014 by *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

98B In choosing an appropriate amortisation method in accordance with paragraph 98, an entity could determine the predominant limiting factor that is inherent in the intangible asset. For example, the contract that sets out the entity's rights over its use of an intangible asset might specify the entity's use of the intangible asset as a predetermined number of years (ie time), as a number of units produced or as a fixed total amount of revenue to be generated. Identification of such a predominant limiting factor could serve as the starting point for the identification of the appropriate basis of amortisation, but another basis may be applied if it more closely reflects the expected pattern of consumption of economic benefits.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2016. An entity shall apply those amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

Amendment: Paragraph 98C was added in May 2014 by *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

98C In the circumstance in which the predominant limiting factor that is inherent in an intangible asset is the achievement of a revenue threshold, the revenue to be generated can be an appropriate basis for amortisation. For example, an entity could acquire a concession to explore and extract gold from a gold mine. The expiry of the contract might be based on a fixed amount of total revenue to be generated from the extraction (for example, a contract may allow the extraction of gold from the mine until total cumulative revenue from the sale of gold reaches CU2 billion) and not be based on time or on the amount of gold extracted. In another example, the right to operate a toll road could be based on a fixed total amount of revenue to be generated from cumulative tolls charged (for example, a contract could allow operation of the toll road until the cumulative amount of tolls generated from operating the road reaches CU100 million). In the case in which revenue has been established as the predominant limiting factor in the contract for the use of the intangible asset, the revenue that is to be generated might be an appropriate basis for amortising the intangible asset, provided that the contract specifies a fixed total amount of revenue to be generated on which amortisation is to be determined.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2016. An entity shall apply those amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

99 Amortisation is usually recognised in profit or loss. However, sometimes the future economic benefits embodied in an asset are absorbed in producing other assets. In this case, the amortisation charge constitutes part of the cost of the other asset and is included in its carrying amount. For example, the amortisation of intangible assets used in a production process is included in the carrying amount of inventories (see IAS 2 *Inventories*).

Residual value

100 The residual value of an intangible asset with a finite useful life shall be assumed to be zero unless:

(a) there is a commitment by a third party to purchase the asset at the end of its useful life; or

(b) there is an active market (as defined in IFRS 13) for the asset and:

(i) residual value can be determined by reference to that market; and

(ii) it is probable that such a market will exist at the end of the asset's useful life.

101 The depreciable amount of an asset with a finite useful life is determined after deducting its residual value. A residual value other than zero implies that an entity expects to dispose of the intangible asset before the end of its economic life.

102 An estimate of an asset's residual value is based on the amount recoverable from disposal using prices prevailing at the date of the estimate for the sale of a similar asset that has reached the end of its useful life and has operated under conditions similar to those in which the asset will be used. The residual value is reviewed at least at each financial year-end. A change in the asset's residual value is accounted for as a change in an accounting estimate in accordance with IAS 8 *Accounting*

Policies, Changes in Accounting Estimates and Errors.

103 The residual value of an intangible asset may increase to an amount equal to or greater than the asset's carrying amount. If it does, the asset's amortisation charge is zero unless and until its residual value subsequently decreases to an amount below the asset's carrying amount.

Review of amortisation period and amortisation method

104 The amortisation period and the amortisation method for an intangible asset with a finite useful life shall be reviewed at least at each financial year-end. If the expected useful life of the asset is different from previous estimates, the amortisation period shall be changed accordingly. If there has been a change in the expected pattern of consumption of the future economic benefits embodied in the asset, the amortisation method shall be changed to reflect the changed pattern. Such changes shall be accounted for as changes in accounting estimates in accordance with IAS 8.

105 During the life of an intangible asset, it may become apparent that the estimate of its useful life is inappropriate. For example, the recognition of an impairment loss may indicate that the amortisation period needs to be changed.

106 Over time, the pattern of future economic benefits expected to flow to an entity from an intangible asset may change. For example, it may become apparent that a diminishing balance method of amortisation is appropriate rather than a straight-line method. Another example is if use of the rights represented by a licence is deferred pending action on other components of the business plan. In this case, economic benefits that flow from the asset may not be received until later periods.

Intangible assets with indefinite useful lives

107 An intangible asset with an indefinite useful life shall not be amortised.

108 In accordance with IAS 36, an entity is required to test an intangible asset with an indefinite useful life for impairment by comparing its recoverable amount with its carrying amount

(a) annually, and

(b) whenever there is an indication that the intangible asset may be impaired.

Review of useful life assessment

109 The useful life of an intangible asset that is not being amortised shall be reviewed each period to determine whether events and circumstances continue to support an indefinite useful life assessment for that asset. If they do not, the change in the useful life assessment from indefinite to finite shall be accounted for as a change in an accounting estimate in accordance with IAS 8.

110 In accordance with IAS 36, reassessing the useful life of an intangible asset as finite rather than indefinite is an indicator that the asset may be impaired. As a result, the entity tests the asset for impairment by comparing its recoverable amount, determined in accordance with IAS 36, with its carrying amount, and recognising any excess of the carrying amount over the recoverable amount as an impairment loss.

Recoverability of the carrying amount—impairment losses

111 To determine whether an intangible asset is impaired, an entity applies IAS 36. That Standard explains when and how an entity reviews the carrying amount of its assets, how it determines the recoverable amount of an asset and when it recognises or reverses an impairment loss.

Retirements and disposals

112 An intangible asset shall be derecognised:

(a) on disposal; or

(b) when no future economic benefits are expected from its use or disposal.

113 The gain or loss arising from the derecognition of an intangible asset shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset. It shall be recognised in profit or loss when the asset is derecognised (unless IAS 17 requires otherwise on a sale and leaseback.) Gains shall not be classified as revenue.

114 The disposal of an intangible asset may occur in a variety of ways (eg by sale, by entering into a finance lease, or by donation). In determining the date of disposal of such an asset, an entity applies the criteria in IAS 18 *Revenue* for recognising revenue from the sale of goods. IAS 17 applies to disposal by a sale and leaseback.

Amendment: Paragraph 114 was amended in June 2014 by IFRS 15 *Revenue from Contracts with Customers,* which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2017. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

114 The disposal of an intangible asset may occur in a variety of ways (eg by sale, by entering into a finance lease, or by donation). ~~In determining t~~The date of disposal of ~~such an asset, an entity applies the criteria in IAS 18 *Revenue* for recognising revenue from the sale of goods~~ an intangible asset is the date that the recipient obtains control of that asset in accordance with the requirements for determining when a performance obligation is satisfied in IFRS 15 *Revenue from Contracts with Customers*. IAS 17 applies to disposal by a sale and leaseback.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2017. An entity shall apply these amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

115 If in accordance with the recognition principle in paragraph 21 an entity recognises in the carrying amount of an asset the cost of a replacement for part of an intangible asset, then it derecognises the carrying amount of the replaced part. If it is not practicable for an entity to determine the carrying amount of the replaced part, it may use the cost of the replacement as an indication of what the cost of the replaced part was at the time it was acquired or internally generated.

115A In the case of a reacquired right in a business combination, if the right is subsequently reissued (sold) to a third party, the related carrying amount, if any, shall be used in determining the gain or loss on reissue.

116 The consideration receivable on disposal of an intangible asset is recognised initially at its fair value. If payment for the intangible asset is deferred, the consideration received is recognised initially at the cash price equivalent. The difference between the nominal amount of the consideration and the cash price equivalent is recognised as interest revenue in accordance with IAS 18 reflecting the effective yield on the receivable.

Amendment: Paragraph 116 was amended in June 2014 by IFRS 15 *Revenue from Contracts with Customers*, which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2017. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

116 The amount of consideration ~~receivable on disposal~~ to be included in the gain or loss arising from the derecognition of an intangible asset is ~~recognised initially at its fair value. If payment for the intangible asset is deferred, the consideration received is recognised initially at the cash price equivalent. The difference between the nominal amount of the consideration and the cash price equivalent is recognised as interest revenue in accordance with IAS 18 reflecting the effective yield on the receivable~~ determined in accordance with the requirements for determining the transaction price in paragraphs 47–72 of IFRS 15. Subsequent changes to the estimated amount of the consideration included in the gain or loss shall be accounted for in accordance with the requirements for changes in the transaction price in IFRS 15.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2017. An entity shall apply these amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

117 Amortisation of an intangible asset with a finite useful life does not cease when the intangible asset is no longer used, unless the asset has been fully depreciated or is classified as held for sale (or included in a disposal group that is classified as held for sale) in accordance with IFRS 5.

Disclosure

General

118 An entity shall disclose the following for each class of intangible assets, distinguishing between internally generated intangible assets and other intangible assets:

(a) whether the useful lives are indefinite or finite and, if finite, the useful lives or the amortisation rates used;

(b) the amortisation methods used for intangible assets with finite useful lives;

(c) the gross carrying amount and any accumulated amortisation (aggregated with accumulated impairment losses) at the beginning and end of the period;

(d) the line item(s) of the statement of comprehensive income in which any amortisation of intangible assets is included;

(e) a reconciliation of the carrying amount at the beginning and end of the period showing:

(i) additions, indicating separately those from internal development, those acquired separately, and those acquired through business combinations;

(ii) assets classified as held for sale or included in a disposal group classified as held for sale in accordance with IFRS 5 and other disposals;

(iii) increases or decreases during the period resulting from revaluations under paragraphs 75, 85 and 86 and from impairment losses recognised or reversed in other comprehensive income in accordance with IAS 36 (if any);

(iv) impairment losses recognised in profit or loss during the period in accordance with IAS 36 (if any);

(v) impairment losses reversed in profit or loss during the period in accordance with IAS 36 (if any);

(vi) any amortisation recognised during the period;

(vii) net exchange differences arising on the translation of the financial statements into the presentation currency, and on the translation of a foreign operation into the presentation currency of the entity; and

(viii) other changes in the carrying amount during the period.

119 A class of intangible assets is a grouping of assets of a similar nature and use in an entity's operations. Examples of separate classes may include:

(a) brand names;

(b) mastheads and publishing titles;

(c) computer software;

(d) licences and franchises;

(e) copyrights, patents and other industrial property rights, service and operating rights;

(f) recipes, formulae, models, designs and prototypes; and

(g) intangible assets under development.

The classes mentioned above are disaggregated (aggregated) into smaller (larger) classes if this results in more relevant information for the users of the financial statements.

120 An entity discloses information on impaired intangible assets in accordance with IAS 36 in addition to the information required by paragraph 118(e)(iii)–(v).

121 IAS 8 requires an entity to disclose the nature and amount of a change in an accounting estimate that has a material effect in the current period or is expected to have a material effect in subsequent periods. Such disclosure may arise from changes in:

(a) the assessment of an intangible asset's useful life;

(b) the amortisation method; or

(c) residual values.

122 An entity shall also disclose:

(a) for an intangible asset assessed as having an indefinite useful life, the carrying amount of that asset and the reasons supporting the assessment of an indefinite useful life. In giving these reasons, the entity shall describe the factor(s) that played a significant role in determining that the asset has an indefinite useful life.

(b) a description, the carrying amount and remaining amortisation period of any individual intangible asset that is material to the entity's financial statements.

(c) for intangible assets acquired by way of a government grant and initially recognised at fair value (see paragraph 44):

(i) the fair value initially recognised for these assets;

(ii) their carrying amount; and

(iii) whether they are measured after recognition under the cost model or the revaluation model.

(d) the existence and carrying amounts of intangible assets whose title is restricted and the carrying amounts of intangible assets pledged as security for liabilities.

(e) the amount of contractual commitments for the acquisition of intangible assets.

123 When an entity describes the factor(s) that played a significant role in determining that the useful life of an intangible asset is indefinite, the entity considers the list of factors in paragraph 90.

Intangible assets measured after recognition using the revaluation model

124 If intangible assets are accounted for at revalued amounts, an entity shall disclose the following:

(a) by class of intangible assets:

(i) the effective date of the revaluation;

(ii) the carrying amount of revalued intangible assets; and

(iii) the carrying amount that would have been recognised had the revalued class of intangible assets been measured after recognition using the cost model in paragraph 74; and

(b) the amount of the revaluation surplus that relates to intangible assets at the beginning and end of the period, indicating the changes during the period and any restrictions on the distribution of the balance to shareholders.

(c) [deleted]

125 It may be necessary to aggregate the classes of revalued assets into larger classes for disclosure purposes. However, classes are not aggregated if this would result in the combination of a class of intangible assets that includes amounts measured under both the cost and revaluation models.

Research and development expenditure

126 An entity shall disclose the aggregate amount of research and development expenditure recognised as an expense during the period.

127 Research and development expenditure comprises all expenditure that is directly attributable to research or development activities (see paragraphs 66 and 67 for guidance on the type of expenditure to be included for the purpose of the disclosure requirement in paragraph 126).

Other information

128 An entity is encouraged, but not required, to disclose the following information:

(a) a description of any fully amortised intangible asset that is still in use; and

(b) a brief description of significant intangible assets controlled by the entity but not recognised as assets because they did not meet the recognition criteria in this Standard or because they were acquired or generated before the version of IAS 38 *Intangible Assets* issued in 1998 was effective.

Transitional provisions and effective date

129 [Deleted]

130 An entity shall apply this Standard:

(a) to the accounting for intangible assets acquired in business combinations for which the agreement date is on or after 31 March 2004; and

(b) to the accounting for all other intangible assets prospectively from the beginning of the first annual period beginning on or after 31 March 2004. Thus, the entity shall not adjust the carrying amount of intangible assets recognised at that date. However, the entity shall, at that date, apply this Standard to reassess the useful lives of such intangible assets. If, as a result of that reassessment, the entity changes its assessment of the useful life of an asset, that change shall be accounted for as a change in an accounting estimate in accordance with IAS 8.

130A An entity shall apply the amendments in paragraph 2 for annual periods beginning on or after 1 January 2006. If an entity applies IFRS 6 for an earlier period, those amendments shall be applied for that earlier period.

130B IAS 1 *Presentation of Financial Statements* (as revised in 2007) amended the terminology used throughout IFRSs. In addition it amended paragraphs 85, 86 and 118(e)(iii). An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. If an entity applies IAS 1 (revised 2007) for an earlier period, the amendments shall be applied for that earlier period.

130C IFRS 3 (as revised in 2008) amended paragraphs 12, 33–35, 68, 69, 94 and 130, deleted paragraphs 38 and 129 and added paragraph 115A. *Improvements to IFRSs* issued in April 2009 amended paragraphs 36 and 37. An entity shall apply those amendments prospectively for annual periods beginning on or after 1 July 2009. Therefore, amounts recognised for intangible assets and goodwill in prior business combinations shall not be adjusted. If an entity applies IFRS 3 (revised 2008) for an earlier period, it shall apply the amendments for that earlier period and disclose that fact.

130D Paragraphs 69, 70 and 98 were amended and paragraph 69A was added by *Improvements to IFRSs* issued in May 2008. An entity shall apply those amendments for annual periods beginning on or after 1 January 2009. Earlier application is permitted. If an entity applies the amendments for an earlier period it shall disclose that fact.

130E [Deleted]

130F IFRS 10 and IFRS 11 *Joint Arrangements*, issued in May 2011, amended paragraph 3(e). An entity shall apply that amendment when it applies IFRS 10 and IFRS 11.

130G IFRS 13, issued in May 2011, amended paragraphs 8, 33, 47, 50, 75, 78, 82, 84, 100 and 124 and deleted paragraphs 39–41 and 130E. An entity shall apply those amendments when it applies IFRS 13.

130H *Annual Improvements to IFRSs 2010–2012 Cycle*, issued in December 2013, amended paragraph 80. An entity shall apply that amendment for annual periods beginning on or after 1 July 2014. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

130I An entity shall apply the amendment made by *Annual Improvements to IFRSs 2010–2012 Cycle* to all revaluations recognised in annual periods beginning on or after the date of initial application of that amendment and in the immediately preceding annual period. An entity may also present adjusted comparative information for any earlier periods presented, but it is not required to do so. If an entity presents unadjusted comparative information for any earlier periods, it shall clearly identify the information that has not been adjusted, state that it has been presented on a different basis and explain that basis.

Amendment: Paragraph 130J was added in May 2014 by *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

130J *Clarification of Acceptable Methods of Depreciation and Amortisation* (Amendments to IAS 16 and IAS 38), issued in May 2014, amended paragraphs 92 and 98 and added paragraphs 98A–98C. An entity shall apply those amendments prospectively for annual periods beginning on or after 1 January 2016. Earlier application is permitted. If an entity applies those amendments for an earlier period it shall disclose that fact.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2016. An entity shall apply those amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

Amendment: Paragraph 130K was added in June 2014 by IFRS 15 *Revenue from Contracts with Customers,* which amended IAS 38. An entity shall apply these amendments for annual periods beginning on or after 1 January 2017. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact. See **Application**. The amendment reads as follows:

130K IFRS 15 *Revenue from Contracts with Customers*, issued in May 2014, amended paragraphs 3, 114 and 116. An entity shall apply those amendments when it applies IFRS 15.

Application: Entities shall apply these amendments for annual periods beginning on or after 1 January 2017. An entity shall apply these amendments retrospectively in accordance with IAS 8. Earlier application is permitted. If an entity applies that amendment for an earlier period it shall disclose that fact.

Exchanges of similar assets

131 The requirement in paragraphs 129 and 130(b) to apply this Standard prospectively means that if an exchange of assets was measured before the effective date of this Standard on the basis of the carrying amount of the asset given up, the entity does not restate the carrying amount of the asset acquired to reflect its fair value at the acquisition date.

Early application

132 Entities to which paragraph 130 applies are encouraged to apply the requirements of this Standard before the effective dates specified in paragraph 130. However, if an entity applies this Standard before those effective dates, it also shall apply IFRS 3 and IAS 36 (as revised in 2004) at the same time.

Withdrawal of IAS 38 (issued 1998)

133 This Standard supersedes IAS 38 *Intangible Assets* (issued in 1998).

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6.7 Replacement, Relocation And Bypass Of Existing Facilities

6.7.1 A transmitter shall notify each customer that will be affected by the transmitter's plans to retire a connection facility, at least five years in advance of the effective date of the retirement. The transmitter shall give each affected customer the option of:

(a) providing its own replacement connection facility;

(b) connecting its facilities to the connection facility of another person; or

(c) requiring the transmitter to provide a replacement connection facility.

6.7.2 Where a transmitter's connection facility is retired, the transmitter shall not recover a capital contribution from a customer to replace that connection facility.

6.7.3 Where a customer requests the relocation of a transmitter's connection or network facility, the transmitter shall recover from that customer the cost of relocating that connection or network facility.

6.7.4 Where a transmitter's connection or network facility is relocated in the absence of a customer request, the transmitter shall bear the cost of relocating that connection or network facility.

6.7.5 **When a load customer provides its own connection facility to serve new load or transfers new load to the connection facility of another person, the transmitter shall not require bypass compensation from that customer.**

6.7.6 Subject to sections 6.7.2, 6.7.7 and 6.7.8, for all or a portion of existing load a load customer may bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person, **provided that the load customer compensates the transmitter.**

6.7.7 For the purposes of sections 6.7.6 and 11.2.1, but subject to section 6.7.8, the transmitter shall calculate bypass compensation by first multiplying the net book value of the bypassed connection facility, including a salvage credit and reasonable removal and environmental remediation costs, if applicable, by the bypassed capacity on the relevant connection facility. The transmitter shall then divide the resulting figure by the total normal supply capacity of the bypassed connection facility. For purposes of this calculation:

(a) the bypassed capacity on the relevant connection facility shall be equal to the difference between the customer's existing load on that connection facility at the time of bypass and the customer's average monthly peak load in the three-month period following the date on which bypass occurred; and

(b) the normal supply capacity of the bypassed connection facility shall be determined by the transmitter in accordance with the Board-approved procedure referred to in section 6.2.7.

6.7.8 Where an economic evaluation, including an economic evaluation referred to in section 6.3.9 or 6.3.17A, was conducted by a transmitter for a load customer in relation to a connection facility on the basis of a load forecast, a transmitter shall not, during the economic evaluation period to which the economic evaluation relates, require bypass compensation from a customer under section 6.7.6 in relation to any load that represents that customer's contracted capacity.

6.7.9 A transmitter should avoid overloading a connection facility above its total normal supply capacity. Where a connection facility has been overloaded, and a customer transfers the overload to its own connection facility or to the connection facility of another person, the transmitter shall not require bypass compensation from that customer.

6.7.10 A transmitter shall promptly notify the Board upon becoming aware that a load customer that is a distributor intends to bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person.

6.7.11 Where a transmitter becomes aware that a load customer intends to bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person, the transmitter shall promptly notify all other load customers served by the connection facility that is intended to be bypassed.

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Ontario Energy Board

Ontario

EB-2007-0673

Supplemental Report of the Board

on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors

September 17, 2008

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Appendix B: Amended Filing Guidelines

These filing guidelines supersede the filing guidelines set out in the Appendix to the July 14, 2008 Report.

Changes are highlighted for easy identification.

These filing guidelines set out the Board's expectations for applications by distributors for rate adjustments on the basis of the 3rd Generation IR mechanism.

General

The implementation of the 3rd Generation IR mechanism will occur first with rate adjustments scheduled for May 1, 2009.

The price cap adjustment will be applied to the Service Charge and Distribution Volumetric Rate (including low voltage charges for embedded distributors), net of existing rate adders and rate rebalancing adjustments as determined necessary by the Board. The price cap adjustment will not be applied to Rate Riders, Retail Transmission Service Rates, Wholesale Market Service Rate, Rural Rate Protection Charge, Standard Supply Service – Administrative Charge, Specific Service Charges, Allowances[8], Retail Service Charges or Loss Factors.

The price cap adjustment will reflect inflation less the X-factor, and an adjustment for the transition to the common deemed capital structure of 60% debt and 40% equity.

[8] Transformation and primary metering allowances and any other allowances the Board may determine.

Materiality Threshold

The materiality threshold for applications to recover amounts through rates to fund incremental capital investment needs is discussed in section 2.3 of this Report. The Board has determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$\textit{Threshold Value} = 1 + (\frac{RB}{d}) * (g + PCI * (1 + g)) + 20\%$$

Where:

RB = rate base included in base rates ($);
d = depreciation expense included in base rates ($);
g = distribution revenue change from load growth (%); and
PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

The value for "g" is the % difference in distribution revenues between the most current complete year and the base year. For example, for distributors that were rebased in 2008:

If a distributor applies in	then "g" will be the % difference between
2009	2007 actuals and 2008 Board-approved base
Jan-Mar 2010 Apr-Dec 2010	2007 actuals and 2008 Board-approved base 2008 Board-approved base and 2009 actuals
Jan-Mar 2011 Apr-Dec 2011	2008 Board-approved base and 2009 actuals 2008 Board-approved base and 2010 actuals

- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth); and
- A description of the actions the distributor will take in the event that the Board does not approve the application.

Reporting Requirements

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. Overspending or underspending will be reviewed at the time of rebasing

Z-Factors

Z-factors are events that are not within management's control. A distributor will be expected to supply the details of management's plans for addressing these events in support of the distributor's request for special cost recovery.

A distributor may record amounts which meet the eligibility criteria presented below for Z-factor events.

A distributor is expected to follow the guidelines listed below when applying to the Board to recover from ratepayers the amounts that the distributor has recorded. The Board may limit the recovery of certain amounts.

Filing Guidelines

Distributors are expected to submit evidence that the costs/revenues which were incurred / received meet the three eligibility criteria outlined above.

Distributors are expected to report events to the Board promptly and apply to the Board for any amounts claimed under Z-factor treatment with the next rate application. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts claimed under Z-factor treatment.

The Board expects that any application for a Z-factor will be accompanied by a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations.

Other Matters in Relation to Z-Factors and Incremental Capital Module

Distributors will be expected to file a proposal, including the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocations considered.

Distributors will also be expected to file a detailed proposal including justifications to recover, through a rate rider, the Board-approved incremental revenue requirement. The proposal should specify whether the rate rider will apply on a fixed or variable basis, or a combination thereof, and the time period for collection. A detailed calculation of the rate rider(s) should be provided for each year of the IR plan term.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

Ontario Energy Board

Filing Requirements
For
Electricity Distribution Rate Applications

Last Revised on July 17, 2013
(Originally issued on November 14, 2006)

Board staff provided analysis based on RRR data that suggested that with a threshold equal to 150 percent, there would be more than 20 distributors eligible to apply and with a threshold equal to 200 percent, there would be about 10 distributors eligible. VECC observed that reviewing a capital module application may not be a simple process. It may require the review of productivity improvements inherent in capital spending and the setting of load forecasts. Therefore, VECC recommended that the Board keep this in mind when determining the threshold value. CCC observed that if in the first year the Board receives a large volume of capital module applications, then perhaps the threshold should be reconsidered.

In response to staff's 50 percent estimate for inflating depreciation expense to replacement dollars, Hydro One and the CLD estimated that adding this into the materiality threshold could translate into a decrease in ROE on an annual basis of up to 100 basis points for some distributors. Further, this impact could be cumulative over the three-year IR plan term. Therefore, Hydro One and the CLD did not support including the inflation adder to the materiality threshold, citing concerns that it would be the distributor that would have to fund this 50 percent factor that relates to capital spending. Hydro One and the CLD also observed that distributors need to reliably operate and sustain the businesses that they are licensed to conduct and submitted that if the capital module threshold, the productivity factor and the stretch factors are set too high then they may be compelled to make cost-of-service applications.

Board Policy and Rationale

The Board notes that there are clearly differences in perception as to the purpose of the incremental capital module. Ratepayer groups perceive the capital module as a mechanism aimed solely at addressing extraordinary or special CAPEX needs by distributors. The distributors, on the other hand, perceive the module as a special feature of the 3rd Generation IR architecture which would enable them to adjust rates on an on-going, as-needed basis to accommodate increases in rate base.

In the Board's view, the distributors' view is not aligned with the comprehensive price cap form of IR which has been espoused by the Board in its July 14, 2008 Report. The distributors' concept better fits a "targeted OM&A" or "hybrid" form of IR. This alternative IR form was discussed extensively in earlier consultations but was not adopted by the Board. The intent is not to have an IR regime under which distributors would habitually have their CAPEX reviewed to determine whether their rates are adequate to support the required funding. Rather, the capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.

A review of an application will test whether the applicant has passed the materiality threshold, and, if it does, will scrutinize the need for the requested incremental capital relief. Such scrutiny will entail reviewing the distributor's assumptions and planning and examining alternative options, and its overall CAPEX plan. If the application succeeds, in whole or in part, the Board will adjust rates to reflect a higher CAPEX as appropriate. It is important to note that the adjustment in rates will be linked solely to the costs of the incremental capital. Therefore, distributors should not perceive this activity as an opportunity to true up rate base for any other reason.

The incremental capital for which the Board may provide rate relief is the new capital sought in excess of the materiality threshold. The proceeding to consider an eligible distributor's application for rate relief would examine the reasonableness of the distributor's increased spending plan. If the application is approved, a rate rider would be established to reflect an amount sufficient to accommodate the portion of the approved incremental spending that exceeds the threshold amount. In calculating the rate relief, the Board has determined not to apply the half-year rule so as not to build in a deficiency for subsequent years in the term of the plan.

Distributors that receive rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of rebasing, the Board will carry out a prudence review to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual capital spending during the IR plan term. Overspending or underspending will be reviewed at the time of rebasing.

With respect to the threshold itself, the Board believes that distributors should be able to determine whether or not they are eligible to apply with relative ease. Making that determination should not be an unduly cumbersome exercise. It should be formulaic and it should be relatively easy to populate with the required data.

With rebasing at the end of 2nd Generation IR, and before commencing 3rd Generation IR, a distributor's rates include a CAPEX component. The adequacy of such CAPEX provision in rates during 3rd Generation IR depends on whether or not the need for CAPEX during 3rd Generation IR can be met through existing rates, as adjusted under the 3rd Generation IR regime and considering organic growth. There is no dispute among participants that the price adjustment and organic growth factors should be captured in the calculation of the threshold and that not doing so would amount to "double-dipping".

A constant theme in this and earlier consultations has been the notion that there is diversity among distributors in their needs for future CAPEX. The Board sees merit in an incremental capital module that considers the diversity among the distributors, as long as it can be implemented in a manner that is not unduly cumbersome. The Board has not observed any objections to this approach.

There was considerable support for the formula presented by Mr. Aiken on behalf of LPMA and Energy Probe. That formula incorporates both the impact of the price cap and of load growth on the level of CAPEX that can be funded without additional rate relief and does this on a distributor-specific basis, reflecting both distributor diversity and the differing positions of the distributors in the asset replacement cycle. The data required to perform the calculation is easily obtainable from the distributor's most recent rebasing and IR decisions.

There was a proposal that the price adjustment factor in the formula should be the gross inflation factor, not netted for the X (productivity) factor, to incorporate the expectation for a more efficient use of capital. The Board is not persuaded of the appropriateness of this approach as it goes beyond the need to address the more immediate pressures of incremental investing.

Certain participants suggested that there should be a dead band added to the calculated materiality threshold to prevent marginal applications. The suggested levels ranged from adding 10 percent to 50 percent to the calculated percentage thresholds. The Board finds merit in the suggestion of adding a dead band. However, a high adder may be unreasonably prohibitive for distributors genuinely in need of incremental CAPEX during the term of 3rd Generation IR, as it would connote a regime that is not related to revenue requirement considerations. The Board is satisfied that a 20 percent adder is sufficient at this time.

Accordingly, the Board has determined that the appropriate CAPEX to depreciation threshold value to establish materiality for the incremental capital module should be distributor-specific and derived using the following formula:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1 + g)) + 20\%$$

Where:

- **RB = rate base included in base rates ($);**
- **d = depreciation expense included in base rates ($);**
- **g = distribution revenue change from load growth (%); and**
- **PCI = price cap index (% inflation less productivity factor less stretch factor).**

Further details regarding this formula are set out in Appendix B to this Report.

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0130

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B);

AND IN THE MATTER OF an application by Guelph Hydro Electric Systems Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2011.

BEFORE: Karen Taylor
Presiding Member

Paula Conboy
Member

DECISION AND ORDER
(Issued March 14, 2011 and as corrected March 17, 2011)

Introduction

Guelph Hydro Electric Systems Inc. ("Guelph Hydro"), a licensed distributor of electricity, filed an application with the Ontario Energy Board (the "Board") on September 17, 2010, under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Guelph Hydro charges for electricity distribution, to be effective May 1, 2011.

Guelph Hydro is one of 80 electricity distributors in Ontario regulated by the Board. In 2008, the Board announced the establishment of a new multi-year electricity distribution rate-setting plan, the 3rd Generation Incentive Rate Mechanism ("IRM") process, which would be used to adjust electricity distribution rates starting in 2009 for those distributors whose 2008 rates were rebased through a cost of service review. As part of the plan, Guelph Hydro is one of the electricity distributors that will have its rates adjusted for 2011 on the basis of the IRM process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on July 14, 2008, its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on September 17, 2008, and its *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* on January 28, 2009 (together the "Reports"). Among other things, the Reports contained the relevant guidelines for 2011 rate adjustments for distributors applying for distribution rate adjustments pursuant to the IRM process. On July 9, 2010 the Board issued an update to Chapter 3 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "Filing Requirements"), which outlines the Filing Requirements for IRM applications based on the policies in the Reports.

Notice of Guelph Hydro's rate application was given through newspaper publication in Guelph Hydro's service area advising interested parties where the rate application could be viewed and advising how they could intervene in the proceeding or comment on the application. No letters of comment were received. The Vulnerable Energy Consumers Coalition ("VECC") and the School Energy Coalition ("SEC") applied and were granted intervenor status in this proceeding. Both parties were granted cost eligibility for their participation in the proceeding related to Guelph Hydro's request for an incremental capital module. Board staff also participated in the proceeding. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this proceeding, it has made reference only to such evidence as is necessary to provide context to its findings. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Changes in the Federal and Provincial Income Tax Rates;
- Smart Meter Funding Adder;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Accounts;
- Late Payment Penalty Litigation Costs; and
- Incremental Capital Module.

Price Cap Index Adjustment

Guelph Hydro's rate application was filed on the basis of the Filing Requirements. In fixing new distribution rates and charges for Guelph Hydro, the Board has applied the policies described in the Filing Requirements and the Reports.

As outlined in the Reports, distribution rates under the 3rd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 0.72% and Guelph Hydro's utility specific stretch factor of 0.4%. Based on the final 2010 data published by Statistics Canada, the Board has established the price escalator to be 1.3%. The resulting price cap index adjustment is therefore 0.18%. The rate model reflects this price cap index adjustment. The price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.

The price cap index adjustment will not apply to the following components of delivery rates:

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges;
- MicroFIT Service Charges; and
- Retail Service Charges.

Changes in the Federal and Provincial Income Tax Rates

In its *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* dated September 17, 2008, the Board determined that a 50/50 sharing of the impact of currently known legislated changes, as applied to the tax level reflected in the Board-approved base rates for a distributor, is appropriate for the 3rd Generation IRM applications. This was based on a decision of the Board in a proceeding in relation to natural gas distributors' (EB-2007-0606/615) incentive regulation applications in which tax as a Z-factor was being considered. In this decision, the Board found that a 50/50 sharing is appropriate because it recognizes that tax changes already flow to some extent through the inflation factor, though the precise timing and quantum of the tax reduction during a current IRM period is not known.

The calculated annual tax reduction over the plan term will be allocated to customer rate classes on the basis of the Board-approved base-year distribution revenue. These amounts will be refunded to customers each year of the plan term, over a 12-month period, through a volumetric rate rider derived using annualized consumption by customer class underlying the Board-approved base rates.

In 2011, the maximum income tax rate is 28.25%, the minimum rate for those distributors eligible for both the federal and Ontario small business deduction is 15.50%, and the blended tax rate varies for certain distributors that are only eligible for the Ontario small business deduction. The model provided to distributors calculates the amount of change caused by the tax rate reductions and adjusts distribution rates by 50% of the total change from those taxes included in the most recent cost of service base distribution rates.

The Board finds that a 50/50 sharing of the impact of changes from the tax level reflected in the Board-approved base rates to the currently known legislated tax level for 2011 is appropriate and shall be effected by means of a rate rider over a one-year period.

Smart Meter Funding Adder

On October 22, 2008 the Board issued the *Guideline for Smart Meter Funding and Cost Recovery* which sets out the Board's filing requirements in relation to the funding and recovery of costs associated with smart meter activities conducted by electricity distributors.

Guelph Hydro originally requested to change its utility-specific smart meter funding adder ("SMFA") from $1.00 to $3.32 per metered customer per month.

On March 2, 2011, Guelph Hydro filed a letter stating that on February 28, 2011, Board staff notified Guelph Hydro of some errors in the SMFA Workform. Guelph Hydro submitted that it has corrected the errors and re-filed the SMFA Workform. The revised SMFA Workform calculates a 2011 SMFA of $1.17 per metered customer per month.

The Board notes that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board (G-2008-0002). The Board also observes that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, not fully fund prior capital investment. Such treatment increases the risk, absent a prudence review, of over recovery. The Board is not saying that prudently incurred costs are not recoverable; it is stating that a determination of full recovery will be made as part of an application for a prudence review. Since the deployment of smart meters on a province-wide basis is now nearing completion, and for the reasons noted earlier, the Board expects distributors to file for a final prudence review at the earliest possible opportunity following the availability of audited costs. For those distributors that are scheduled to file a cost-of-service application for 2012 distribution rates, the Board expects that they will apply for the disposition of smart meter costs and subsequent inclusion in rate base. For those distributors that are scheduled to remain on IRM, the Board expects these distributors to file an application with the Board seeking final approval for smart meter related costs. In the interim, the Board will approve Guelph Hydro's SMFA of $1.17 per metered customer per month from May 1, 2011 to April 30, 2012. This new SMFA will be reflected in the Tariff of Rates and Charges, and will cease on April 30, 2012. Guelph Hydro's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall be continued.

The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Guelph Hydro applies for the recovery of these costs on a final basis, if applicable.

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("RTSRs"). Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers (i.e., variance accounts 1584 and 1586).

On July 8, 2010 the Board issued revision 2.0 of the *Guideline G-2008-0001 - Electricity Distribution Retail Transmission Service Rates* (the "RTSR Guideline"). The RTSR Guideline outlines the information that the Board requires electricity distributors to file to adjust their RTSRs for 2011. The RTSR Guideline requires electricity distributors to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new UTR levels and the revenues generated under existing RTSRs. The objective of resetting the rates is to minimize the prospective balances in accounts 1584 and 1586. In order to assist electricity distributors in the calculation of the distributor's specific RTSRs, Board staff provided a filing module. On January 18, 2011, the Board issued its Rate Order for Hydro One Transmission (EB-2010-0002) which adjusted the UTRs effective January 1, 2011. The new UTRs are shown in the following table:

Table 1 - Uniform Transmission Rates	**kW Monthly Rates**		**Change**
	Jan 1, 2010	**Jan 1, 2011**	
Network Service Rate	$2.97	$3.22	+8.4%
Connection Service Rates			
Line Connection Service Rate	$0.73	$0.79	
Transformation Connection Service Rate	$1.71	$1.77	
			+4.9%

The Board has adjusted each distributor's rate application model to incorporate these changes.

Based on the filing module provided by Board staff and the new UTRs effective January 1, 2011 noted in the table above, the Board approves the changes to the RTSRs calculated in the filing module.

Review and Disposition of Group 1 Deferral and Variance Accounts

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Guelph Hydro's Group 1 account balances did not exceed the preset disposition threshold referenced above. The Board therefore finds that no disposition is required at this time.

Late Payment Penalty Litigation Costs

In this application, Guelph Hydro requested the recovery of a one time expense of $207,326 related to the late payment penalty ("LPP") costs and damages resulting from a court settlement that addressed litigation against many of the former municipal electricity utilities in Ontario.

On October 29, 2010 the Board commenced a generic proceeding on its own motion to determine whether Affected Electricity Distributors[1], including Guelph Hydro, should be allowed to recover from their ratepayers the costs and damages incurred as a result of the Minutes of Settlement approved on April 21, 2010 by the Honourable Mr. Justice Cumming of the Ontario Superior Court of Justice (Court File No. 94-CQ-r0878) and as amended by addenda dated July 7, 2010 and July 8, 2010 in the late payment penalty class action and if so, the form and timing of such recovery. This proceeding was assigned file No. EB-2010-0295.

On February 22, 2011, the Board issued its Decision and Order and determined that it is appropriate for the Affected Electricity Distributors to be eligible to recover the costs and damages associated with the LPP class action in rates. The decision set out a listing of each Affected Electricity Distributor and their share of the class action costs that is approved for recovery. The Board also directed Affected Electricity Distributors such as Guelph Hydro to file with the Board detailed calculations including supporting documentation, outlining the derivation of the rate riders based on the methodology

[1] As defined in the Board's Decision and Order EB-2010-0295

outlined in the EB-2010-0295 Decision and Order. The Board noted that the rate riders submitted would be verified in each Affected Electricity Distributor's IRM or cost of service application, as applicable. Guelph Hydro elected to recover the amount approved in the EB-2010-0295 proceeding and accordingly filed the associated rate riders.

The Board has reviewed Guelph Hydro's proposed rate riders and approves them as filed.

Incremental Capital Module

Background

The Request

Guelph Hydro proposed an incremental capital module to recover the incremental capital costs of $10,900,000 associated with the design and construction of a municipal transformer station in South Guelph ("New MTS - Clair"). Guelph Hydro requested that these costs be recovered by means of a rate rider that would be in place until such time that Guelph Hydro files its next rebasing application.

The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* and *The Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors; (together the "Report")* requires that incremental capital expenditures satisfy the eligibility criteria of materiality, need and prudence in order to be considered for recovery prior to rebasing. Applicants must demonstrate that the amounts exceed the Board's materiality threshold and clearly have a significant influence on the operation of the distributor, must be clearly non-discretionary and the amounts must be outside the base upon which rates were derived. In addition, the decision to incur the amounts must represent the most cost-effective option for ratepayers.

Guelph Hydro completed the 2011 IRM3 Incremental Capital Workform, and calculated that the costs of the New MTS - Clair exceed the materiality threshold of $7,000,000. Guelph Hydro's 2011 total forecasted capital expenditures are $20,400,000 (net of capital contributions), which includes the forecasted cost of $10,900,000 to design and construct the municipal transformer station that is the subject of this incremental capital claim.

Guelph Hydro indicated that the incremental capital expenditures related to the design and construction of a municipal transformer station are required to provide relief for the shortage of supply to Guelph Hydro. Guelph Hydro provided a "Guelph South Load Forecast", which indicated that demand in the area of the New MTS - Clair would exceed installed supply in that area of the city between 2010 and 2011. Guelph Hydro stated that the expenses are non-discretionary, and that the expenditures have not previously been included in Guelph Hydro's Board approved rate base.

The New MTS - Clair has a scheduled in-service date of October 2011. Guelph Hydro indicated that its customers are severely at risk of service interruption if there is a loss of high voltage supply at the existing Hanlon TS.

Guelph Hydro requested to recover the costs of the New MTS - Clair by means of a volumetric rate rider that would be in place until such time that Guelph Hydro files its next rebasing application.

Guelph Hydro indicated that if the approval is not granted it would have a significant impact on the operation of the utility. Guelph Hydro noted that, in the short-term, it had sufficient short-term borrowing capacity to carry out its capital plan. However, Guelph Hydro noted that in the long-term, disapproval of Guelph Hydro`s claim may have significant impacts on its future borrowing costs.

The Issues

Project Need

Guelph Hydro provided evidence supporting project need in its application and interrogatory responses. Guelph Hydro indicated that the transformer station is non-discretionary, and that the asset must be in place in 2011 to properly serve its customers.

Board staff submitted that Guelph Hydro has demonstrated immediate short term and long term capacity requirements as evidenced by Guelph Hydro's load forecast and customer requests for capacity. Board staff acknowledged that system reliability is maintained by adding new supply capacity in advance of the development of load.

Board staff noted that from the evidence, it is unclear whether Guelph Hydro will be required to make payments to Hydro One in respect of bypass. Board staff submitted that this may affect Guelph Hydro's analysis of the total costs of alternatives presented. Board staff submitted that the bypass issue, and associated costs, have not been adequately addressed in Guelph Hydro's application.

VECC and SEC both agreed that Guelph Hydro provided adequate evidence to demonstrate that the New MTS - Clair is non-discretionary and supported the incremental capital claim.

In its reply submission, Guelph Hydro noted that it does not expect to make bypass payments to Hydro One since the New MTS is planned for load growth beyond the rated capacity of Hanlon TS.

Prudence

Guelph Hydro provided an in depth evaluation of project alternatives in the form of an optimization exercise at page 15 of Appendix 5.2. Guelph Hydro considered distances from load centers, load capacity, feeder number and length, and other monetary and timing constraints. Three main options were considered in the final analysis; "Hanlon MTS expansion", "New MTS – Clair", and "New MTS – Maltby".

Guelph Hydro concluded that the optimal project option was to construct the new MTS at the Clair location. Guelph Hydro also provided a list of advantages and disadvantages of a self-build versus a Hydro One build, and noted that the Hydro One Hanlon TS option would have an in-service date of late 2012, while the self-build option would be in-service in fall 2011.

Board staff submitted that rate impacts are least under the proposed New MTS - Clair with respect to Guelph Hydro's immediate service area and the transformer is ideally located to serve Guelph Hydro's expected load growth in the immediate area of its distribution system.

Board staff submitted that the other alternatives to construction of the New MTS – Clair are not optimal based on total cost, in-service dates, and the associated risk of supply outages and that the transformer station proposed is the most cost-effective alternative presented. Board staff submitted that it is in the best interest of Guelph Hydro's ratepayers that the New MTS - Clair be built.

VECC submitted that Guelph Hydro has adequately demonstrated the prudence of the proposed expenditure. In its study of supply alternatives, Guelph Hydro considered a number of options including not only different locations for a Guelph-owned MTS but also expansion (by Hydro One) of the existing Hanlon TS. VECC submitted that the preferred supply alternative (the New MTS – Clair) is not only the lowest cost option but also has a number of operational advantages over the other options. VECC further submitted that the selection of Wardrop Engineering to assist with the project was made through an RFP process. SEC supported VECC's position.

Materiality

Guelph Hydro completed the 2011 IRM3 Incremental Capital Workform, and calculated that the costs of the New MTS – Clair exceed the materiality threshold of $7,000,000. Guelph Hydro's 2011 forecasted capital expenditures are $20,400,000 (net of capital contributions), which includes the forecasted cost of $10,900,000 to design and construct the municipal transformer station that is the subject of this incremental capital claim.

Guelph Hydro noted that none of projects included in its 2011 capital budget ($20,400,000) are discretionary in nature.

VECC submitted that the requested incremental capital amount is material, not only in that the spending exceeds the threshold value but that the quantum involved (approximately $10,900,000) is more than half the total 2011 capital budget. SEC supported VECC's position.

Incremental Revenue Requirement Calculation

Guelph Hydro submitted a completed version of the Board's IRM3 Incremental Capital Workform which calculated the 2011 revenue requirement of $1,068,072 associated with the requested incremental capital recovery.

VECC submitted that it has two concerns regarding the calculation of the incremental revenue requirement.

VECC submitted that in determining the Return on Rate Base Guelph Hydro has used the capital structure (4% - Short Term Debt; 49.3% - Long Term Debt and 46.7% - Equity) as approved for its 2008 Rate Application. Since then Guelph Hydro has transitioned, through successive IRM applications, to the Board's deemed capital structure for electricity distributors.

VECC noted that the 2011 rates reflect the Board's deemed capital structure (4% - Short Term Debt; 56% - Long Term Debt and 40% - Equity). Therefore, VECC submitted that the calculation of the incremental revenue requirement arising from the requested capital adjustment should be calculated using the same capital structure. VECC noted that using this deemed capital structure the incremental revenue requirement would be $1,026,883.

VECC noted that its second concern is with respect to the calculation of the MTS associated depreciation expense and rate base. VECC noted that in the Report, it was determined that the half-year rule would not apply "so as to not build in a deficiency for subsequent years in the term of the plan".

VECC noted that in Guelph Hydro's case there are no "subsequent years" since Guelph Hydro rates will be rebased in 2012. As a result, VECC submitted that there is no reason to depart from the Board's standard practice of applying the half-year rule for the determination of depreciation and rate base.

SEC agreed with the submissions of VECC regarding the use of the Board`s deemed capital structure and the application of the half-year rule.

Guelph Hydro submitted that it agrees with the submissions of VECC and SEC regarding the use of the Board`s deemed capital structure. Guelph Hydro submitted that the incremental revenue requirement arising from incremental capital claim should be calculated using the Board`s deemed capital structure.

With respect to the application of the half year rule, Guelph Hydro noted that it followed the policies set out in the Report to complete the Incremental Capital Module calculation. On page 31, the Report states, "In calculating the rate relief, the Board has determined not to apply the half-year rule so as not to build in a deficiency for subsequent years in the term of the plan."

Guelph Hydro submitted that the Incremental Capital Module and the incremental revenue requirement calculation should apply according to the Board's policy, uniformly for all distributors regardless of the IRM year in which the distributor is in the IRM cycle. Guelph Hydro submitted that to follow the suggestion outlined by VECC would be against the Board's policy

Guelph Hydro submitted that its first intent was to file an early re-basing application for 2011 electricity distribution rates. Guelph Hydro noted that it received a Board letter which advised distributors seeking rate rebasing in advance of their next regularly scheduled cost of service proceeding, that they would be required to justify why an early rebasing is necessary. The Board's letter noted that the panel of the Board hearing the application may determine, as a preliminary issue, whether the application for rebasing is justified or whether the application as framed should be dismissed. Further, the Board panel may disallow some or all of the regulatory costs associated with the preparation and hearing of that application, including the Board's costs and intervenor costs. Guelph Hydro submitted that after receiving the above noted letter it decided to stay in its existing IRM cycle. Guelph Hydro submitted that is decision to stay in the IRM plan was driven by a financial analysis and incremental capital module expectations based on a full year approach consistent with the Board's policy.

Revenue Offset

VECC and SEC, in the interrogatory process, sought information regarding the incremental revenues associated with load growth underlying the need for the project. In response, Guelph Hydro provided the area load growth related to the project.

In response to VECC and SEC interrogatories, Guelph Hydro provided the load growth related to the project but took the position that the incremental cost related to connecting new customers would more than offset the initial year's incremental revenue and that only new revenue attributable to the new investment should be considered.

VECC noted that Guelph Hydro has recognized the capital contribution made by the new GS 1,000-4,999 customer. VECC submitted that there is some question as to the level of incremental revenue for 2011. VECC noted that the response to VECC IR #4

(b) suggests it is less than $6,000, the response to VECC IR #4 (a) puts the value at $10,800 and the economic evaluation provided in response to SEC IR #2 reports a 2011 revenue for the GS 1,000-4,000 class of $12,632. VECC requested that Guelph Hydro address these discrepancies in its reply submission.

Guelph Hydro clarified that the correct incremental revenue expected from the GS 1000 to 4999 kW customer is $12,632, which is the amount calculated by the Economic Evaluation Model. Guelph Hydro submitted that the incremental cost of connecting new customers would more than offset the initial year's incremental revenue. Guelph Hydro further submitted that the additional distribution revenue would be included in the economic evaluation model for any new development serviced by the New MTS - Clair, which in turn would be used to reduce the capital contribution from the developer for the costs associated with the new development not the New MTS - Clair.

Incremental Capital Rate Rider – Sunset Date

Guelph Hydro requested an April 30, 2012 sunset date for its Incremental Capital Rate Rider. As part of the Interrogatory process, Board staff asked Guelph Hydro to provide the rationale for the proposed sunset date. Guelph Hydro noted that it is scheduled to file a Cost of Service application for the 2012 rate year, which would set rates commencing May 1, 2012. Therefore, the remaining term of the IR plan is only one year. Guelph Hydro stated that at the time of its Cost of Service application, it will seek the incorporation of the requested incremental capital expenditures related to the New MTS - Clair into its rate base.

Guelph Hydro also noted, in accordance with its May 11, 2010 letter, that it would be seeking a January 1, 2012 effective date for its 2012 rates. If the Board approves the 2012 effective date for the purpose of aligning the fiscal year with the rate year, then the sunset date for the Incremental Capital Rate Rider would be December 31, 2011.

Board staff submitted that the calculation of the rate rider can only be made on the basis of the best available information. At the time of this proceeding, the Board has not provided any direction to Guelph Hydro in regards to the alignment of the fiscal year with the rate year. Therefore, the appropriate sunset date for the Incremental Capital Rate Rider is April 30, 2012.

SEC submitted that if the Board accepts the incremental capital claim, there is a revenue requirement shortfall to be collected by Guelph Hydro relative to 2011. VECC submitted that amount should be divided by twelve months' volume, and collected over the twelve months commencing May 2011.

Deemed Distribution Asset

Guelph Hydro requested that the Board deem the New MTS – Clair to be a distribution asset under section 84(a) of the *OEB Act* in order that it may recover the revenue requirement related to the New MTS – Clair through distribution rates. No parties disagreed with this proposal.

Board Findings

Project Need, Prudence, and Materiality

The Board finds that Guelph Hydro's Incremental Capital request meets all the eligibility criteria set out in The *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*. The New MTS – Clair project is a non-discretionary expenditure that is clearly outside of the base upon which rates were derived. The New MTS – Clair project is required to meet supply requirements in Guelph Hydro's service area. The capital costs are deemed to be prudent as Guelph Hydro has provided adequate evidence that potential alternatives were analyzed and that the New MTS – Clair option represents the most cost-effective option for ratepayers. In addition, Guelph Hydro's non-discretionary 2011 capital expenditures meet the Board's materiality threshold.

Incremental Revenue Requirement Calculation

The Board finds that the incremental revenue requirement arising from the incremental capital claim should be calculated using the Board`s deemed capital structure as this is consistent with how 2011 rates are being set.

The Board finds that the half-year rule should apply to the MTS-related depreciation and rate base calculations. The Board notes that the Report states, "In calculating the rate relief, the Board has determined not to apply the half-year rule so as not to build in a deficiency for subsequent years in the term of the plan." However, in this case, there are no subsequent years in the plan. Guelph Hydro is filing its rebasing application for 2012 rates and therefore no deficiency will be built into the calculation if the half-year rule is applied. The Board notes that the New MTS – Clair will only be in-service for approximately 2-3 months in 2011 and therefore it would be unreasonable to provide for a full-year of depreciation in the 2011 rate year.

With respect to the issue of whether the revenue offset should reduce the revenue requirement of the New MTS - Clair, the Board notes that the formula used to determine the threshold value incorporates a factor for growth. As stated in the Supplemental Report of the Board: "There is no dispute among participants that the price adjustment and organic growth factors should be captured in the calculation of the threshold and that not doing so would amount to "double-dipping"." It is clear that the inclusion of the growth factor "g" in the threshold value formula was intended to address this issue of incremental growth.

The issue here is whether additional growth over and above the growth factor "g" should be factored into the revenue requirement for New MTS – Clair. The Board notes that as a result of future new developments, Guelph Hydro will also incur incremental capital costs to connect new customers to the grid. Under a price cap, the incremental revenue generated from load growth act as an offset to the costs that a distributor incurs to connect new customers. Therefore, the Board finds that the incremental revenue requirement of the New MTS - Clair should not be reduced by the revenue offset.

Incremental Capital Rate Rider – Sunset Date

The Board finds that the incremental revenue requirement related to the incremental capital claim shall be recovered by means of a variable rate rider expiring April 30, 2012.

Determination of the Revenue Requirement

The Board directs Guelph Hydro to file an updated Incremental Capital Project Worksheet and an updated Incremental Capital Workform. The updated Workform should reflect the incremental capital claim of $10,900,000 revised to reflect the use of the Board's deemed capital structure and the application of the half-year rule, Guelph Hydro's Board-approved 2008 Cost of Capital parameters, and the 2011 PILs rates.

Reporting Requirements

Pursuant to the Report, Guelph Hydro will be required to track the difference between the capital expenditure it has proposed in this application and the actual spending. Guelph Hydro will be required to report on the actual amount spent in its 2012 cost of service rate application.

At the time of rebasing, the Board will carry out a prudence review of the actual costs to determine the amounts to be incorporated in rate base. The Board will also make a determination at that time regarding the treatment of differences between forecast and actual spending during the IRM plan term.

Deemed Distribution Asset

Pursuant to section 84(a) of the *OEB Act,* the Board deems the New MTS - Clair to be a distribution asset.

THE BOARD ORDERS THAT:

1. Guelph Hydro's new distribution rates shall be effective May 1, 2011.

2. Guelph Hydro shall file with the Board an updated Incremental Capital Project Worksheet and an updated Incremental Capital Workform reflecting the Board`s findings within seven (7) calendar days of the date of this Decision and Order. The Board will subsequently provide Guelph Hydro with a rate model (spreadsheet) and applicable supporting models and a draft Tariff of Rates and Charges that reflect the elements of this Decision and Order.

All filings to the Board must quote file number **EB-2010-0130,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

DATED at Toronto, March 14, 2011

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2006-0170

Ontario Energy Board

Filing Requirements For Electricity Transmission and Distribution Applications

Last Revised on June 28, 2012
(Originally issued on November 14, 2006)

An Illustration:

Assumptions:	RB	=	\$100 million;
	d	=	\$5 million;
	g	=	1.5% (0.015); and
	PCI	=	0.75% (0.0075).
Calculation:	$1+(\frac{100{,}000{,}000}{5{,}000{,}000})*(0.015+.0075*(1+0.015))+0.20=1.65$		
Result:	The materiality threshold (CAPEX/Depreciation) is 1.65 or 165%. That is, given the assumptions in this example, the Board expects the distributor to manage a CAPEX level of up to \$8.26 million (\$5 million * 1.65) before being eligible to apply to recover incremental amounts.		

2.2.2 Eligible Incremental Capital Amount

In the Supplemental Report, the Board determined that eligible incremental capital amount sought for recovery should be new capital in excess of the materiality threshold. The materiality threshold value, as calculated using the formula discussed in Section 2.2.1, establishes eligibility for incremental capital spending and also marks the base from which to calculate the maximum amount eligible for recovery. A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the 2013 total non-discretionary capital expenditure and the materiality threshold.

2.2.3 Application of the Half-Year Rule

The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In this report the Board determined that the half-year rule should not apply so as not build a deficiency for the subsequent years of the IRM plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the IRM plan term[5]. The Board has adopted this as a clarification to the policy on ICM.

2.2.4 Revenue Requirement Calculation

When calculating the revenue requirement associated with the ICM, a distributor should use the following parameters:

- Cost of Capital
  - In the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued

[5] EB-2010-0130, Guelph Hydro Electric Systems Inc., *Decision and Order*, p. 15

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Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Festival Hydro Inc.	89957 1814 RC0001	2013-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 multiplied by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 plus column 7 minus column 11) 220
1.	1		19,680,816			0		19,680,816	4	0	0	787,233	18,893,583
2.	1b			5,867,563		0	2,933,782	2,933,781	6	0	0	176,027	5,691,536
3.	2		2,992,799			0		2,992,799	6	0	0	179,568	2,813,231
4.	6			99,544		0	49,772	49,772	10	0	0	4,977	94,567
5.	8		1,865,411	701,726		0	350,863	2,216,274	20	0	0	443,255	2,123,882
6.	10		787,820	76,798		0	38,399	826,219	30	0	0	247,866	616,752
7.	12		24,355	92,110		0	46,055	70,410	100	0	0	70,410	46,055
8.	14	CCRA contract - 25 year		436,468		0		436,468	NA	0	0	11,767	424,701
9.	14	CCRA contract- 15 year		480,000		0		480,000	NA	0	0	15,781	464,219
10.	17			126,099		0	63,050	63,049	8	0	0	5,044	121,055
11.	43.2		102,080			0		102,080	50	0	0	51,040	51,040
12.	45		1,428			0		1,428	45	0	0	643	785
13.	46	Server, Router		9,637		0	4,819	4,818	30	0	0	1,445	8,192
14.	47		13,895,868	9,858,999		0	4,929,500	18,825,367	8	0	0	1,506,029	22,248,838
15.	50		39,639	201,119		0	100,560	140,198	55	0	0	77,109	163,649
16.	95	Smart Meters - Not in Use	256,541	280,676		256,541		280,676	0	0	0		280,676
17.	95	Transformer Station Equipmment	8,113,559			8,113,559			0	0	0		
18.	95	Transformers - Not available for	1,426,150	1,193,404		1,426,150		1,193,404	0	0	0		1,193,404
		Totals	49,186,466	19,424,143		9,796,250	8,516,800	50,297,559				3,578,194	55,236,165