MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *The Crown Corporation Public Review and Accountability Act*

AND IN THE MATTER OF Manitoba Hydro's
2012/13 & 2013/14 General Rate Application

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

PAUL CHERNICK, RESOURCE INSIGHT, INC. on behalf of Green Action Centre ("GAC");

PATRICK BOWMAN, INTERGROUP CONSULTANTS LTD. on behalf of Manitoba Industrial Power Users Group ("MIPUG"); and,

PHILIPPE U. DUNSKY, DUNSKY ENERGY CONSULTING on behalf of Consumers' Association of Canada (Manitoba) and Green Action Centre ("CAC/GAC")

December 7, 2012

Manitoba Hydro

MANITOBA HYDRO
2012/13 & 2013/14 GENERAL RATE APPLICATION

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1.0 INTRODUCTION

Manitoba Hydro's Rebuttal Evidence addresses the written evidence filed on behalf of the following parties with respect to Manitoba Hydro's 2012/13 & 2013/14 General Rate Application:

- Mr. Paul Chernick on behalf of the Green Action Centre (GAC);
- Mr. Patrick Bowman on behalf of the Manitoba Industrial Power Users Group (MIPUG); and,
- Mr. Philippe Dunsky on behalf of the Consumers' Association of Canada (CAC) and GAC.

2.0 REVENUE REQUIREMENTS AND RATE PROPOSALS

In this section of Manitoba Hydro's Rebuttal Evidence, Manitoba Hydro addresses the written evidence of Mr. Patrick Bowman on behalf of MIPUG regarding the proposed revenue requirements and rates.

Mr. Bowman's evidence alleges that the proposed rate increases are not the result of declines in export prices but rather are necessitated by Manitoba Hydro's aggressive advancement of the recognition of capital related costs and to a lesser extent, the failure of Manitoba Hydro to control costs. While Mr. Bowman does not provide specific rate recommendations to the Public Utilities Board (PUB), instead preferring to finalize their recommendations after a review of IFF12, he tentatively recommends that rates for 2012/13 and 2013/14 be finalized at the current levels approved on an interim basis as at September 1, 2012 and that the accumulated balance in the deferral account as at March 31, 2012 related to the 1% rate-rollback directed in Order 5/12 be returned to customers. Manitoba Hydro reserves the right to provide additional Rebuttal Evidence based on Mr. Bowman's final recommendations.

Mr. Bowman's evidence was developed based on information contained in IFF11-2 which assumed that Manitoba Hydro would implement International Financial Reporting Standards (IFRS) in the 2013/14 fiscal year, which is the second Test Year in the

Application currently before the PUB. On September 19, 2012, the Accounting Standards Board of Canada (AcSB) extended the optional transition date to IFRS for rate-regulated entities by an additional year to January 1, 2014. Manitoba Hydro has adopted the additional optional deferral and reflected IFRS implementation during its 2014/15 fiscal year in IFF12. As a result, there are no IFRS impacts contained in the 2012/13 and 2013/14 Test Years as presented in IFF12.

To assist the PUB in its review of the 2012/13 and 2013/14 Test Years, Manitoba Hydro has structured the Rebuttal Evidence into two sub-sections, first, those issues raised by Mr. Bowman that pertain to the proposed rate increases for 2012/13 and 2013/14 and secondly, those issues raised by Mr. Bowman that pertain to setting rates in the 2014/15 fiscal year and beyond by virtue of the deferral of IFRS by an additional year.

Through these sections of the Rebuttal Evidence, Manitoba Hydro will demonstrate that the accounting and depreciation practices that form part of the revenue requirement calculations in the Application are appropriate and consistent with accepted rate-making principles for Canadian electrical utilities and that its cost control measures have been successful in constraining costs. Manitoba Hydro will demonstrate that the reasons for the proposed rate increases relate to the need to maintain the financial integrity of the Corporation in order to continue to provide safe and reliable service, and future rate stability for customers.

Manitoba Hydro will also review the proposed accounting and depreciation changes to be made upon the adoption of IFRS in 2014/15 and outline how the associated impacts can be successfully managed within the cost of service rate setting methodology employed to set electric rates in Manitoba, while ensuring rate stability for customers.

2.1 <u>Issues Associated with the 2012/13 & 2013/14 Test Years (Prior to IFRS)</u>

Section 2.1 address those issues raised by Mr. Bowman that pertain to the proposed rate increases for 2012/13 and 2013/14, recognizing that IFRS implementation has now been deferred to Manitoba Hydro's 2014/15 fiscal year in IFF12.

2.1.1 Manitoba Hydro's Overhead Capitalization Practices are Consistent with Canadian Electric Utilities

Mr. Bowman opines that changes to Manitoba Hydro's overhead capitalization practices over the 2008/09 to 2012/13 period do not reflect Manitoba Hydro's changing cost profile in terms of projected increases in capital spending and are shifting the burden of cost recovery of long-lived assets to current ratepayers which is resulting in unnecessary rate increases in the Test Years.

Mr. Bowman is ignoring the information that was provided by Manitoba Hydro during the information request process that explains the reasons for the changes to overhead capitalization practices.

Historically, electric utilities applied a full-cost accounting approach under Canadian Generally Accepted Accounting Principles (CGAAP) whereby common overhead charges such as depreciation on head office buildings were included in the cost of capital items. This interpretation and application of CGAAP was accepted by external auditors as it was consistent across the industry and thus, promoted comparability of the financial results of Canadian utilities. However, the interpretation and application of CGAAP by utilities has changed over the years such that there has been a reduction in the general and indirect overheads that are being capitalized today as compared to the past.

As explained in the response to PUB/MH I-79(a) and PUB/MH II-52(a), the overhead capitalization changes implemented to date by Manitoba Hydro recognize industry trends to move away from full cost accounting and as a result are designed to make Manitoba Hydro's practices more consistent with those of other Canadian electric utilities. In the response to PUB/MH II-52(b) Manitoba Hydro outlined in detail the process and results of its consultations with other Canadian electric utilities as part of the review of its overhead capitalization practices and the fact that the changes that have been implemented to 2012/13 under CGAAP are designed to ensure consistency with other Canadian electric utilities.

These changes are fully compliant with CGAAP and have been fully endorsed by Manitoba Hydro's external auditors.

2.1.2 Manitoba Hydro's Overhead Capitalization Practices are Consistent with PUB Findings & Recommendations

Mr. Bowman's recommendation to return to the overhead capitalization practices employed by Manitoba Hydro prior to 2008/09 are not only inconsistent with electric utility practices, but they are also inconsistent with the past findings and recommendations of the PUB.

On pages 96 and 97 of Order 116/08, the final Order resulting from the 2008/09 General Rate Application (GRA), the PUB expressed concern over the aggressive deferral and capitalization of operating costs under the full cost accounting approach that was previously employed by Manitoba Hydro. The PUB was concerned that aggressive capitalization of operating costs would inappropriately burden future ratepayers and recommended in paragraph 2 at page 340 that the Company consider the early adoption of less aggressive IFRS overhead capitalization practices. In this context, the PUB is using the term less aggressive to mean capitalizing less overhead costs.

The PUB further reiterated its concerns about the potential for aggressive deferral and capitalization of operating costs which could burden future ratepayers on page 85 of Order 99/11 which was an interim Order relating to the 2010/11 & 2011/12 GRA. Through the last Electric GRA, the PUB and Intervenors were fully aware of the overhead capitalization changes that had been implemented or were planned to be implemented up to 2011/12 and the PUB did not take exception to these changes for rate-setting purposes in Order 5/12, the final Order resulting from the 2010/11 and 2011/12 GRA.

Manitoba Hydro notes that MIPUG did not make any argument with respect to these overhead capitalization changes as part of the hearing process leading up to Order 5/12. Manitoba Hydro does not support a recommendation to return to the overhead practices employed by Manitoba Hydro five years ago, when the more recent changes have clearly been accepted for rate-making purposes by the PUB.

At page 1-3, lines 26-27 Mr. Bowman also suggests in his evidence that Manitoba Hydro has not been sensitive to customer impacts in making these changes. Manitoba Hydro disagrees. Manitoba Hydro has been making changes gradually over the past number of years in an effort to transition them into customer rates and moderate the impact on customers.

2.1.3 Manitoba Hydro’s Overhead Capitalization Practices are Consistent with Future Capital Spending Plans

Mr. Bowman’s view that the changes to overhead capitalization practices are inconsistent with Manitoba Hydro’s changing cost profile and projected increases in capital spending in the future is equally flawed. At page 4-10, lines 10-12, Mr. Bowman appears to be taking the position that the changes to the overhead capitalization practices are somehow resulting in direct capital costs being expensed as operating costs. This is not the case. In pages 3 to 5 of Appendix 5.6 of the Application and in the response to PUB/MH I-44(a) and PUB/MH I-79(a), Manitoba Hydro outlined the nature of the costs that are now being expensed under current industry practices as compared to the previous full cost accounting practices, as follows:

- Interest & Facilities Overhead on Stores
- Executive Costs
- Property Taxes on Facilities
- Interest on Common Assets
- General & Administrative Departmental Costs (e.g. Corporate Accounting, Library, Cash Management & Credit, Corporate Risk Management)
- Interest on Motor Vehicles
- Information Technology Infrastructure & Related Support Costs
- Building Depreciation & Operating Costs

An examination of the nature of these costs would indicate that they are not direct capital expenditures, rather, they are sunk costs (i.e. building depreciation and IT infrastructure costs) or costs which do not vary directly based on the level of capital activity (i.e. Executive costs). Stated differently, it is appropriate that these overhead costs no longer be capitalized because they are relatively fixed and cannot be directly linked with a specific capital project. Without a direct relationship to a capital asset, these costs are more closely linked to current operations and as such it is appropriate from a rate-setting perspective that they be borne by the current ratepayers that derive the majority of the benefit from the expenditures.

At page 4-10, lines 23-25, Mr. Bowman argues that Manitoba Hydro is not capitalizing costs associated with recent year's Equivalent Full Time position (EFT) additions despite the fact that this growth in EFTs was justified on the basis of Manitoba Hydro's growing capital program. Manitoba Hydro disagrees with this assertion. To the extent that such EFTs are working on a capital project, they will be required to directly charge to that project and as a result, the wages, benefits, and direct support costs associated with such EFTs will continue to be capitalized.

In PUB/MIPUG I-15, Mr. Bowman has asserted that the capitalized EFTs are 679 lower in 2013/14 than what Manitoba Hydro has calculated in PUB/MH II-49(a) and therefore comes to the incorrect conclusion that Manitoba Hydro has not capitalized employee additions since 2004/05. Manitoba Hydro disagrees with the underlying formula and assumptions used by Mr. Bowman in coming to this conclusion. Mr. Bowman asserts that the impact of accounting changes must be deducted in order to properly reflect the correct capitalized EFT figure. This is incorrect as a significant portion of the accounting changes (i.e. depreciation, interest and property taxes on facilities and IT infrastructure) have no direct relationship with EFTs and should not be deducted in the calculation of capitalized EFTs. The capitalized EFT figure of 2825 for 2013/14 (per PUB/MH II-49(a)) demonstrates the growth in EFTs necessary to support Manitoba Hydro's capital program.

2.1.4 The Revised Service Lives Implemented by Manitoba Hydro Effective April 1, 2011 are Reasonable

Mr. Bowman's evidence expresses concern related to the service lives selected for some hydraulic generation and distribution components, specifically accounts 000A Dams, Dykes & Weirs, 000D Spillways, 4000J Distribution Poles & Fixtures and 4000L Distribution Overhead Conductor & Devices (please note, Mr. Bowman's evidence incorrectly describes account 4000J as Metal Towers).

Dams, Dykes & Weirs (Account 000A): Mr. Bowman's evidence expresses concern that the service life adopted for this account is not sufficiently long given Manitoba Hydro's own retirement data. While it is generally expected that existing hydraulic generation plants will eventually be replaced at or near their current general location, the nature of the redevelopment for each site is as yet unknown. As such, it is not possible to determine the degree of modification that might be required to existing dams, dykes and weirs in association with the eventual future site redevelopment. From a rate-making perspective, the costs associated with the original construction of the dams, dykes and weirs should be recovered from the customers that benefit from the expenditure of those costs. Until such time as redevelopment plans mature to the point where it can be determined whether and how much of the current waterway infrastructure will be retained, only the customers in place during the lifespan of the existing powerhouse can be assured of receiving benefit from the associated dams, dykes and weirs. In the future, the service life estimates will be reviewed and adjusted in accordance with redevelopment plans as they become available. Customers receiving service from the redeveloped site should more appropriately bear the cost of the redevelopment efforts.

Spillways (Account 000D): Mr. Bowman's evidence expresses concern that the service life adopted for this account is not sufficiently long given Manitoba Hydro's own retirement data. The IOWA curve for spillway assets indicates a greater level of early retirement than has been historically experienced by Manitoba Hydro. Due to age of existing plants, there is limited data to draw on with respect to historical retirements. The choice of a 75 year service life reflects the expectation for at least one major spillway replacement or refurbishment during the lifespan of a hydraulic generating station. The 75 year service life is consistent with an average timing of actual and planned spillway remediation work of 76 years for the four oldest generating stations. Spillway remediation work was carried out at Seven Sisters in 1984 at age 53, and at Great Falls in 1986 at age 63 (PUB/MH II-34a & PUB/MH II-34c). CEF12 reflects planned and in-progress spillway remediation work for Slave Falls at approximately 85 years and for Pointe du Bois at approximately 105 years.

Distribution Poles and Overhead Conductor (Accounts 4000J & 4000L): Mr. Bowman's evidence opines that the lives adopted for these two accounts are excessively long given Hydro's own retirement data. As indicated in the response to PUB/MH I-82(e), the retirement data to which Mr. Bowman refers has been statistically developed using the computed mortality method. During the course of the depreciation study, it was determined that the statistically derived aging for these accounts did not align well with the actual age distribution of installed plant. The age distribution of the installed plant was under review through concurrent work to collect pole inventory data. The revised service life estimates for the depreciation study were developed with greater weight placed on actual pole inventory data and the representations of operational and engineering staff than on the statistical results produced during the depreciation study.

The longer life adopted for depreciation rate purposes is consistent with the findings of Manitoba Hydro's Report on Distribution Asset Condition (Appendix 40). Based on the previous estimate for depreciation purposes of a 31 year service life for distribution poles with an R2 IOWA curve retirement profile, less than 5% of poles would be expected to survive to the age of 52 years. The 31-R2 service life assumption is not consistent with actual inventory findings which indicate that approximately 25% of the existing pole population was installed in conjunction with Rural Electrification, between 1945 and 1960.

These poles are currently between 52 and 67 years of age.[1] The revised assumption for depreciation purposes of a 55 year life with an R3 IOWA curve would anticipate retirement activity peaking at around 57 years of age. This is consistent with projections made by distribution staff for significant increases in pole replacement activity in the upcoming years as older poles reach the end of their life.

The longer life estimate for distribution poles and conductor is also consistent with industry trends towards longer asset lives.

2.1.5 Recovery of Net Salvage Costs in Depreciation Rates is a Legitimate Regulatory Concept under a Rate-Regulated Accounting Model

In response to MH/MIPUG I-8, Mr. Bowman recommends that Manitoba Hydro remove net salvage costs from electric depreciation rates, commencing in the Tests Years. Manitoba Hydro's proposal is to remove net salvage costs from electric depreciation rates upon the adoption of IFRS in 2014/15.

Manitoba Hydro does not recommend an early adoption of the removal of net salvage from depreciation rates as it is a valid construct for determining depreciation expense under the current rate-regulated accounting model. The purpose of including net salvage costs into depreciation rates it to ensure that the ratepayers benefitting from the respective assets are bearing the cost of removing those assets at the end of their useful life.

Manitoba Hydro's proposal to eliminate this practice with the implementation of IFRS is driven by the fact that including net salvage costs in depreciation rates is not permitted under IFRS. Under IFRS, the future costs to retire and salvage assets will become a cost of the replacement asset. This approach, as recommended in Mr. Bowman's evidence, is consistent with requirements of IFRS and will be adopted by Manitoba Hydro upon its transition to IFRS.

[1] Appendix 40 – Manitoba Hydro Report on Distribution Asset Condition – November 9, 2012, page 107.

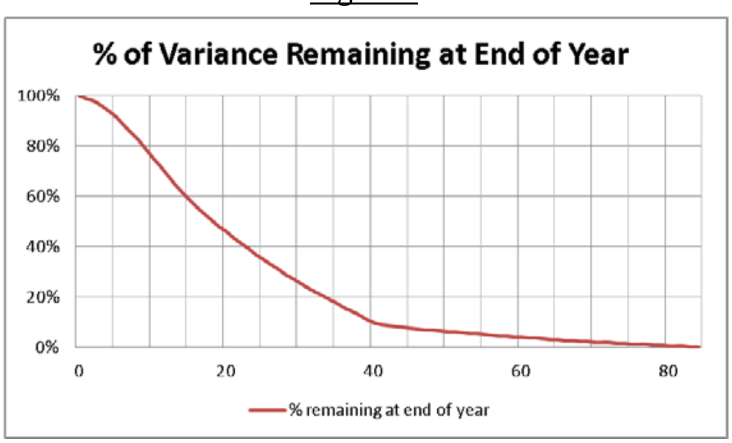
2.1.6 Manitoba Hydro's Proposed Treatment of the Accumulated Depreciation Surplus is Fair to Ratepayers

In response to PUB/MIPUGI-17, Mr. Bowman indicates that the accumulated depreciation surplus that results from the application of the proposed changes in the recent depreciation study should likely be refunded over the remaining life of the assets as proposed by Manitoba Hydro. However, Mr. Bowman's acceptance of this approach appears to be conditional on Manitoba Hydro also adopting the other approaches for the recognition of capital-related costs recommended in Mr. Bowman's evidence (e.g. the ASL approach, with no net salvage and full cost accounting overhead allocations).

Manitoba Hydro acknowledges Mr. Bowman's acceptance of Manitoba Hydro's approach to the handling of the accumulated depreciation surplus. The surplus accumulated over a long period of time, using depreciation rates that were based on the best information available and practices in use at the time. Refunding the surplus over the remaining life of the accounts to which they pertain is consistent with past regulatory practice, recognizes the long-term nature of the assets to which it relates, and is consistent with the objective of rate stability for customers.

At page 4-13, line 20, Mr. Bowman asserts that Manitoba Hydro proposes to amortize only $7 million per year of the surplus balance, which implies an 80 year amortization period. In fact, the $7 million represents only the first year of amortization of the balance as this amount will fluctuate from year to year as it is based on the different service lives of the multiple asset groups for which it pertains. Figure 1 shows that the majority of the amortization is expected to occur over 40 years.

Figure 1



Manitoba Hydro does not agree with Mr. Bowman's condition that the amortization of the surplus over the life of the respective plant assets should only be implemented if Manitoba Hydro also agrees to all of the other recommendations in Mr. Bowman's evidence. Overall, the treatment of the surplus represents the appropriate regulatory treatment for the nature of that particular balance.

2.1.7 Manitoba Hydro has Implemented Effective Cost Control Measures in Minimizing Growth in OM&A Expenditures

Mr. Bowman contends that Manitoba Hydro's current cost control initiatives appear to have had at most a small effect on the rate of growth in OM&A costs.

Manitoba Hydro has updated the analysis of the average annual increase in OM&A costs to reflect cost projections per IFF12. Manitoba Hydro has limited increases in OM&A costs to an average annual increase of 1.68% net of accounting changes and the incremental costs associated with the in-service of the Wuskwatim Generating Station over the period 2009/10 through 2013/14. This is below the average annual increase in Canadian CPI of 2.10% over the same period. Please see Figure 2 below.

Figure 2

(in thousands of $)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual Increase
Electric OM&A (per Annual Report)	$ 379,697	$ 403,067	$ 410,717	$ 461,800	$ 477,600	
Less: Subsidiaries	2,146	6,121	7,414	6,491	6,946	
Accounting Changes	11,240	30,910	34,973	75,411	78,318	
Wuskwatim				5,589	10,797	
Electric OM&A after adjusting for subsidiaries, accounting changes and Wuskwatim	$ 366,311	$ 366,036	$ 368,330	$ 374,309	$ 381,539	
% Increase	4.28%	-0.08%	0.63%	1.62%	1.93%	1.68%
Number of Customers	532,359	537,299	542,681	548,944	555,955	1.06%
Cost Per Customer	$ 688	$ 681	$ 679	$ 682	$ 686	
% Increase (Decrease)	3.32%	-0.99%	-0.37%	0.46%	0.65%	0.61%
Canadian CPI	1.40%	3.30%	1.90%	1.80%	2.10%	2.10%

Manitoba Hydro has achieved minimal cost increases despite significant cost pressures in wages, salaries & overtime costs, benefits and other input commodities such as fuel.

The increase in wages and salaries is primarily due to negotiated contract settlements reflecting competitive pressures in the market place in order to attract and retain skilled employees in the increasingly competitive energy sector.

The increase in benefit costs reflects higher pension costs due to the amortization of investment fund losses, higher vacation expense due to an increase in the number of days accrued and higher extended health benefit costs due to negotiated coverage enhancements (e.g. vision coverage, massage therapy, chiropractor). According to information provided by Blue Cross, healthcare costs are increasing annually in the range of 8- 10% including prescription drugs. For example, costs for eye exams have risen 10.6% from 2007 to 2011. In addition, beginning in 2011/12 the reduction in the discount rate on pension and other benefit obligations is also contributing to higher benefit costs.

Manitoba Hydro's commodity costs, such as fuel, have also increased by 4% since 2009/10 primarily due to higher prices. The following table, taken from Statistics Canada, provides an overview of relevant input cost indices for Manitoba Hydro:

Commodity	**Cost changes (January 2009 to December 2011)**
Mineral Fuels	97%
Non-Ferrous Metals	47%
Wire and Cables > 1000v	22%
Ferrous Metals	6%

To offset these cost drivers, Manitoba Hydro has specifically implemented a number of cost constraint initiatives including restrictions on external hiring, out of province travel, overtime and reductions in community sponsorships and donations. Cost savings have also been achieved as a result of the centralization of staff at both 360 Portage and 820 Taylor resulting in lower facility lease costs, maintenance and property services as well as energy efficiencies in the new building. Manitoba Hydro has also engaged in continuous process improvement activities to gain operational efficiencies and improve productivity in managing its resources and controlling expenditures. Process improvements include automation, utilization and coordination of resources, and reviews of work procedures including standardized of work practices.

2.1.8 Manitoba Hydro's Proposed Rate Increases are Reasonable and Serve to Protect Customers

The following table (Figure 3) summarizes Manitoba Hydro's actual electric operations net income for the past five years and the projected net income for the 2012/13 and 2013/14

Test Years from IFF12, as well as the impacts of the interim rate increases that have been implemented in 2012/13 and the proposed rate increase in 2013/14:

Figure 3

Net Income - Electricity Operations

	Actual					Forecast	
(in millions of $)	2008	2009	2010	2011	2012	2013	2014
Revenue							
General Consumers Revenue							
- at approved rates	$ 1,075	$ 1,127	$ 1,145	$ 1,200	$ 1,214	$ 1,250	$ 1,289
- 1% rate deferral					(23)		
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	366	323	202	172	98	97	62
Other Revenue	8	16	6	6	6	14	15
	1,448	1,466	1,353	1,379	1,295	1,362	1,366
Expenses	1,112	1,209	1,193	1,240	1,234	1,404	1,450
Non-controlling Interest			-	-	-	14	24
Net Income (loss) before interim and proposed rate increases	$ 337	$ 257	$ 160	$ 139	$ 62	$ (28)	$ (59)
Interim Rate Increases (2.0% April 1, 2012 & 2.5% September 1, 2012)	-	-	-	-		45	58
Proposed rate increases (3.5% April 1, 2013)	-	-	-	-		-	48
Rate rollback reinstatement	-	-	-	-		36	14
Net Income after proposed rate increases & rate rollback reinstatement	$ 337	$ 257	$ 160	$ 139	$ 62	$ 53	$ 60

Retained Earnings and Financial Ratios (before interim & proposed rate increases)

	2008	2009	2010	2011	2012	2013	2014
Retained Earnings (electric operations)	$ 1,772	$ 2,029	$ 2,189	$ 2,328	$ 2,390	$ 2,362	$ 2,303
Debt to Equity Ratio (electric operations)	0.73	0.77	0.72	0.72	0.74	76:24	79:21
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	0.95	0.90
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	0.90	0.67

Retained Earnings and Financial Ratios (after proposed rate increases & rate rollback reinstatement)

	2008	2009	2010	2011	2012	2013	2014
Retained Earnings (electric operations)	$ 1,784	$ 2,028	$ 2,190	$ 2,328	$ 2,390	2,442	2,502
Debt to Equity Ratio (electric operations)	0.73	0.77	0.72	0.72	0.74	75:25	78:22
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	1.09	1.10
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	1.09	0.89

Tab 2 of the Application and PUB/MH I-61 (a) set out a number of important justifications for the proposed increases. IFF12, in particular, and Figure 3 above further substantiate these justifications, notably:

1) **To avoid incurring losses on operations.** As noted in Figure 3, without the rate increases that have been approved on an interim basis for 2012/13, the reinstatement of the 1% rate roll-back and the further proposed rate increase of 3.5% on April 1, 2013, Manitoba Hydro is projected to incur losses on electric operations of $28 million in 2012/13 and $59 million in 2013/14.

   Based on the update of water flow conditions and the various other assumptions that form part of IFF12 and assuming that the interim and proposed rate increases are approved and the 1% rate roll-back is reinstated in 2012/13, Manitoba Hydro is projecting a moderately higher net income (compared to IFF11-2) in 2012/13 of $53 million and a slightly lower net income in 2013/14 of $60 million, which are consistent with the actual net income from 2011/12. However, these projected income levels are significantly down from the average levels of the previous five years.

Allowing the utility to incur a net loss on operations is not in the best interest of electricity ratepayers and could result in the requirement for substantially higher rate increases in the future.

2) **To limit the extent to which financial ratios are projected to deteriorate and to maintain the financial and credit rating integrity of Manitoba Hydro.** In IFF12, the electric operations debt to equity ratio is projected to meet the 25% target in 2012/13 and to deteriorate to 22% in 2013/14 and the interest coverage ratio is projected to be 1.09 and 1.10 in 2012/13 and 2013/14, respectively. Without the proposed rate increases, the debt to equity ratio is projected to deteriorate to 24% in 2012/13 and to 21% in 2013/14 and interest coverage ratio is projected to be 0.95 and 0.90 in 2012/13 and 2013/14, respectively.

In particular, Manitoba Hydro is concerned about the deterioration of its interest coverage ratio below 1.00 given the importance of this financial metric to bondholders and credit rating agencies and the potential negative consequence for the credit rating of the Province of Manitoba and Manitoba Hydro. See Manitoba Hydro's response to CAC/MH I-6 for additional information regarding the importance of Manitoba Hydro's financial ratios.

3) **To compensate for the reduced prices for non-firm electricity sales on the export market.** The above summary table demonstrates that there has been a significant reduction in net extraprovincial revenues over the last number of years which is primarily due to low export prices, and is projected to continue into the 2012/13 and 2013/14 Test Years.

In IFF11-2 there was a reduction in forecast net extraprovincial revenues of $4.0 billion as compared to IFF10-2 over the 20 year period to 2031/32. In IFF12 there is a further reduction in forecast net extraprovincial revenues of $2.9 billion as compared to IFF11-2 over the 20 year period to 2031/32.

The reductions in net extraprovincial revenues will have a significant negative impact on the net income of Manitoba Hydro in the Test Years. At page 4-1 of his written evidence, Mr. Bowman concludes that the reductions in net extraprovincial revenues will be "largely addressed by other offsetting factors within Hydro's cost structure". For example, Manitoba Hydro does not understand the basis under which a reduction in net income (largely driven by a reduction in net extraprovincial revenues) could be viewed as a cost structure offset to extraprovincial revenues. While there may be some partial offsets (for example with fuel costs), the reality is that the magnitude of the reduction in extraprovincial revenues will adversely impact net income and it is important from a rate stability perspective to recognize this reduction in customer rates on a gradual basis.

4) **To provide customers with rate stability and predictability and to avoid the need for much higher rates in the future.** The proposed rate increases are in keeping with Manitoba Hydro's approach to implement regular and modest rate increases to ensure the maintenance of an adequate financial structure. A sufficient level of equity allows the Corporation to withstand the risks and uncertainties inherent in its operations and to address adverse financial consequences outside of its control and in so doing, promote rate stability and avoid the need for large or sudden rate increases in the future. Even with the proposed rate increases in the Test Years and the indicative rate increases in IFF12, the electric operations retained earnings are projected to be relatively flat to 2021/22.

Mr. Bowman's recommendation to increase rates at the rate of inflation only does not compensate for the forecast reduction in net extraprovincial revenues and would be insufficient to maintain a reasonable level of net income and financial ratios. It also places future rate stability at risk and increases the risk of potential negative consequences to the credit rating of the Province of Manitoba and Manitoba Hydro.

2.2 Issues Associated with 2014/15 and Beyond (after IFRS Implementation)

As a result of the additional one-year deferral of IFRS for rate-regulated entities, Manitoba Hydro will now adopt IFRS in its 2014/15 fiscal year. Accordingly, Manitoba Hydro will also defer the adoption of a number of accounting policy changes that were designed to be IFRS compliant such as the write-off of rate-regulated assets, further reductions to overhead capitalized, removal of asset retirement costs from depreciation rates and the change to the Equal Life Group depreciation method for financial reporting purposes.

These changes no longer impact the setting of rates for the 2012/13 and 2013/14 Test Years, but rather will influence rate-setting in the 2014/15 period and beyond. Mr. Bowman's evidence was developed before these changes were incorporated into IFF12 and filed with the PUB and Intervenors and as such, Manitoba Hydro will address them separately in Section 2.2.

2.2.1 Rate-Regulated Accounting is currently Under Review by the IASB

In its evidence, Mr. Bowman is critical of Manitoba Hydro for "electing" to write-off all of its deferred Power Smart DSM costs and to commence expensing of these costs as they are incurred as part of the implementation of IFRS. Mr. Bowman noted that the reason for the delays in implementing IFRS for utilities is due to the active and unresolved debate surrounding the recognition of rate-regulated accounting under IFRS.

Mr. Bowman's characterization of Manitoba Hydro "electing" to write-off DSM costs upon transition to IFRS is incorrect. Manitoba Hydro's assumption that DSM costs will be written off on transition to IFRS is not an optional election, but rather was based on years of discussion and analysis in the utility industry indicating that continued recognition of rate-regulated assets would not be permitted under IFRS. While the International Accounting Standards Board (IASB) has recently reinitiated its rate-regulated activities project and there is potential that an IFRS standard may be developed that would allow for the recognition of rate-regulated accounting, the project has yet to reach a stage where any forecast assumption other than de-recognition would be considered reasonable.

Manitoba Hydro will continue to monitor the status of the IASB rate-regulated activities project and will adjust its accounting policies and financial forecasts accordingly. For the purposes of the 2013/14 Test Year review, the assumed write-off of DSM has been deferred to 2014/15 in IFF12.

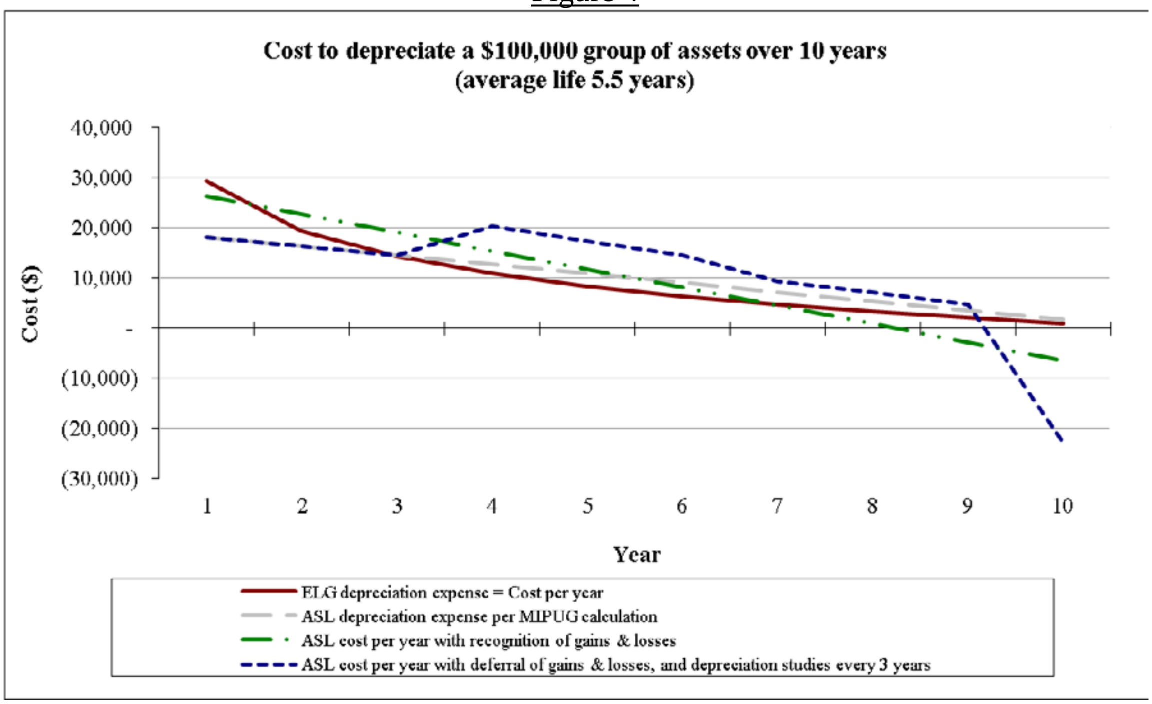
2.2.2 Manitoba Hydro's Proposed Change to ELG Improves Intergenerational Equity

Mr. Bowman's evidence opines that Manitoba Hydro's proposed adoption of the Equal Life Group (ELG) method of depreciation under IFRS is onerous to current ratepayers and recommends that the Average Service Life (ASL) method should be retained for rate-setting purposes to be consistent with other Crown owned and hydro dominated utilities.

Mr. Bowman asserts that the ELG approach results in far higher costs to ratepayers in the early years than ASL and provides an example in the response to MH/MIPUG I-4 which on the face of it, appears to support that conclusion. However, the ASL calculations provided by Mr. Bowman fail to consider the accounting for the gains and losses resulting from the retirement of assets. For the declining asset balance scenario provided by Mr. Bowman, use of ASL results in an earlier recognition of expense than ELG when the impact of gains and losses on asset retirements are considered.

The total net cost to ratepayers including the impacts of gains and losses is shown in the following chart (Figure 4). Supporting calculations may be found in Attachment A:

Figure 4



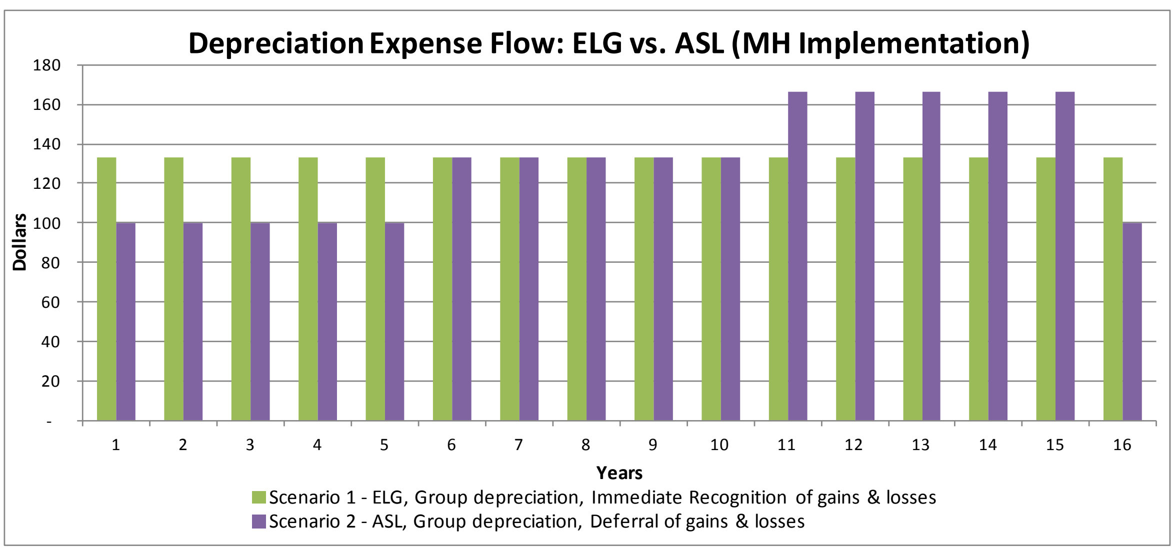
Under an ASL scenario where the gains and losses resulting from retirement are recognized as incurred, the entire $100,000 original cost is charged to ratepayers in the first 5.5 years, while ratepayers in the later years benefit from the realization of gains on the retirement of assets. The net cost charged to rate payers in years 6-8 is returned in years 9-10 when the magnitude of the gains exceeds the annual depreciation expense charged.

Under an ASL scenario where gains and losses are deferred and depreciation studies are carried out periodically (assumed every 3 years in the above scenario), the account will be found to have a significant accumulated depreciation deficit at the first depreciation study, resulting in a significant upward adjustment to depreciation rates, followed by further depreciation rate adjustments in subsequent studies, and realization of a gain or loss at the end of life of the asset pool. This methodology results in an overall expense pattern which bears little resemblance to the assets available for use in each year. As with the prior ASL scenario, the entire $100,000 original cost has been charged to ratepayers in the first 5.5 years, and ratepayers in year 10 benefit from a repayment of excess depreciation charges resulting from the recognition of a gain on retirement of the final assets in the group.

In contrast, the ELG method produces a declining depreciation expense pattern which reflects the varying life spans of the individual assets which make up the pool. As such, there is no need to refund over-depreciated amounts to ratepayers in the later life of the asset pool with ELG.

When ELG is used for a stable asset pool, where individual parts are replaced when they reach end of life, as is common for utility assets, ELG delivers an equal amount of expense each year throughout the life of the pool. Assuming the asset in question generates the same level of output over its service life, charging customers with an equal depreciation expense each year satisfies the concept of intergenerational equity. In contrast, applying ASL to the same group with the deferral of gains and losses results in an increasing expense pattern. The following chart provides a comparison of the depreciation expense generated under each scenario. Supporting calculations for the scenarios illustrated in this chart (Figure 5) may be found in Attachment B:

Figure 5



Mr. Bowman argues that this increasing expense pattern is appropriate for a hydro dominated utility as the profitability of hydraulic generation assets increases over time. Manitoba Hydro contends that the profitability of a hydraulic generating station is dependent on a number of variables such as future electricity prices, exchange rates and water levels. All such variables occur and are influenced by factors completely independent of the physical operations of the generating station and should thus, not be the determining factor in the selection of the station's depreciation rates. Manitoba Hydro is not aware of any utility that uses a depreciation method intended to match depreciation expense to profitability. Any attempt to match depreciation expense flows to profitability would require ongoing adjustments to depreciation rates as other forecast variables changed, which would introduce a significant level of volatility, and as such, could not be considered to be either a rational or a systematic method of depreciation.

While Mr. Bowman contends that the ELG approach is inconsistent with the spirit and intent of IAS 16, Manitoba Hydro would like to point out that the IASB issued an exposure draft on December 4, 2012 which clarifies that: "A method that uses revenue generated from an activity that includes the use of an asset is not an appropriate depreciation method for that asset, because it reflects a pattern of the future economic benefits being generated from the asset, rather than a pattern of consumption of the future economic benefits embodied in the asset" (Proposed Amendments to IAS 16, paragraph 62A).

The primary function of Manitoba Hydro's assets is to ensure an adequate and continuing supply of electricity for domestic customers. Any profit resulting from the export of excess power is reflected as a direct benefit to domestic customers as it is earned.

While Mr. Bowman's evidence primarily concentrates on generating assets, Manitoba Hydro notes that hydraulic generation assets comprise only 38% of the total asset base as at March 31, 2012.

Manitoba Hydro's proposed change to the ELG procedure is the preferred alternative for both financial reporting and rate-setting purposes as it improves inter-generational equity by matching the amortization of cost, to the life of the assets in use, ensuring that each generation of ratepayers is charged only for assets of benefit to that generation.

2.2.3 Manitoba Hydro's Proposed Change to ELG is Appropriate for an Electric Utility

Mr. Bowman's evidence states that ELG is not well suited to Manitoba Hydro's operations and that no other Canadian Crown utility nor hydro-dominated utility is cited as making use of the ELG approach. This includes the following Canadian utilities as set out in Attachment C, Table C-1 of Mr. Bowman's evidence: BC Hydro and BC Transmission and Corporation; Newfoundland and Labrador Hydro; Northwest Territories Power Corporation; Qulliq Energy Corporation; SaskPower and Yukon Energy Corporation.

It should be noted that the nature and level of component breakdown varies between utilities, and that the larger Crown Utilities cited in Mr. Bowman's evidence have implemented ASL differently than Manitoba Hydro, in that they have divided their depreciable assets into a much more granular set of components and use a 'unit' accounting rather than a 'group' accounting depreciation approach. For Newfoundland and Labrador Hydro, this is confirmed in the latest negotiated settlement agreement referenced by Mr. Bowman. The increased level of componentization is evident from a review of the BC Hydro[2] and the Newfoundland and Labrador Hydro[3] documents referred to in Mr. Bowman's evidence. It is Manitoba Hydro's understanding that SaskPower and Hydro Quebec also use ASL with a unit accounting depreciation methodology.

Due to the differences in implementation approach, the depreciation expense recorded by Manitoba Hydro using a group accounting approach under ASL (Scenario 2) is not directly comparable with that of entities using a unit accounting approach under ASL (Scenario 3). Manitoba Hydro's proposed use of ELG (Scenario 1) produces results that are more consistent with that of utilities which use ASL in a unit accounting approach. The following chart provides a comparison of the relevant scenarios. Supporting calculations for the scenarios illustrated in this chart (Figure 6) may be found in Attachment B:

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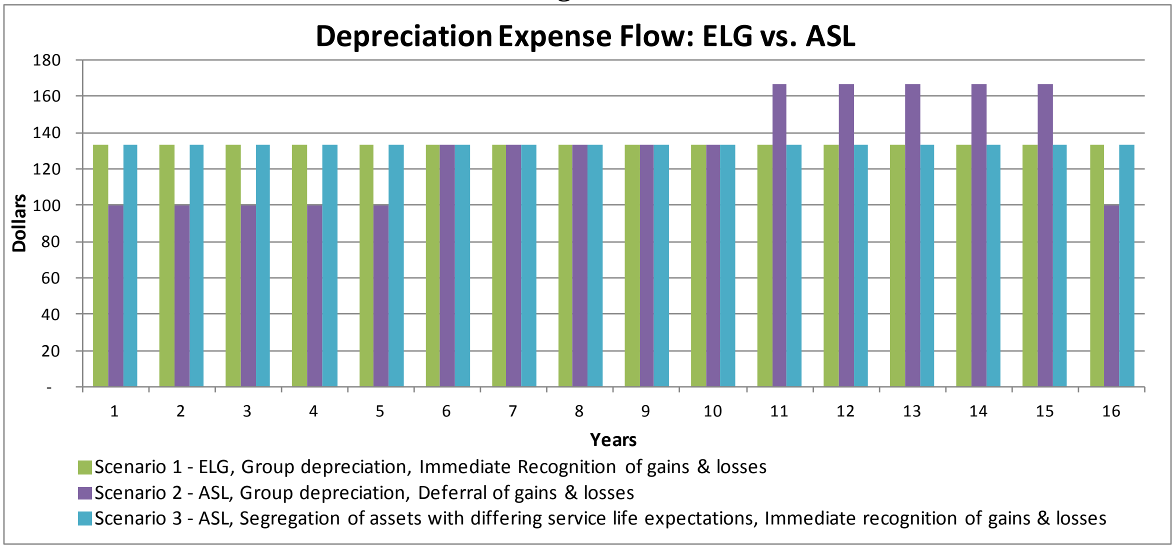
[2] BC Hydro and Power Authority F2012 - 2014 Revenue Requirements Application; Appendix G: Review of BC Hydro's Implementation of International Financial Reporting Standards by Gannett Fleming. Pages 14-20 (January 24, 2011).
http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/rev_req/amended_bch_f12_f14_rra_appendices.Par.0001.File.amended_bch_f12_14_rra_appendices.pdf

[3] Newfoundland and Labrador Hydro Depreciation Study. Pages III-4 & III-5 (September 7, 2011)
http://www.pub.nf.ca/applications/NLH2012Depreciation/files/applic/NLH2012DepreciationApplication.pdf

Figure 6



While Manitoba Hydro could implement a level of componentization at a much more granular level together with use of an ASL depreciation methodology, the increased administrative costs would have to ultimately be borne by customers and this is unnecessary as comparable results can be achieved with use of ELG as proposed by Manitoba Hydro.

2.2.4 Changes to Manitoba Hydro's Depreciation Methodology are required for IFRS Compliance

Mr. Bowman's evidence claims that Manitoba Hydro has overstated the degree to which accounting standards are driving the changes that have been proposed by the Corporation. Under IFRS, per IAS 16, Property Plant and Equipment is treated as follows:

> ***43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately.***
>
> *45 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.*
>
> *46 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.

Either ASL or ELG can be employed by an entity in a manner that is IFRS compliant, but the implementation details must differ depending on the methodology employed.

The ELG procedure specifically considers the expected service life of each individual asset in the calculation of the desired annual depreciation charge and depreciation rate. As such, it embodies the necessary estimation techniques to allow for grouping of assets with differing expected service lives.

The ASL procedure uses an averaging approach, and as such, it is necessary to define depreciable components quite narrowly in order to meet the IFRS requirement that a group of assets is depreciated in a way that appropriately reflects the useful life of the included parts. For Manitoba Hydro, an IFRS compliant ASL implementation would require a significantly greater degree of componentization in order to segregate parts with longer or shorter expected lives than the average.

2.2.5 There is No Need for a Separate Set of Regulatory Financial Statements Under the Cost of Service Rate Setting Methodology

Mr. Bowman's evidence contends that Manitoba Hydro has not pursued or identified any options in the current filing to mitigate the rate impacts of the accounting changes that have been made to date or are expected upon the transition to IFRS. Mr. Bowman acknowledges that Manitoba Hydro has limited options in terms of financial reporting frameworks other than IFRS, but goes on to recommend that in the event that rate-regulated accounting is not allowed for financial reporting purposes that Manitoba Hydro should provide the PUB with "regulatory" statements and calculations as an alternate to the IFF to assess rate requirements. Mr. Bowman suggests that such regulatory statements would provide for the following for rate-setting purposes:

- DSM expenditures would continue to be deferred and amortized;
- Overhead capitalization practices for the 2008-2010 period would continue;
- Net salvage from depreciation would be eliminated
- The Average Service Life method of depreciation would continue

- Long-term debt for projects not in service and AOCI be removed from the Debt:Equity ratio.

Mr. Bowman's assertion that Manitoba Hydro has not pursued any mechanism to mitigate the rate impacts of accountings changes is not correct. Manitoba Hydro has reviewed its financial reporting options but has limited options given that Public Sector Accounting Board (PSAB) standards require that government related business enterprises such as Manitoba Hydro adopt IFRS for financial reporting purposes. However, Manitoba Hydro has been making any changes that are necessary and permitted under CGAAP gradually over the past number of years in an effort to transition them into customer rates and moderate the impact on customers. Manitoba Hydro has deferred the implementation of IFRS for three successive years as permitted by the AcSB and continues to monitor the developments at the IASB with respect to rate-regulated accounting to ensure that when it does transition to IFRS it is with the lowest possible impacts to customers.

Mr. Bowman does not appear to recognize that it is not necessary to resort to a separate set of regulatory financial statements under the cost of service rate setting methodology that is used to set electric rates in Manitoba. Unlike the rate base/rate of return methodology that is used to set rates in other jurisdictions, the cost of service approach used in Manitoba does not determine rates based strictly on changes in costs and an established capital structure and return on equity. Rather the cost of service methodology coupled with Manitoba Hydro's approach of implementing regular and reasonable rate increases has the flexibility to recognize changes in costs and levels of retained earnings and transition these changes into rates gradually over time.

The success of this approach is evidenced by the fact that despite significant decreases in net extraprovincial revenues and increases in costs due to accounting changes that have been forecast between IFF09 and IFF12, Manitoba Hydro has maintained the required rate increases at around the 3.5% level in the Test Years. This demonstrates Manitoba Hydro's continued commitment to utilize a cost of service rate setting methodology with regular and reasonable rate increases to ensure the maintenance of an adequate financial structure over the long-term. These approaches serve to protect customers from sudden or large rate increases and make a separate set of regulatory financial statements unnecessary.

Manitoba Hydro observes that Mr. Bowman evaluates each of the proposed accounting changes in isolation and adopts those that decrease costs while rejecting changes that increase costs as not being consistent with the hydro-electric business. In contrast, Manitoba Hydro has a more balanced approach to this issue and has evaluated the overall changes that result from the implementation of IFRS and resulting impacts on rates. The following table (Figure 7) summarizes the projected impact of the transition to IFRS on electric operations balance sheet and income statement in 2014/15 in IFF12:

Figure 7

IFRS Impacts - Electric Operations
Increase / (Decrease)

(Millions of $)	**Retained Earnings at April 1, 2014**	**Net Income 2014/15**
Power Smart Programs	(172)	7 *
Site Remediation	(32)	(1) *
Acquisition (Centra & Manitoba Hydro)	(19)	1 *
Regulatory Costs	(2)	1 *
Capital Taxes	-	3
Administrative Overhead and Other	(36)	(36)
Pension & Employee Benefits	(21)	4
Removal of Net Salvage Depreciation	60	63
Change to Equal Life Group Depreciation	(34)	(36)
Total IFRS Impact	**(257)**	**5**

*Net income amounts for rate-regulated accounts include the additional operating & administrative expense net of the offsetting reduction to amortization expense.

As the table demonstrates, the impact on electric net income of all of the proposed changes is minimal and will not impact the required electric rate increases. While the impact on retained earnings in the year of transition is more significant, this can be accommodated within the cost of service rate setting methodology without the need for near-term compensating rate increases. The response to PUB/MH I-78(b) demonstrates that the debt to equity ratio of a scenario that assumes the continuation of rate-regulated accounting converges with the MH11-2 forecast which assumed that rate-regulated accounting would be discontinued, within a ten year period to 2021/22. This demonstrates that the transition to IFRS will only result in timing differences with respect to the recognition of costs. The write-off of rate-regulated accounts will have minimal impact on cumulative retained earnings once the 10 year amortization period has elapsed. The transition to IFRS should not trigger the requirement for a separate set of regulatory financial statements for rate-setting purposes.

One of the benefits of the cost of service rate setting methodology employed in Manitoba is that the PUB uses the same set of general purpose financial statements and information to set rates as Manitoba Hydro, the Manitoba Hydro-Electric Board and other external users of the statements (such as credit rating agencies) for their purposes. This reduces the potential confusion associated with different users looking at multiple sets of financial information to make decisions, evaluate financial performance and assess rate requirements and improves the transparency of the rate setting process by aligning the basis used to set rates and report results. As an example to support this view, one need look no further than Mr. Bowman's recommendation to remove the long-term debt associated with new generation projects that are not yet in service from the debt to equity ratio calculation. Mr. Bowman's proposed calculation is theoretical in nature and could result in the PUB having a very different assessment of the financial position of the Corporation than any other user of the financial statements. Given that one of the purposes of regulation is to ensure the financial integrity of the utility for the benefit of the ratepayer, having such a theoretical calculation that reflects only a portion of the Corporation's operations is at best confusing and potentially misleading.

In addition, there is significant administrative costs associated with reconciling between the different sets of financial information and maintaining duplicate transactional accounting that would be necessary to produce reliable and complete regulatory reporting. This would simply add to the regulatory compliance costs that customers ultimately must bear without any additional benefit to them.

3.0 DEMAND SIDE MANAGEMENT

3.1 Manitoba Hydro's Demand Side Management Activities

In this section Manitoba Hydro addresses the evidence of Mr. Phillipe U. Dunsky and Mr. Paul Chernick with respect to Manitoba Hydro's Demand Side Management (DSM) activities. Mr. Dunsky's evidence suggests that Manitoba Hydro's DSM efforts are modest compared to those of many other North American jurisdictions (page 44) and that Manitoba Hydro is abandoning its energy efficiency efforts based upon decreasing DSM targets over the next 15 years as presented within Manitoba Hydro's Power Smart Plan. Mr. Dunsky's analysis is primarily based on a comparison of Manitoba Hydro's DSM efforts to other efforts being made in North America using a savings ratio metric. Mr. Chernick comments that Manitoba Hydro should adopt the Total Resource Cost (TRC) or a modified TRC test in program design and cost effectiveness screening (page 49) as Manitoba Hydro's current approach is limiting DSM in Manitoba.

Contrary to Mr. Dunsky's characterization, Manitoba Hydro continues to be a recognized leader in energy conservation and the Corporation continues to be committed to pursuing available energy efficient opportunities which are economic. Evidence of Manitoba Hydro's reputation is exemplified by the following:

- International Energy Association – Manitoba Hydro's Power Smart Residential Loan was selected to be included as a Canadian example of best practice in an upcoming report as a result of the International Energy Agency's international review of innovative and exemplary energy efficiency programs (Interview completed in June 2012).

- Natural Resources Canada Office of Energy Efficiency – Manitoba Hydro was asked to present the Power Smart Residential Loan Program for a nationwide webinar for on-bill financing (January, 2012).

- Ontario Geothermal Association – Manitoba Hydro was invited as a guest speaker to highlight Power Smart's long history with the geothermal industry including present day programs as well as the strategies employed early in the adoption cycle of geothermal to assist the industry in ensuring the technology as a viable heating alternative in the Manitoba market (November, 2011).

- Numerous consultations on commercial and residential Power Smart program design and marketing with other utilities and governments including SaskPower, Hydro Quebec, Efficiency New Brunswick, BC Hydro, Newfoundland and Labrador Hydro, Xcel Energy, City of Toronto, Ontario Ministry of Energy, ESource, Baltimore Gas and Electric and Climate Change Central. Manitoba Hydro's expertise has been sought for several of its leading edge programs including Commercial Building Optimization, Commercial New Construction, CFL School Program, Commercial Refrigeration, Fridge Retirement Program, Water and Energy Saver Program and several more.

Manitoba Hydro agrees that using a savings ratio metric in general is valid for comparing energy conservation efforts between regions with similar load characteristics and having similar marginal cost considerations. However the savings ratio metric can produce misleading conclusions when comparing DSM efforts with regional load differences and significant marginal cost differences. In the report "Leadership in Energy Efficiency – Comparing Manitoba Hydro's Power Smart with Leading North American Strategies" undertaken in 2009, Mr. Dunsky cautions that conclusions drawn from benchmarking must be done in consideration of varying load and regional differences; and that conclusions should not be drawn solely upon benchmark metrics as it may lead to misleading and ambiguous results[4].

Manitoba Hydro recognizes Mr. Dunsky's attempt to find comparison regions that would reflect similar constructs as Manitoba. However, Manitoba Hydro would assert that in his selection Mr. Dunsky is oversimplifying the influence of market differences and has understated of the influence of the combined effects of these and other market characteristics. Manitoba Hydro believes it is important to recognize the influence of these market differences. To demonstrate this, Mr. Dunsky states on page 20 of his evidence that "climate doesn't appear to be a determining factor as far as planned DSM savings are concerned" and that "while it is true that Manitoba, with the harshest climate, has the lowest savings ratio by far, B.C., with the mildest climate in the group, has the second-lowest savings ratio". He later states in his response to PUB/CAC & GAC 9 (c) that "the average residential GWh load in Minnesota is slightly lower than that in BC, despite Minnesota being nearly twice as cold as BC". Mr. Dunsky also states that penetration of electric space heating is an important factor but does not investigate further as possibly influencing the outcomes for BC and Minnesota. We would note that although Minnesota is nearly twice as cold as BC, the percentage of residential customers with electric heat is half of that in BC (15% in MN versus 31% in BC). Based upon this, one would expect that Manitoba having the harshest climate (4517 DDH) combined with a high percentage of electric space heating (42%) would potentially influence the metrics.

Manitoba Hydro recognizes that some regions are pursuing higher levels of energy savings than what is being planned under the Corporation's 2011 Power Smart Plan. Manitoba Hydro notes that this reflects regional differences (i.e. each region has different marginal cost values, different economic energy efficient opportunities and different policies driving DSM efforts). In a number of cases, the marginal cost in a region is much higher than Manitoba Hydro's marginal cost and as such, it is expected that these regions will have significantly more economic opportunities. Manitoba Hydro's Power Smart Plan is based on its unique situation of:

- having a marginal cost value which is considerably lower than regions such as British Columbia, Nova Scotia and Vermont;
- having a marginal cost value where the export electricity market accounts for a significant component of the marginal cost value (i.e. as opposed to deferred new

[4] "Leadership in Energy Efficiency – Comparing Manitoba Hydro's Power Smart with Leading North American Strategies", a Dunsky Energy Consulting report commissioned by Manitoba Hydro, October 1, 2009, page 27.

generation costs);

- having a load characteristic consisting of a large diverse industrial load, significant electricity use for space and water heating, and high heating degree days.

Manitoba Hydro recognizes that DSM targets presented in the 2011 Power Smart Plan are declining but would assert that this is a reflection of Manitoba Hydro's, consistent long term engagement in DSM and the diminishing availability of economic energy efficient opportunities remaining in the Manitoba market. Manitoba Hydro agrees with aggressively pursuing energy efficiency opportunities; however, the Corporation believes it is important to primarily pursue those opportunities which are economic.

There are two high level processes undertaken in developing an overall DSM program: a screening process and a program design process. The screening process is generally undertaken without consideration for who benefits and who pays the costs. This screening exercise is undertaken to identify economic energy efficient opportunities. It is appropriate to use either the Marginal Resource Cost (MRC) test, a modified Total Resource Cost (TRC) test or Societal Cost Test (SCT) for this purpose. Once the economic DSM opportunities are identified, then a separate exercise is undertaken to determine which program design is best to pursue in support of the DSM opportunity.

Manitoba Hydro uses the MRC test which is a simplified version of the TRC test; however program administration costs are excluded under the MRC test. As such, the MRC test will "screen in" more opportunities than a TRC test. Similarly, a SCT test will "screen in" more opportunities than a TRC test as the SCT includes additional benefits, many of which are very difficult to measure (e.g. comfort). Given program administration costs (i.e. those costs which are excluded in a MRC test) can be a significant component of an overall Power Smart budget, Manitoba Hydro is of the view that the use of a MRC test for screening energy efficient opportunities effectively achieves the same result as using a SCT. Further, Manitoba Hydro

- includes measureable non electricity benefits such as water savings within the MRC;
- includes the value of GHG emissions (i.e. this value is included within the forecast price of electricity to be sold in the export market; the value of export electricity makes up a significant component of Manitoba Hydro's avoided cost); and
- considers any opportunities which may be close to passing the MRC so the use of this test is not a hard "go/no-go" decision.

In the program design process, a number of metrics (the modified TRC test, Levelized Utility Cost (LUC) test, participant payback period and Rate Impact Measure (RIM) test) are used in aggregate to determine which program design will be most appropriate to undertake. The simple participant payback metric provides a high level indication of the economic benefit for a DSM option for an eligible customer. To assess the impact to the utility (i.e. ratepayer), Manitoba Hydro uses both the RIM and the LUC metrics.

The RIM test is a simple test which provides an indication of the directional impact and the general magnitude DSM programs have on rates, recognizing the latter is very rudimentary. If the RIM test is equal or close to one, then non-participants are relatively indifferent economically.

The LUC metric provides a more useful measure of the relative value or cost to the utility (and all rate payers) as this measure provides a unit cost for achieving the energy savings. This measure is generally used to compare the impact of DSM programs to the marginal cost less the lost domestic revenue (i.e. real economic impact to the utility (ratepayer)). Due to the complexity of Manitoba Hydro's marginal cost value, Manitoba Hydro emphasizes that caution must be exercised in using the LUC at face value. Manitoba Hydro's annual marginal value is an average of the underlying values which vary between seasons and between on-peak and off-peak time. Further, the marginal value is composed of both demand and energy values. For this reason, it is critical that Manitoba Hydro use both the RIM test in conjunction with the LUC test in assessing the real economics of each DSM option.

In the response to PUB/CAC & GAC 14, Mr. Dunsky is suggesting that in the absence of DSM efforts, ratepayers would need to spend the difference between Manitoba Hydro's avoided cost (i.e. 8.5 cents/KWh) and the levelized cost of achieving DSM savings (e.g. 1.5 cents/KWh) which is 7.0 cents/KWh. Mr. Dunsky's analysis excludes critical factors which leads to a misrepresentation of the true costs to ratepayers of reducing utility spending in DSM.

To assess the cost to the ratepayer, all benefits and costs must be considered. The following analysis (Figure 10) presents the net costs of reduced DSM spending to the utility (ratepayer), participating customers and from an integrated resource perspective using the model utilized by Mr. Dunsky in his response to PUB/CAC & GAC 14 (note: assumptions include having a marginal cost of 8.5¢/kWh, a DSM LUC of 1. 5¢/kWh, a domestic rate of 7¢/kWh. and a participant DSM contribution of 3.3¢/kWh)

Figure 8

Utility Perspective (Ratepayer)	**Unit Cost**
Reduction in DSM Spending (Utility)	(1.5 ¢/kWh)
Utility Lost Opportunity Cost	
Lost Opportunity Marginal Value of Electricity	8.5 ¢/kWh
Inflow Revenues	(7.0 ¢/kWh)
Net Utility Lost Opportunity	1.5 ¢/kWh
Net Cost to Ratepayers of reducing DSM Spending	**0.0 ¢/kWh**

Participating Customer Perspective	**Unit Cost**
Reduction in DSM Spending (Participating Customer)	(3.3 ¢/kWh)
Utility Bill Impact (lost opportunity of avoided utility bill) [2]	7.0 ¢/kWh
Net Cost to Participating Customer of reducing DSM Spending	**3.7 ¢/kWh**

Integrated Utility/Customer Perspective (Total Resource Cost)	**Unit Cost**
Reduction in DSM Spending (Utility)	(1.5 ¢/kWh)
Reduction in DSM Spending (Participating Customer)	(3.3 ¢/kWh)
Lost Opportunity Marginal Value of Electricity	8.5 ¢/kWh
Net Integrated Resource Cost of reducing DSM Spending	**3.7 ¢/kWh**

By taking a comprehensive analysis, it is clear that the utility (i.e. the ratepayer) is economically indifferent and the participating customer is worse off by not implementing the DSM measure by 3.7 ¢/kWh. In this case, the eligible customer has a significant incentive to participate in the DSM opportunity. Although the overall analysis is crude, the general message is clear and consistent with Manitoba Hydro's assessment of its Power Smart Plan. Based on this analysis, it is evident that pages 34-35 and 38 of Mr. Dunsky's direct testimony, page 27 of Mr. Chernick's direct testimony and responses to PUB/CAC & GAC 18 and PUB/GAC 12(a) are similarly misleading.

In both Mr. Dunsky's and Mr. Chernick testimony (page 33 and pages 23-25 & 32, respectively) and in responses to PUB/CAC & GAC 16, and PUB/GAC 10, it is suggested that Manitoba Hydro is not using the appropriate tests in screening its DSM programs. Manitoba Hydro would assert that the Corporation is using the DSM metrics appropriately and maintains that all of the metrics used in the development of the Power Smart Plan are both useful and valuable in designing efficient and effective programs. Mr. Chernick's and Mr. Dunsky's comments appear to be a result of not fully understanding how and when Manitoba Hydro uses each of the DSM metrics. For example and as previously stated, Manitoba Hydro does not use the RIM test to screen DSM opportunities. Further the MRC test is a reasonable and can be a more inclusive test relative to the modified TRC and SCT for screening purposes.

Contrary to Mr. Chernick's testimony, the RIM test is a valuable metric for Manitoba Hydro in assessing the economics of its DSM programs from a utility/ratepayer perspective. Manitoba Hydro does not screen out energy efficient opportunities using either the RIM or the LUC Test. These tests are only used by Manitoba Hydro to assist in program design decisions including how aggressive to pursue a particular opportunity.

Manitoba Hydro agrees with Mr. Dunsky's suggestion that the Corporation's Power Smart Plan is conservative in the sense that only identified economic opportunities have been included. Manitoba Hydro recognizes that some new opportunities will likely surface in the future and the Corporation intends to include these opportunities once they are identified as being economic within the Manitoba market.

Manitoba Hydro's 2011 Power Smart Plan involves pursuing all energy efficient opportunities which have been identified as being economic in Manitoba. In an effort to identify additional opportunities, Manitoba Hydro is currently in the process of undertaking a DSM market potential study. The results of this study will be used as a basis for developing Manitoba Hydro's future DSM plans. In addition, with the passing of the Energy Savings Act, Manitoba Hydro will be consulting with the Minister responsible for Manitoba Hydro in establishing future DSM targets.

To ensure Manitoba Hydro's approach to setting targets is aligned with available opportunities, the Corporation also monitors leading utilities and the programs being offered by these utilities throughout North America. The results of these comparisons demonstrate that, Manitoba Hydro has a comprehensive and aggressive energy conservation effort. For example, a review of the utilities presented by Mr. Dunsky has found numerous similarities within the DSM portfolios offered in the residential, commercial and industrial sectors.

The following table (Figure 9) compares DSM offerings for residential markets.

Figure 9

Residential Programs/Offerings	**Manitoba Hydro**	**Quebec**	**British Columbia**	**Nova Scotia**	**Mass.**	**Minn.**	**Vermont**
Building Envelope	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Water Heat/Conservation	Yes	No	Yes	Yes	Yes	Yes	No
Lighting	Ended	Yes	Yes	Yes	Yes	Yes	Yes
New Construction	Redesign underway	Yes	Yes	Yes	Yes	Yes	Yes
Appliances	Ended	No	Yes	Yes	Yes	Yes	Yes
Appliance retirement	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Financing	Yes	No	Yes -pilot	Yes – 3rd party	Yes	No	No
Energy Audits	Yes	Yes	Yes	Yes	Yes	Yes	Yes
HVAC	Financing	Yes	Yes	Yes	Yes	Yes	Yes
Lower Income	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Geothermal	Yes	Yes	Yes	Yes	No	Yes	No
Solar Thermal	Financing	No	Yes	Yes	Financing	Yes	No
TVs/Electronics	No	No	No	No	Yes	No	No
Swimming Pool Pump	No	Yes	No	No	Yes	No	Yes
Electricity Meter Loan	No	No	No	No	No	No	Yes
Fuel switching to natural gas or biomass	No	No	No	Yes	No	No	Yes
Programmable Thermostats	Ended	Yes	Yes	Yes	Yes	No	No
Solar Photovoltaic Systems	No	No	No	No	No	Yes	No
School Education	Yes	No	No	No	Yes	Yes	Yes

Based on this comparison, it is evident that Manitoba Hydro is pursuing a comprehensive list of energy efficient opportunities within the residential market. Further, Manitoba Hydro continues to explore and evaluate additional opportunities which could be pursued (e.g. LED lighting is currently being assessed for future opportunities).

The following table (Figure 10) compares DSM offerings for commercial markets.

Figure 10

Commercial Programs/Offerings	Manitoba Hydro	Quebec	British Columbia	Nova Scotia	Mass	Minn.	Vermont
New Construction	Yes	Yes	Yes	Yes	No	Yes	Yes
Lighting	Yes	Yes	Yes	Yes	Yes	Yes	Yes
HVAC	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Building Envelope - Retrofit	Yes	Yes	No	No	Yes	Yes	Insulation only
Appliances	Yes	No	Yes	Yes	Yes	Yes	No
Refrigeration	Yes	Limited to refrigerant reduction/ change, or heat reclaim	Yes	Yes	Limited	Limited	Yes
Custom Opportunities	Yes	Gas only	Yes	Limited	Yes	Yes	No
Heat Pumps (geothermal and air-source, etc)	Yes	No	Limited, demo only.	Limited	Yes	Water source only.	No
Information Technology	Yes	No	No	No	No	Yes	No
Retrocommissioning & Recommissioning	Yes	No	Limited, investigation only.	No	Yes	Yes	No
Energy Management	Redesign underway	No	Yes	No	No	Limited	No
Targeting Small Business	Redesign underway	No	No	Yes	Yes	Yes	No
Financing	Limited. PAYS in Design	Limited, demo only.	Limited	Yes	Yes - 3rd party	Yes	Yes
Energy Audits	Limited	No	Limited to largest customers	Limited	Limited	Yes	Yes
Building Certification	Yes	No	No	No	No	Yes	No
Variable Speed Drives, Efficiency Controls	Yes–Custom	No	Custom	VSD only	Yes	Yes	No
Solar	Yes–Custom	Yes	No	Yes	Custom	Yes	Yes
Agricultural	Limited	No	Limited	Limited	No	Limited	No
Compressed Air	Yes	No	No	No	Yes	No	No
Pumps and Motors	Yes	No	Pump assessment only	No	Motors only	No	No
Ice and Curling Rinks	Yes–Custom	Yes	Yes	No	No	No	No

Based on this comparison, it is evident that Manitoba Hydro also is pursuing a comprehensive list of energy efficient opportunities within the commercial market. Similar to the residential market, Manitoba Hydro continues to explore and evaluate additional opportunities which could be pursued in the commercial market (e.g. commercial PAYS financing to assist in hard to reach targeted market sectors such as multi-residential, institutional and small commercial).

For the industrial sector, a broad comparison indicates that Manitoba Hydro's Power Smart program targets similar opportunities to those being pursued in the six jurisdictions referenced in the previous tables. Manitoba Hydro's industrial DSM efforts provide financial incentives for feasibility studies. Opportunities are pursued for all technologies that contribute verifiable electric and natural gas savings. Technologies that have been supported to date include; variable frequency drives, compressed air systems upgrades, energy management systems, refrigeration, HVAC, heat pumps, energy recovery, boilers, hi-efficiency motors, building envelope upgrades, steam trap assessments, process equipment and pipe insulation.

On page 24 of Mr. Dunsky's written testimony, he agrees that sustained high levels of savings are a challenge; however Mr. Dunsky testifies that other technologies will emerge to create new opportunities. Mr. Dunsky states "At the same time that codes and standards are being adopted and the potential of some existing measures are being depleted, new technologies and program approaches are creating new opportunities to replenish the DSM pool. For instance, while the potential for traditional water heater measures (blankets, insulation, low-flow showerheads) have largely dried up due to the success of past DSM programs and standards, new measures are taking their place, including gray water heat recovery, heat pump water heaters, and solar water heaters." Further in his testimony (page 35 -36), Mr. Dunsky highlights additional opportunities under residential lighting through CFLs and LEDs, the use of ductless heat pumps, particularly newer inverter-driver models, and the use of bill comparison feedback/benchmarking initiatives. Manitoba Hydro notes that Mr. Dunsky's recommendations are provided without mention of the cost effectiveness of these measures from a resource perspective or the applicability to the Manitoba marketplace.

Manitoba Hydro is well aware of the measures mentioned by Mr. Dunsky and these opportunities have been previously investigated or are being assessed for possible inclusion in the Corporation's Power Smart plan. For example:

- Gray water (or drain water) heat recovery is facilitated through Manitoba Hydro's on-bill financing and is one of the measures being considered as part of the revised Power Smart New Home standard.

- Heat pump water heaters are not suited to Manitoba's marketplace. The technology "pulls" heat out of the space they are located in and "puts" that heat into the water. This technology is popular in more moderate climates and in regions where the water heater is not located in a conditioned space. In Manitoba due to our long heating season, water heaters are located inside our homes and buildings. In Manitoba Hydro's engineering assessment, energy savings from this application would be marginal and the conserved energy would not be economic for the customer or the utility.

- Solar water heaters are not cost effective in Manitoba under current costs and this technology is not projected to be cost effective within the near term.

- In December 2011, Manitoba Hydro discontinued its CFL lighting program after having a long running and successful CFL in-store incentive program. Through the Power Smart CFL program, it was estimated that over 65% of Manitoba households had installed CFLs and it was expected that there would continue to be additional market penetration without an ongoing incentive program. As such, Manitoba Hydro's strategy for promoting CFLs changed from offering an incentive program to a strategy of supporting the energy efficient opportunity through a customer information campaign. General use LED lamps are not cost effective under current pricing and a substantial decrease in cost is required before these measures will be cost effective from a resource perspective. In addition, concerns about luminous efficacy, validation of the longer life (given short warranties offered), and proper recycling need to be addressed. Manitoba Hydro promotes LEDs in the residential sector as part of the customer-information based approach and continues to monitor the market for potential future opportunities.

- As outlined in Manitoba Hydro's response to CAC-GAC/MH II-7(c), Manitoba Hydro is testing the performance of ductless heat pumps. The units have a high installed cost, estimated to be approximately $14,000; $7000 - $8000 for the unit plus labour and materials for installing electrical and refrigerant piping and condensate drain piping throughout a house. Based on Manitoba Hydro's engineering assessment, the installed cost is not offset by the estimated energy savings from the average home using electric baseboard heating which is 1100 sq. ft in Manitoba. Based on vendor discussions, to date customers installing these types of systems reside in larger older homes with natural gas boilers in central Winnipeg (Wolseley and River Heights areas) and have been purchasing them for air conditioning; upgrading to the variable flow systems means customers are essentially switching a portion of their heating requirements to electricity. Based upon Manitoba Hydro's 2009 Residential Energy Use Survey, customers with electric baseboard heating systems who have air conditioning (41%), predominantly install the less costly window air conditioning units (96%). Manitoba Hydro intends to continue to monitor the performance and costs of air source heat pumps.

- Manitoba Hydro has investigated the potential for capturing energy savings through bill comparison services, including detailed discussions with one North American service provider. Based upon these discussions, this opportunity was not considered economic at this time (e.g. the average estimated potential energy savings associated with this initiative were estimated as having a one year useful life only with on-going communication and investment to maintain the energy efficient behaviours). Manitoba Hydro is currently monitoring the results of this opportunity within other regions and intends to maintain this option as a possible opportunity to consider in the future.

In conclusion, Manitoba Hydro maintains that its Power Smart Plan involves pursuing all available economic DSM opportunities given consideration to Manitoba's load characteristics and Manitoba Hydro's marginal values, including the detailed underlying makeup of the marginal values. Manitoba Hydro remains committed to searching for additional opportunities and this is evident in the Corporation's ongoing efforts, including undertaking a market potential study, reviewing efforts and programs being undertaken by other regions and current efforts assessing potential opportunities (e.g. drain water heat recovery, LEDs, New Homes). In addition, Manitoba Hydro's use of the MRC is appropriate for screening potential DSM measures and is a reasonable proxy for using alternative tests such as a Modified TRC or SCT test. The use of RIM, LUC, and simple participant payback analyses, in addition to the Modified TRC/SC cost effectiveness tests, are appropriate metrics for assessing program designs.

3.2 Estimate of Environmental Values

In a number of instances, the Direct Testimony of Mr. Chernick suggests that Manitoba Hydro does not properly recognize the significance of environmental considerations in its analysis. This is incorrect.

For example, at page 19, lines 3-5 of his evidence, Mr. Chernick indicates that Manitoba Hydro includes the value of reduced greenhouse gas emission for natural gas conservation but does not include any environmental value for electricity conservation. This is not correct, nor does it reflect the text of the Power Smart Report that it appears to quote (Appendix 7.1, Appendix F, page 4).

The value of greenhouse gas emissions is included in the evaluation for both natural gas and electricity DSM programs. The marginal costs for electricity conservation programs are based on the Export Price Forecast which includes expectations of the value associated with greenhouse gas emission avoidance in the Midwest region.

Mr. Chernick also asserts that it is not reasonable to assume that the sales prices for Manitoba Hydro's exports reflect the value of carbon emissions (page 19, lines 13-15). This is also inaccurate. Parties in negotiations for these types of contracts consider what the electricity prices will be over the life of the contract and must therefore consider all pricing factors identified above, including expectations of greenhouse gas emission costs.
Mr. Chernick states that "the fuel-switching report is entirely a financial analysis without any valuation of environmental effects" (page 20, lines 5-6). This is incorrect, since the quantification of greenhouse gas implications of different fuel choices and technologies is a key focus of this report.

3.3 Accelerated DSM and Need for New Generation

Mr. Dunsky's response to PUB/CAC&GAC 18 comments on the ability to defer Keeyask to 2031/32 under an accelerated DSM program which yields a savings of 1385 GWhs by 2019/20. Manitoba Hydro disagrees with this statement.

Based on the No New Generation System Firm Energy Demand and Dependable Resource tables in the 2011/12 Power Resource Plan (pages 34-35), additional DSM savings of 1385 GWhs would defer the need for new energy resources until 2024/25 (shortfall of 1651 GWhs). An additional 3000 GWhs would be required to defer the need for new resources to 2031/32 (shortfall of 4400 GWhs).

In addition, it is acknowledged in the response provided by Mr. Dunsky to PUB/CAC&GAC 18, that capacity was not a consideration in deriving the deferral dates. Based on the 2011/12 Power Resource Plan, new capacity resources are required in 2021/22. To defer this date to 2031/32 would also require in the order of 800 MW of DSM capacity savings. Mr. Dunsky's evidence does not address if or how these required capacity savings will be found.

4.0 FUEL SWITCHING REPORT

This section addresses the written evidence of Mr. Paul Chernick on behalf of GAC regarding Manitoba Hydro's report on the "Economic, Load and Environmental Impacts of Fuel Switching in Manitoba" (the Fuel Switching Report).

Mr. Chernick states on page 32, lines 9-11 of his written testimony that *"Hydro's fuel-switching report indicates a serious market problem, which should be addressed through a combination of rate design, DSM programming and terms and conditions for new and expanded service."*

As Manitoba Hydro outlined in its report "Economic, Load, and Environmental Impacts of Fuel Switching in Manitoba", there are benefits when customers use natural gas for space and water heating purposes from the customer, utility, global environmental, and in most cases of the provincial leakage perspectives. Based on the 2012 Load Forecast, Manitoba Hydro is projecting a shift overall towards the use of conventional electric space heating from 34% in 2011/12 to 37% of residential customers in 2030/31. A more significant shift is expected to occur in fuel use for water heating due to technical and cost considerations primarily in new homes with electric water heating, which is forecast to grow from 55% of residential customers in 2011/12 to 79% of residential customers in 2030/31.

Manitoba Hydro believes that if customers are well informed, they will make the best choice for their situation and in most cases will choose natural gas when available. In September 2012 Manitoba Hydro initiated a Heating Education Campaign to enhance customers' awareness of factors relevant to their decisions on space and water heating. The campaign includes a multi-faceted approach targeting homeowners, HVAC suppliers and installers, homebuilders, commercial builders and property developers. The campaign will further build in 2013 with the development of new online resources, which can be accessed through Manitoba Hydro's website and social media networks. Advertising in local newspapers, brochures and bill inserts will be ongoing. Manitoba Hydro also has convenient financing programs, including the PAYS program, which can assist customers choosing to replace or upgrade their space and water heating systems.

Manitoba Hydro will continue monitoring market trends in fuel choices and will assess the impact of its educational efforts on an ongoing basis. The Corporation's educational efforts will be adjusted accordingly and further considerations may be given to using additional intervention tools such as service extension policies, rate design and incentive programs.

5.0 MARGINAL COST ESTIMATES

This section deals with the marginal cost evidence provided by Mr. Chernick on behalf of GAC. Specifically, it addresses Mr. Chernick's assertions about how marginal costs in Manitoba Hydro's system are calculated and what factors are considered in the calculation of those costs.

5.1 Generation Plant Investment Costs are Considered

In reference to the direct testimony of Mr. Chernick at page 11 lines 20-24 regarding the basis of the marginal cost/value of generation, Manitoba Hydro clarifies that, it does use separate values for capacity and energy, as stated in the response to CAC-GAC/MH I-4(b). Hence the marginal generation cost estimates consider the value on the export market of both energy and generation capacity. The generation capacity component represents the cost of carrying the generation plant investment.

5.2 Methodology for Marginal Transmission and Distribution Costs

This section addresses the written evidence of Mr. Chernick at pages 13-14 with respect to the analysis of marginal transmission and distribution costs.

Manitoba Hydro has been reviewing aspects of the methodology used to determine transmission and distribution marginal costs, which represent approximately 20% of the total generation, transmission and distribution marginal costs. This review is expected to address the concerns raised regarding treatment of load growth and overhead transformers.

With respect to the O&M associated with load-related projects, Manitoba Hydro recognizes the transmission and distribution marginal costs do not include potential operation and maintenance costs on the deferred cost, but notes that in most cases the O&M costs for the project would be negligible, contributing around 2% to the overall marginal cost number.

The Roblin South Station 230-KV Reactor was not included in the marginal cost calculation as it was installed for voltage control on the interprovincial interconnection transmission line between Manitoba and Saskatchewan. As this particular installation was driven by the need for voltage control and not the prevention of thermal overloading, the costs of this reactor were determined to be unrelated to increases in demand.

6.0 NEED FOR WUSKWATIM

This section addresses the question of the need for Wuskwatim raised by Mr. Bowman in response to PUB/MIPUG I-7.

Undertaking #22 of the 2010 GRA provides the following context:

> "during the "need for and alternatives to" process in 2003 it was stated that, although the advancement of the Wuskwatim G.S. was being justified primarily on the basis of obtaining profits from new export revenues, there were many other factors that provided justification for early construction. At that time it was stated that one such additional justification was that it provided a source of generation should the Manitoba domestic load grow at a rate higher than forecast. In fact, subsequent to 2003 there was a significant increase in the load growth such that with the 2007/08 load forecast Wuskwatim G.S. would be required by 2012/13 to serve existing load requirements. It was only in the last three years that the load growth has decreased to the point where Wuskwatim G.S. is not required until 2019/20 from the perspective of the dependable energy criterion."

The 2003 review of the Wuskwatim Generation and Transmission Projects, included a comparison to wind generation. The conclusion of the Commission which conducted this review was "*that the Projects represent a viable alternative and an in-service date of 2010 should be pursued*". Subsequently, Manitoba Hydro, through power purchase agreements, added wind generation to its supply portfolio. Undertaking #22 does not address the addition of wind generation.

To respond appropriately to the question of whether Wuskwatim was in fact required as a new resource to serve Manitoba the removal of Wuskwatim, as well as wind from the supply/demand table is required prior to conducting such analysis. Removing these generation resources results in a persistent shortfall starting in 2011/12 as shown in the table provided in Manitoba Hydro's response to MIPUG/MH II-16(b). These shortfalls would be filled by the Wuskwatim G.S.

7.0 RATE OPTIONS

The purpose of this section is to address Mr. Bowman's evidence with respect to the Curtailable Rate Program (CRP).

7.1 Curtailable Rate Program

Mr. Bowman recommends that the PUB reject Manitoba Hydro's proposed reductions to caps on CRP Option 'A' or 'R' load.

Manitoba Hydro asserts that there is ample evidence that the CRP industrial customers have benefited from the program and existing participants will continue to do so within the proposed caps. Manitoba Hydro explained in PUB/MH II-99(b) why the proposed reductions to Option 'A' and 'R' caps are justified. The following sections expand on Manitoba Hydro's justification for reducing these caps. The following sections also respond to statements provided in Mr. Bowman's written evidence and IR responses.

7.1.1 Low Capacity Prices in Neighbouring Markets due to Capacity Surpluses

Current export market capacity prices continue to be soft due to installed capacity surpluses. MISO's recent Voluntary Capacity Auction (VCA) prices, expressed in $USD/kW/month are provided in table (Figure 11) below. These prices are only a very small fraction of the discount afforded to Option 'A' and Option 'R' load. For 2010/11 period, the VCA cleared at an average price below $0.001/kW month. This is less than 0.1% of the marginal value of capacity used to establish CRP rates. Under these conditions, conversion of additional Firm Service industrial load to the CRP rates would result in a net loss to Manitoba Hydro.

Figure 11

MISO Voluntary Capacity Auction clearing prices for 2009/10 and 2010/11 expressed in $US/kW/month.		
	2009/10	**2010/11**
April	$0.00035	$0.00025
May	$0.00035	$0.00025
June	$0.00500	$0.00035
July	$0.01000	$0.00050
August	$0.01000	$0.00028
September	$0.00300	$0.00025
October	$0.00025	$0.00001
November	$0.00025	$0.00002
December	$0.00100	$0.00010
January	$0.00250	$0.00020
February	$0.00094	$0.00019
March	$0.00050	$0.00010
Average ($US/kW/month)	$0.00285	$0.00021

7.1.2 No Long-term Commitment to Provide Curtailment Service

Manitoba Hydro does not rely on curtailable load in its long-term resource adequacy plans because CRP customers are not obligated to make long-term commitments. Despite this fact, participants in the CRP program benefit from rates that are discounted based on Manitoba Hydro's *long-term* value of capacity. The CRP applies a stable discount to Option 'A' and Option 'R' customers equivalent to 70% of the Reference Discount, which represents Manitoba Hydro's long-term marginal value of capacity[5]. The Reference Discount for 2012/13 is $3.21/kW/month which is orders of magnitude above the current capacity market prices provided in Figure 11.

Manitoba Hydro asserts that the practice of applying a discount based on its long-term value of capacity is already consistent with Mr. Bowman's statement, "it is appropriate to consider future price forecast in the assessment of the CRP value."[6] Manitoba Hydro is not proposing to reduce the discount to CRP customers, rather it recognizes the long-term

[5] The value of CRP capacity is based on 42% of the annualized carrying cost of a simple cycle combustion turbine.

[6] Pre-filed Testimony of P. Bowman for the 2012/13 and 2013/14 GRA submitted on behalf of MIPUG, November 16, 2012, p.5-5.

value CRP load provides and the investments existing CRP customers may have made to be capable of providing this service, and plans to continue the program at the current subscription levels. Manitoba Hydro asserts that, contrary to the cautionary statements expressed by Mr. Bowman[7], continuance of the discount offered to CRP load and maintenance of caps consistent with current subscription levels indicates that Manitoba Hydro does in fact "place value on the long-term or relationships aspects of the program." Manitoba Hydro notes that no new customers have signed on to the program for a number of years.

7.1.3 Manitoba Hydro has decided that additional CRP load is not required to respond to a MISO Maximum Generation Event[8]

As recent as 2011[9], Manitoba Hydro indicated that it was in the process of reviewing the CRP option caps as changes were occurring within the MISO jurisdiction. If a Maximum Generation Event were to occur in the MISO region, MISO may call upon the capacity associated with Manitoba Hydro's capacity backed export sales. In 2011, Manitoba Hydro was considering increasing the Option 'A' curtailable load cap to 400 MW to backstop Manitoba Hydro's Brandon combustion turbines and its gas-fired steam turbines at Selkirk G.S. Manitoba Hydro could use the Option 'A' curtailable load to bridge the period required to start its gas-fired generation.

However, the likelihood of MISO experiencing a Maximum Generation Event is highest in the summer when it experiences its peak load. During this period the Manitoba load is over one-thousand mega-Watts less than its winter peak load and thermal generation is not required to support capacity backed export sales even during a Maximum Generation Event. As a result a decision was made not to increase the CRP Option 'A' cap at this time. Manitoba Hydro made this assessment after the 2011 CRP report was issued.

The current subscription levels of Option 'A' and Option 'R' Curtailable Load are consistent with Manitoba Hydro's needs in the near term and our long term commitment to existing customers. Moving forward, Manitoba Hydro expects to participate in the MISO Annual Capacity Auction. Manitoba Hydro will assess the applicability and economic benefit of using curtailable load to support term capacity sale obligations in this auction or

[7] PUB/MIPUG-I-22(a) and (b), p.2 line 13-23.
[8] An event triggered by an emergency in the MISO jurisdiction.
[9] Manitoba Hydro, Report to the Public Utilities Board on the Curtailable Rate Program, October, 2011, p. 8.

through bilateral contracts. If there is merit to using curtailable load in this manner, Manitoba Hydro may increase limits to Option 'A' CRP load in the future.

8.0 OTHER

This section addresses the written evidence of Mr. Chernick on behalf of GAC with respect to comments regarding the reviewability of Manitoba Hydro's proposals and analysis.

8.2 Reviewability of Manitoba Hydro's Application

At page 4 of his evidence, Mr. Chernick states that Manitoba Hydro "filed its 2012/2013 rate design proposals, including a time-of-use rate for large general service customers, on October 3, 2012." Manitoba Hydro notes that it filed rate schedules for rates to be effective in the 2012/13 fiscal year on July 6, 2012, in its filing of Volume II Application materials. Manitoba Hydro filed rate schedules for the 2013/14 fiscal year on October 3, 2012, including a proposal to implement TOU rates and customer-class differentiated rate increases, following approval by the Manitoba Hydro-Electric Board. By letter dated November 6, 2012, the PUB confirmed that Manitoba Hydro's request for TOU Rates and class-differentiated rate increases would be reviewed separately from the GRA, as part of the Cost of Service Study Review process expected to take place in the spring of 2013. As such, Manitoba Hydro filed revised rate schedules on November 7, 2012 on an across-the-board basis, consistent with Manitoba Hydro's past rate design practices, a practice that is familiar to all parties to this proceeding. All parties will have the opportunity to examine Manitoba Hydro's TOU rate proposal in the process expected to take place in the spring of 2013.

Also on page 4 of his evidence, Mr. Chernick states that "The fuel-switching report was filed…, two months after the initial GRA filing and three years late." The fuel switching report was filed with the PUB in response to directive 17 from Orders 116/08 & 150/08, but does not form part of Manitoba Hydro's General Rate Application. While this report contains future policy implications, it does not have a direct impact on the revenue requirement for the two Test Years in this Application.

At page 31 of his evidence, Mr. Chernick recommends that "the Board should request comments from Hydro and intervenors on the additional documents that should be in the GRA filing requirements", and recommends that "the Board should require that Hydro file its proof-of-revenue tables, bill comparisons, COS studies and marginal cost studies as Excel spreadsheets with all formulas intact."

The Public Utilities Board has been able to fulfill its mandate to set just and reasonable rates for Manitoba Hydro for many years with the existing minimum filing requirements and without access to materials in Excel format. In this proceeding, Manitoba Hydro has agreed to provide, upon request, data only spreadsheets to intervenors wishing to undertake their own analysis. However, the recommendation with respect to filing its proof-of-revenue model, bill comparisons, COS studies and marginal cost studies in Excel format ignores Manitoba Hydro's concerns related to the potentially significant amount of time and effort that would be required to prepare the models to be placed in the public domain, to educate other parties in the use of these models, and to verify alternative scenarios developed by third parties using the models. This recommendation also ignores that some of these models contain commercially sensitive information and the potential infringement on the third-party rights over the models. As such, Manitoba Hydro does not agree with the need for additional filing requirements as recommended by Mr. Chernick.

8.3 Consultation on Cost of Service and Time-of-Use Rate Proposal

In conjunction with this General Rate Application, Manitoba Hydro has already filed evidence with regards to its preferred treatment of its Cost of Service Study and has applied for the differentiated treatment of the rate increases to various customer classes. As part of its rate proposals already filed, Manitoba Hydro sought approval to implement Time-of-Use rates for General Service Large customers, served at levels greater than 30 kV.

As set out in Order 98/12, the Public Utilities Board determined that Cost of Service matters were to be addressed in a separate public hearing process to be scheduled for 2013. Further, by way of its letter dated November 6, 2012, the Public Utilities Board determined that Manitoba Hydro's request for the implementation of both Time-of-Use rates and the application of class differentiated rate adjustments should be considered in the same public hearing process set out for the review of the Cost of Service Study.

Mr. Chernick, in response to MH/GAC (Chernick) – 1, attached correspondence between Mr. Peter Miller and Manitoba Hydro, dated November 25, 2012, in which Mr. Miller proposed four topics for consideration in the public hearing process (and associated consultation sessions with interested parties) to review the Cost of Service, Differentiated

Rates and Time-of-Use General Service >30 kV rates. As set out in this correspondence, the topics, in order of GAC's preference, are:

1. Residential rate structure
2. Non-TOU General Service rate structures
3. General Service TOU rate structures, and
4. Cost of Service issues.

Manitoba Hydro reiterates that it has made application for the implementation of Time-of-Use Rates for General Service >30kV and for the implementation of rate increases on a class-differentiated basis, and that these matters, in conjunction with a review of the supporting Cost of Service Study, are the only matters that should be addressed in the proposed public hearing process and any consultation sessions preceding it. Significant consultation has already been undertaken on the Time-of-Use Rates proposal with both directly affected customers and other interested parties, and a timely and expedient public review should be pursued at the earliest opportunity. Manitoba Hydro would consider the merits of hosting a technical conference regarding its proposed Cost of Service Study prior to any scheduled public hearing, which would provide an opportunity for all parties to gain better understanding of the Cost of Service matters that are to be addressed. This technical conference would not, however, be intended to solicit alternatives to its already-filed proposal.

With respect to other rate design matters, as stated in the response to PUB/MH I-149, Manitoba Hydro has not advanced a plan to implement inverted rates for any customer classes in this Application. Manitoba Hydro has no formal timetable as to the development of an inverted rate structure for any customer classes. Furthermore, in its response to PUB/MH II-101(a), Manitoba Hydro advises that inverted rates for Residential class customers are not under active consideration at this time.

Given that Manitoba Hydro has advanced evidence on the Cost of Service Study, which would support the proposal for the differentiation of rate changes to various customer classes, and the design of Time-of-Use Rates for General Service customers >30kV, Manitoba Hydro is of the view that the upcoming public review process and associated stakeholder conferences should be confined to those matters. Manitoba Hydro does not support GAC's proposal to review residential rate structures at this time, nor does it propose to expand its current proposal to include "Non-TOU General Service rate structures" in the upcoming public hearing process. Manitoba Hydro is prepared to consider stakeholder conferences on these matters once the current GRA, including the Cost of Service and TOU rate review is concluded.

ATTACHMENT A: COMPARISON OF ASL AND ELG SCENARIOS FOR A DECLINING ASSET POOL

Asset Cost and Retirement Assumptions

A $100,000 investment is made in a group of like assets with an average life of 5.5 years and a simple step-function survivor curve (i.e., $10,000 of gross plant retired each year). Retirements occur at the end of each year.

Annual Expense: ELG procedure for group depreciation

	Cost			Accumulated Depreciation			Annual Expense			
Year	Cost at Beginning of Year	Assets Retired	Cost at End of Year	Depreciation Taken	Depreciation Retired	Accumulated Depreciation at End of Year	Depreciation Rate	Depreciation Expense	(Gain) / Loss on Assets Retired	Total Expense
1	$ 100,000	$ (10,000)	$ 90,000	$ (29,290)	$ 10,000	$ (19,290)	29.3%	$ 29,290	$ -	$ 29,290
2	90,000	(10,000)	80,000	(19,290)	10,000	(28,579)	21.4%	19,290	-	19,290
3	80,000	(10,000)	70,000	(14,290)	10,000	(32,869)	17.9%	14,290	-	14,290
4	70,000	(10,000)	60,000	(10,956)	10,000	(33,825)	15.7%	10,956	-	10,956
5	60,000	(10,000)	50,000	(8,456)	10,000	(32,282)	14.1%	8,456	-	8,456
6	50,000	(10,000)	40,000	(6,456)	10,000	(28,738)	12.9%	6,456	-	6,456
7	40,000	(10,000)	30,000	(4,790)	10,000	(23,528)	12.0%	4,790	-	4,790
8	30,000	(10,000)	20,000	(3,361)	10,000	(16,889)	11.2%	3,361	-	3,361
9	20,000	(10,000)	10,000	(2,111)	10,000	(9,000)	10.6%	2,111	-	2,111
10	10,000	(10,000)	-	(1,000)	10,000	-	10.0%	1,000	-	1,000
		$ (100,000)		$ (100,000)	$ 100,000			$ 100,000	$ -	$ 100,000

Depreciation Rate:

Year 1: **[**($10,000 / 10 years) + ($10,000 / 9 years) + … + ($10,000 / 1 year)**]** / $100,000

Year 2: **[**($10,000 / 10 years) + ($10,000 / 9 years) + … + ($10,000 / 2 year)**]** / $90,000

…

Year 10: ($10,000 / 10 years) / $10,000

Asset Retirement Calculations: Gains and losses on disposition of assets are recognized immediately. The amount of accumulated depreciation retired is calculated as: Cost of item(s) retired x number of years depreciated / expected life of item(s) retired.

Year 1: $10,000 x 1 year / 1 year

Year 2: $10,000 x 2 years / 2 years

…

<u>Annual Expense: ASL procedure for group depreciation with recognition of gains and losses</u>

	Cost			Accumulated Depreciation			Annual Expense			
Year	Cost at Beginning of Year	Assets Retired	Cost at End of Year	Depreciation Taken	Depreciation Retired	Accumulated Depreciation at End of Year	Depreciation Rate	Depreciation Expense	(Gain) / Loss on Assets Retired	Total Expense
1	$ 100,000	$ (10,000)	$ 90,000	$ (18,182)	$ 1,818	$ (16,364)	18.2%	$ 18,182	$ 8,182	$ 26,364
2	90,000	(10,000)	80,000	(16,364)	3,636	(29,091)	18.2%	16,364	6,364	22,727
3	80,000	(10,000)	70,000	(14,545)	5,455	(38,182)	18.2%	14,545	4,545	19,091
4	70,000	(10,000)	60,000	(12,727)	7,273	(43,636)	18.2%	12,727	2,727	15,455
5	60,000	(10,000)	50,000	(10,909)	9,091	(45,455)	18.2%	10,909	909	11,818
6	50,000	(10,000)	40,000	(9,091)	10,909	(43,636)	18.2%	9,091	(909)	8,182
7	40,000	(10,000)	30,000	(7,273)	12,727	(38,182)	18.2%	7,273	(2,727)	4,545
8	30,000	(10,000)	20,000	(5,455)	14,545	(29,091)	18.2%	5,455	(4,545)	909
9	20,000	(10,000)	10,000	(3,636)	16,364	(16,364)	18.2%	3,636	(6,364)	(2,727)
10	10,000	(10,000)	-	(1,818)	18,182	-	18.2%	1,818	(8,182)	(6,364)
		$ (100,000)		$ (100,000)	$ 100,000			$ 100,000	$ -	$ 100,000

Depreciation Rate: (1 / Average Service Life) = 1/ 5.5 years = 18.181 %

Asset Retirement Calculations: Gains and losses on disposition of assets are recognized immediately. The amount of accumulated depreciation retired is calculated as: Cost of item(s) retired x depreciation rate x number of years depreciated.

Year 1: $10,000 x 18.181% x 1 year

Year 2: $$10,000 x 18.181% x 2 years

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<u>Annual Expense: ASL Procedure for group depreciation with deferral of gains and losses, and with depreciation studies every three years</u>

	Cost			Accumulated Depreciation			Annual Expense				
							Depreciation Rate				
Year	Cost at Beginning of Year	Assets Retired	Cost at End of Year	Depreciation Taken	Depreciation Retired	Accumulated Depreciation at End of Year	Base	True-up	Depreciation Expense	(Gain) / Loss on Assets Retired	Total Expense
1	$ 100,000	$ (10,000)	$ 90,000	$ (18,182)	$ 10,000	$ (8,182)	18.2%	0.0%	$ 18,182	$ -	$ 18,182
2	90,000	(10,000)	80,000	(16,364)	10,000	(14,545)	18.2%	0.0%	16,364	-	16,364
3	80,000	(10,000)	70,000	(14,545)	10,000	(19,091)	18.2%	0.0%	14,545	-	14,545
4	70,000	(10,000)	60,000	(20,364)	10,000	(29,455)	18.2%	10.9%	20,364	-	20,364
5	60,000	(10,000)	50,000	(17,455)	10,000	(36,909)	18.2%	10.9%	17,455	-	17,455
6	50,000	(10,000)	40,000	(14,545)	10,000	(41,455)	18.2%	10.9%	14,545	-	14,545
7	40,000	(10,000)	30,000	(9,455)	10,000	(40,909)	18.2%	5.5%	9,455	-	9,455
8	30,000	(10,000)	20,000	(7,091)	10,000	(38,000)	18.2%	5.5%	7,091	-	7,091
9	20,000	(10,000)	10,000	(4,727)	10,000	(32,727)	18.2%	5.5%	4,727	-	4,727
10	10,000	(10,000)	-	14,545	18,182	-	18.2%	-163.6%	(14,545)	(8,182)	(22,727)
		$ (100,000)		$ (108,182)	$ 108,182				$ 108,182	$ (8,182)	$ 100,000

Base Depreciation Rate: (1 / Average Service Life) = 1/ 5.5 years = 18.181 %

True-Up Depreciation Rate:

Year 4 – 6 True-up (Based on balances at end of Year 3):

Expected accumulated Depreciation = Surviving assets x age / average service life = $70,000 x 3 / 5.5 = $ 38,182

Accumulated depreciation variance = $38,182 - $19,091 = $19,091 shortfall

Average Expected Remaining Life = Average service life – age = 5.5 – 3 = 2.5 years

Required annual adjustment to depreciation expense = variance / average remaining life = $19,091 / 2.5 years = $7,636

True-up Depreciation Rate = annual adjustment / total depreciable cost = $7,636 / $70,000 = **10.9%**

Year 7 – 9 True-up (Based on balances at end of Year 6):

Expected accumulated Depreciation = Surviving assets x age / average service life = $40,000 x 6 / 5.5 = $ 43,636

Accumulated depreciation variance = $43,636 - $41,455 = $2,182 shortfall

Average Expected Remaining Life = is assumed to be 1 year as the actual age of the asset exceeds the average life

Required annual adjustment to depreciation expense = variance / average remaining life = $2,182 / 1 year = $2,182

True-up Depreciation Rate = annual adjustment / total depreciable cost = $(2,182) / $40,000 = **5.5%**

Year 10 True-up (Based on balances at end of Year 9):

Expected accumulated Depreciation = Surviving assets x age / average service life = $10,000 x 9 / 5.5 = $ 16,364

Accumulated depreciation variance = $16,364 - $32,727 = $(16,364), an over-accrual

Average Expected Remaining Life = is assumed to be 1 year as the actual age of the asset exceeds the average life

Required annual adjustment to depreciation expense = variance / average remaining life = $(16,364) / 1 years = $16,364

True-up Depreciation Rate = annual adjustment / total depreciable cost = $(16,364) / $10,000 = **-163.6%**

Asset Retirement Calculations: As all gains and losses on disposition of assets are deferred until the last items are retired, an amount equal to cost is removed from accumulated depreciation with each interim retirement. All remaining accumulated depreciation is retired in year 10, generating a gain on the final disposition for the asset group.

ATTACHMENT B: COMPARISON OF ASL AND ELG SCENARIOS FOR AN ASSET POOL WITH A CONSTANT LEVEL OF INVESTMENT

In this attachment, four scenarios are provided to illustrate showing the different impact in the flow of expenses to the income statement that would result from the use of the Average Service Life (ASL) procedure for group depreciation with differing implementation patterns, versus the Equal Life Group (ELG) procedure for group depreciation.

Asset Cost and Retirement Assumptions

An identical asset pool is considered in each of the following four scenarios. For Simplicity, the effects of inflation are ignored. The asset pool consists of:

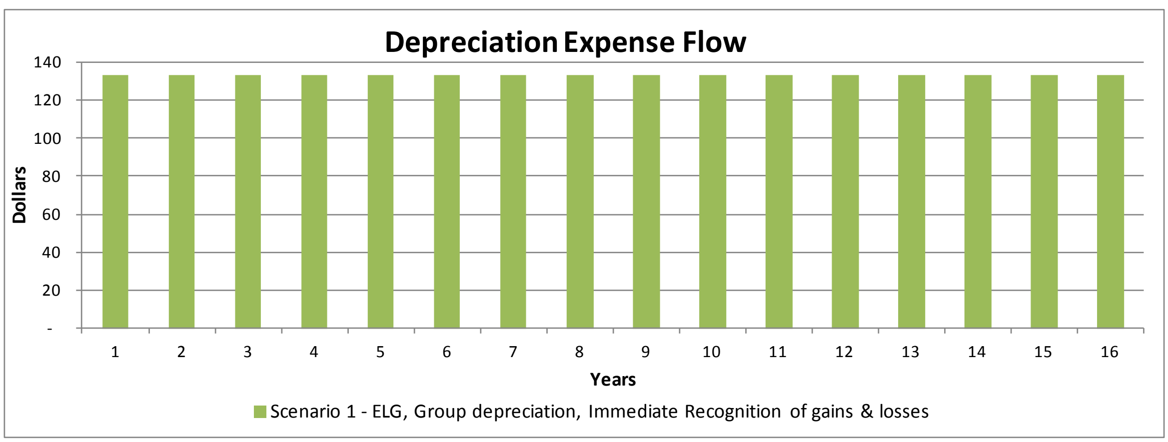
- Five units each costing $100, which have a service life of five years, and which will be replaced immediately on retirement with five more units.
- Five units each costing $100, which have an expected service life of fifteen years, and which will be replaced immediately on retirement.
- All asset retirements and additions occur at the end of the year expected.
- At any point in time:
  - The assets have a combined cost of $1,000;
  - One half of the asset base is expected to last five years and one half of the asset base is expected to last fifteen years; and,
  - The weighted average expected service life of the combined asset group is ten years.

Asset Cost Continuity Schedule

	Asset Sub-Group 1 (5 year life)				Asset Sub-Group 2 (15 year life)				Combined Asset Group			
Year	Cost at Beginning of Year	Assets Retired	Assets Added	Cost at End of Year	Cost at Beginning of Year	Assets Retired	Assets Added	Cost at End of Year	Cost at Beginning of Year	Assets Retired	Assets Added	Cost at End of Year
0	$ -		$ 500	$ 500	$ -		$ 500	$ 500	$ -		$1,000	$1,000
1	500			500	500			500	1,000			1,000
2	500			500	500			500	1,000			1,000
3	500			500	500			500	1,000			1,000
4	500			500	500			500	1,000			1,000
5	500	(500)	500	500	500			500	1,000	(500)	500	1,000
6	500			500	500			500	1,000			1,000
7	500			500	500			500	1,000			1,000
8	500			500	500			500	1,000			1,000
9	500			500	500			500	1,000			1,000
10	500	(500)	500	500	500			500	1,000	(500)	500	1,000
11	500			500	500			500	1,000			1,000
12	500			500	500			500	1,000			1,000
13	500			500	500			500	1,000			1,000
14	500			500	500			500	1,000			1,000
15	500	(500)	500	500	500	(500)	500	500	1,000	(1,000)	1,000	1,000
16	500			500	500			500	1,000			1,000
		$(1,500)	$2,000			$(500)	$1,000			$(2,000)	$3,000	

<u>Scenario 1: ELG; Group depreciation; Immediate recognition of gains and losses.</u>

This scenario is comparable to the ELG implementation which has been proposed for use by Manitoba Hydro for IFRS and regulatory reporting purposes.



Scenario 1 - Annual Expense & Accumulated Depreciation Continuity Schedule

		Depreciation				Expenses Recognized				Accumulated Depreciation
Year	Cost	Base Rate	Base Expense	True-Up Rate	True-Up Expense	Total Depreciation	(Gain) / Loss on Asset	Total Annual	Depreciation Retired	at End of Year
1	$ 1,000	13.3%	$ 133		$ -	$ 133	$ -	$ 133	$ -	$ (133)
2	1,000	13.3%	133		-	133	-	133	-	(267)
3	1,000	13.3%	133		-	133	-	133	-	(400)
4	1,000	13.3%	133		-	133	-	133	-	(533)
5	1,000	13.3%	133		-	133	-	133	500	(167)
6	1,000	13.3%	133	0.0%	-	133	-	133	-	(300)
7	1,000	13.3%	133	0.0%	-	133	-	133	-	(433)
8	1,000	13.3%	133	0.0%	-	133	-	133	-	(567)
9	1,000	13.3%	133	0.0%	-	133	-	133	-	(700)
10	1,000	13.3%	133	0.0%	-	133	-	133	500	(333)
11	1,000	13.3%	133	0.0%	-	133	-	133	-	(467)
12	1,000	13.3%	133	0.0%	-	133	-	133	-	(600)
13	1,000	13.3%	133	0.0%	-	133	-	133	-	(733)
14	1,000	13.3%	133	0.0%	-	133	-	133	-	(867)
15	1,000	13.3%	133	0.0%	-	133	-	133	1,000	-
16	1,000	13.3%	133	0.0%	-	133	-	133	-	(133)
			$ 2,133		$ -	$ 2,133	$ -	$ 2,133	$ 2,000	

Scenario 1 Calculations:

Base Depreciation Rate: [($500 / 5 years) + ($500 / 15 years)] / $1000

Asset Retirement Calculations: Gains and losses on disposition of assets are recognized immediately in this scenario. Accumulated depreciation retired is calculated as Cost of item(s) retired x number of years depreciated / expected life of items retired

- Year 5: $500 x 5 years / 5 years = $500 accumulated depreciation, $0 loss.
- Year 10: $500 x 5 years / 5 years = $500 accumulated depreciation, $0 loss.
- Year 15: [Sub-Group 1: $500 x 5 years / 5 years = $500 accumulated depreciation, $0 loss] plus [Sub-Group 2: $500 x 15 years / 15 years = $500 accumulated depreciation, $0 loss]

Depreciation Adjustment – True-up Rates: There is no need for a true-up rate in this scenario to correct depreciation expense, as the accumulated depreciation balance at the end of each 5 year interval matches the expected accumulated balance for the underlying assets:

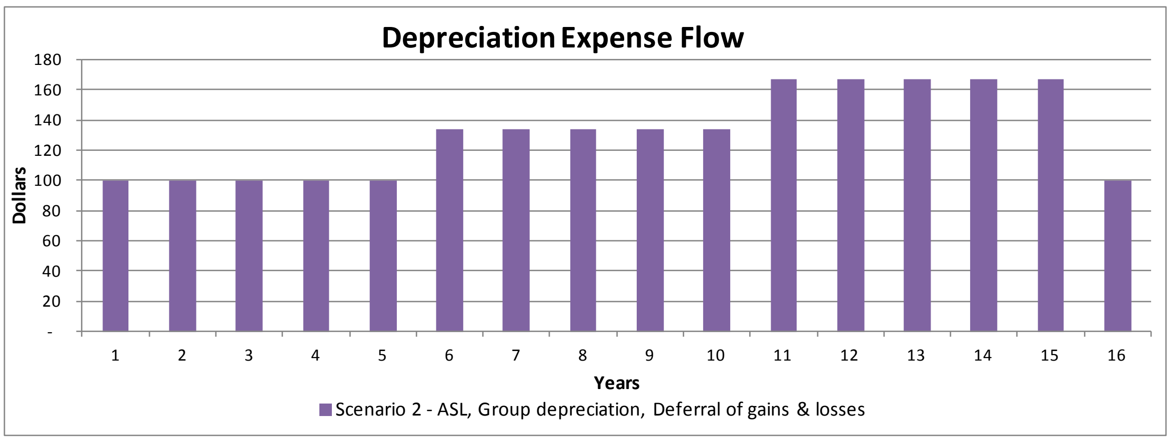
- Year 5: Sub Group 1: $500 x (0 / 5) years + Sub-Group 2 $500 x (5 / 15) years = $167
- Year 10: Sub Group 1: $500 x (0 / 5) years + Sub-Group 2 $500 x (10 / 15) years = $333
- Year 15: Sub Group 1: $500 x (0 / 5) years + Sub-Group 2 $500 x (0 / 15) years = $0

Suitability for Use in Rate Setting: This scenario is acceptable for rate setting as the equal expense pattern matches the assets available for use in each year.

IFRS Compliance: Scenario 1 is IFRS compliant as the pattern of depreciation expense matches the expected life for all assets, and gains and/or losses are realized immediately in income.

Scenario 2: ASL; Group depreciation; Deferral of gains and losses

This scenario is comparable to the ASL implementation which is currently used by Manitoba Hydro for Canadian GAAP and regulatory reporting purposes.



Gains or losses on disposition of assets are deferred, and are recovered over the remaining life of the assets in the group through the use of a "true-up" depreciation adjustment which is determined at each depreciation study.

The scenario assumes a five year interval between depreciation studies, which is consistent with the approach taken by Manitoba Hydro.

Scenario 2 - Annual Expense & Accumulated Depreciation Continuity Schedule

		Depreciation				Expenses Recognized				
Year	Cost	Base Rate	Base Expense	True-Up Rate	True-Up Expense	Total Depreciation Expense	(Gain) / Loss on Asset Disposal	Total Annual Expense	Depreciation Retired	Accumulated Depreciation at End of Year
1	$ 1,000	10.0%	$ 100		$ -	$ 100	$ -	$ 100	$ -	$ (100)
2	1,000	10.0%	100		-	100	-	100	-	(200)
3	1,000	10.0%	100		-	100	-	100	-	(300)
4	1,000	10.0%	100		-	100	-	100	-	(400)
5	1,000	10.0%	100		-	100	-	100	500	-
6	1,000	10.0%	100	3.3% **A**	33	133	-	133	-	(133)
7	1,000	10.0%	100	3.3%	33	133	-	133	-	(267)
8	1,000	10.0%	100	3.3%	33	133	-	133	-	(400)
9	1,000	10.0%	100	3.3%	33	133	-	133	-	(533)
10	1,000	10.0%	100	3.3%	33	133	-	133	500	(167)
11	1,000	10.0%	100	6.7% **B**	67	167	-	167	-	(333)
12	1,000	10.0%	100	6.7%	67	167	-	167	-	(500)
13	1,000	10.0%	100	6.7%	67	167	-	167	-	(667)
14	1,000	10.0%	100	6.7%	67	167	-	167	-	(833)
15	1,000	10.0%	100	6.7%	67	167	-	167	1,000	-
16	1,000	10.0%	100	0.0% **C**	-	100	-	100	-	(100)
			$ 1,600		$ 500	$ 2,100	$ -	$ 2,100	$ 2,000	

Scenario 2 Calculations:

Base Depreciation Rate: (1 / Average Service Life) = (1 / 10) = 10%

Asset Retirement Calculations: As the gains or losses on disposition of assets are deferred in this scenario, the accounting entry posted is to reduce both cost and accumulated depreciation by the full original cost of the assets to be retired, in this scenario, $500 at the end of years 5 and 10, and $1,000 at the end of year 15.

Depreciation Adjustment – True-up Rates:

A) Scenario 2 - True-Up Rate Calculation - End of Year 5:

Age	Cost	Average Expected Life (Years)	Age as a % of Expected Life	Expected Remaining Life (Years)	Expected Accumulated Depreciation	
0	$ 500	10	0.000	10	$ 0	
5	500	10	0.500	5	(250)	
10	-	10	1.000	0	-	
	$ 1,000 a				($ 250)	b
Actual Accumulated Depreciation					-	c
Accumulated Depreciation Variance				(b - c)	($ 250)	d
Weighted Average Remaining Life: (sum of % total cost x remaining life for each age)					7.5	e
Annual depreciation true-up required:				(d / e)	($ 33)	f
Depreciation True-up Rate:				(f / a)	**3.3%**	

B) Scenario 2 - True-Up Rate Calculation - End of Year 10:

Age	Cost	Expected Life (Years)	Age as a % of Expected Life	Expected Remaining Life (Years)	Expected Accumulated Depreciation	
0	$ 500	10	0.000	10	$ 0	
5	-	10	0.500	5	-	
10	500	10	1.000	0	(500)	
	$ 1,000 a				($ 500)	b
Actual Accumulated Depreciation					(167)	c
Accumulated Depreciation Variance				(b - c)	($ 333)	d
Weighted Average Remaining Life: (sum of % total cost x remaining life for each age)					5	e
Annual depreciation true-up required:				(d / e)	($ 67)	f
Depreciation True-up Rate:				(f / a)	**6.7%**	

C) Scenario 2 - True-Up Rate Calculation - End of Year 15:

Age	Cost		Expected Life (Years)	Age as a % of Expected Life	Expected Remaining Life (Years)		Expected Accumulated Depreciation	
0	$ 1,000		10	0.000	10		$ 0	
5	-		10	0.500	5		-	
0	-		10	0.000	10		-	
	$ 1,000	a					$ 0	b
Actual Accumulated Depreciation							-	c
Accumulated Depreciation Variance						(b - c)	$ 0	d

As there is no Accumulated Depreciation Variance at the end of year 15, the true-up rate = **0%**

Suitability for Use in Rate Setting: From a rate setting perspective, this scenario is not ideal, as it produces a shifting pattern of depreciation expense, where the costs for an unchanging asset base increase over time until the longer lived assets in the group are retired.

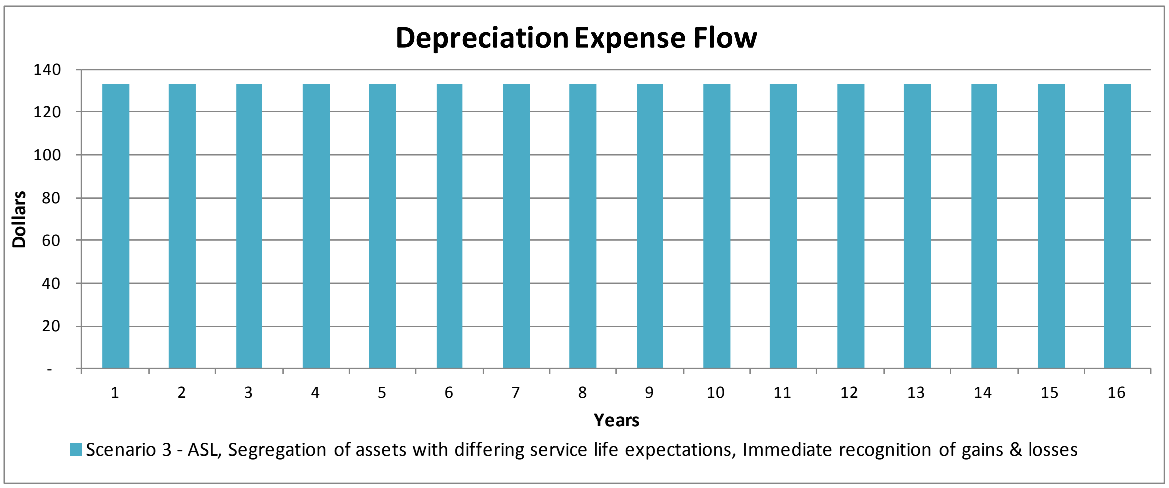
- In the example, ratepayers in years 6 – 10 are appropriately charged 1/3 of the total costs, while ratepayers in years 1 – 5 would benefit from lower depreciation rates, and ratepayers in years 10 – 15 would be burdened by higher depreciation rates.

IFRS Compliance: In Scenario 2, the retirement entry at the end of year 5 fully extinguishes the accumulated depreciation balance of the account, leaving no remaining balance to be associated with the longer lived items in the group. Scenario 2 fails to meet IFRS requirements in two areas:

- Treatment of gains and losses: IFRS specifically states that gains and losses on the disposition of assets are to be recognized as incurred.
- Pattern of depreciation expense: Following the retirement at the end of year 5, the group still contains 5 units which have an individual expected life of 15 years, and which has been depreciating for 1/3 of their expected lives, but the accumulated depreciation balance does not reflect this. As such, this method does not generate a depreciation expense pattern which is true to the useful lives of the parts included in the group.

Scenario 3: ASL; Segregation of assets with differing service life expectations; Immediate recognition of gains and losses.

This scenario is comparable to Manitoba Hydro's understanding of the ASL implementation in use by BC Hydro, Newfoundland and Labrador Hydro, SaskPower and Hydro Quebec, whereby a significantly greater level of componentization is used in combination with individual asset depreciation and with immediate recognition of gains & losses on retirement of assets.



In this scenario, the sub-groups of assets with different expected service lives are separately depreciated, and gains or losses are taken into income in the year the assets are retired.

Scenario 3 - Annual Expense & Accumulated Depreciation Continuity Schedule

	Asset Group 1 (5 year life)						
		Depreciation		(Gain) / Loss on Asset Disposal			Accumulated Depreciation After Retirement
Year	Cost	Rate	Expense		Annual Expense	Depreciation Retired	
1	$ 500	20.0%	$ 100		$ 100		$ (100)
2	500	20.0%	100		100		(200)
3	500	20.0%	100		100		(300)
4	500	20.0%	100		100		(400)
5	500	20.0%	100	-	100	500	-
6	500	20.0%	100		100		(100)
7	500	20.0%	100		100		(200)
8	500	20.0%	100		100		(300)
9	500	20.0%	100		100		(400)
10	500	20.0%	100	-	100	500	-
11	500	20.0%	100		100		(100)
12	500	20.0%	100		100		(200)
13	500	20.0%	100		100		(300)
14	500	20.0%	100		100		(400)
15	500	20.0%	100	-	100	500	-
16	500	20.0%	100		100		(100)
			$ 1,600	-	$1,600	$ 1,500	

Scenario 3 - Annual Expense & Accumulated Depreciation Continuity Schedule

	Asset Group 2 (15 year life)							Total Annual Expense		
		Depreciation		(Gain) / Loss on Asset Disposal			Accumulated Depreciation After Retirement		(Gain) / Loss on Asset Disposal	
Year	Cost	Rate	Expense		Annual Expense	Depreciation Retired		Depreciation Expense		Total Expense
1	$ 500	6.7%	$ 33		$ 33		$ (33)	$ 133	$ -	$ 133
2	500	6.7%	33		33		(67)	133	-	133
3	500	6.7%	33		33		(100)	133	-	133
4	500	6.7%	33		33		(133)	133	-	133
5	500	6.7%	33		33		(167)	133	-	133
6	500	6.7%	33		33		(200)	133	-	133
7	500	6.7%	33		33		(233)	133	-	133
8	500	6.7%	33		33		(267)	133	-	133
9	500	6.7%	33		33		(300)	133	-	133
10	500	6.7%	33		33		(333)	133	-	133
11	500	6.7%	33		33		(367)	133	-	133
12	500	6.7%	33		33		(400)	133	-	133
13	500	6.7%	33		33		(433)	133	-	133
14	500	6.7%	33		33		(467)	133	-	133
15	500	6.7%	33	-	33	500	-	133	-	133
16	500	6.7%	33		33		(33)	133	-	133
			$ 533	-	$ 533	$ 500		$ 2,133	$ -	$2,133

Scenario 3 Calculations:

Base Depreciation Rate:

- Asset Group 1: (1 / Average Service Life) = (1 / 5) = 20.0%
- Asset Group 2: (1 / Average Service Life) = (1 / 15) = 6.7%

Depreciation Adjustment – True-up Rates: There are no need for depreciation true-up rates in this scenario, as there is no variation in age, in the expected service life, or in the realization of the service life of the assets within each of the independently depreciated asset groups.

Asset Retirement Calculations: Gains and losses on disposition of assets are recognized immediately in this scenario. Accumulated depreciation retired is calculated as Cost of item(s) retired x depreciation rate in use x number of years depreciated:

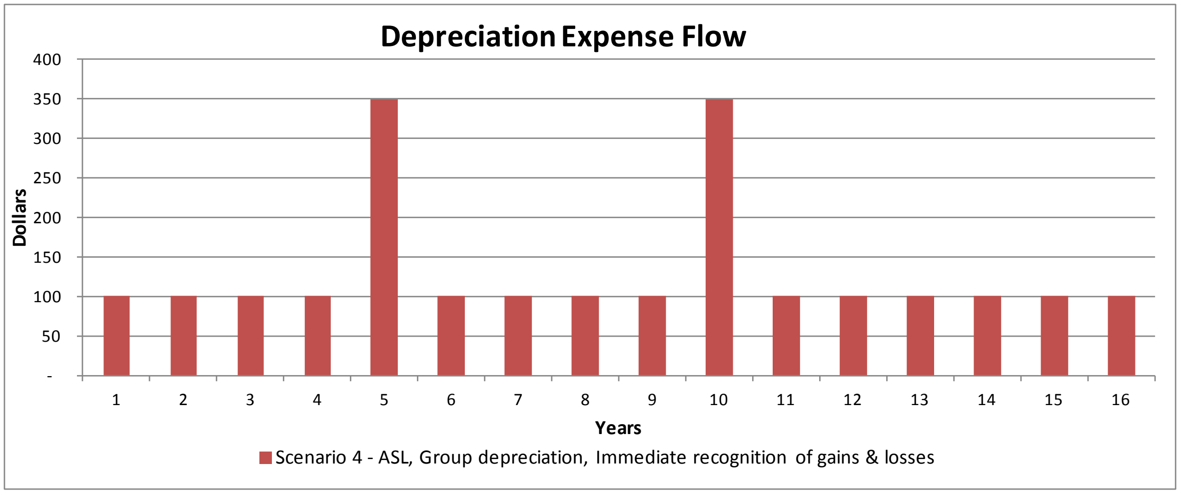
- Asset Group 1:
  - Year 5: $500 x 20% x 5 years = $500 accumulated depreciation, $0 loss.
  - Year 10: $500 x 20% x 5 years = $500 accumulated depreciation, $0 loss.
  - Year 15: $500 x 20% x 5 years = $500 accumulated depreciation, $0 loss.
- Asset Group 2:
  - Year 15: $500 x 6.7% x 15 years = $500 accumulated depreciation, $0 loss.

Suitability for Use in Rate Setting: This scenario is acceptable for rate setting as the equal expense pattern matches the assets available for use in each year.

IFRS Compliance: Scenario 3 is IFRS compliant as the pattern of depreciation expense matches the expected life for all assets, and gains and/or losses are realized immediately in income.

<u>Scenario 4: ASL; Group Depreciation; Immediate recognition of gains and losses</u>

This scenario reflects the impact on net expense of using ASL with group accounting and immediate recognition gains and losses on disposal of assets.



Gains or losses on disposition of assets are taken into income in the year the assets are retired.

The scenario assumes a five year interval between depreciation studies, which is consistent with the approach taken by Manitoba Hydro.

Scenario 4 - Annual Expense & Accumulated Depreciation Continuity Schedule

		Depreciation				Expenses Recognized				
Year	Cost	Base Rate	Base Expense	True-Up Rate	True-Up Expense	Total Depreciation Expense	(Gain) / Loss on Asset Disposal	Total Annual Expense	Depreciation Retired	Accumulated Depreciation at End of Year
1	$ 1,000	10.0%	$ 100		$ -	$ 100	$ -	$ 100	$ -	$ (100)
2	1,000	10.0%	100		-	100	-	100	-	(200)
3	1,000	10.0%	100		-	100	-	100	-	(300)
4	1,000	10.0%	100		-	100	-	100	-	(400)
5	1,000	10.0%	100		-	100	250	350	250	(250)
6	1,000	10.0%	100	0.0%	-	100	-	100	-	(350)
7	1,000	10.0%	100	0.0%	-	100	-	100	-	(450)
8	1,000	10.0%	100	0.0%	-	100	-	100	-	(550)
9	1,000	10.0%	100	0.0%	-	100	-	100	-	(650)
10	1,000	10.0%	100	0.0%	-	100	250	350	250	(500)
11	1,000	10.0%	100	0.0%	-	100	-	100	-	(600)
12	1,000	10.0%	100	0.0%	-	100	-	100	-	(700)
13	1,000	10.0%	100	0.0%	-	100	-	100	-	(800)
14	1,000	10.0%	100	0.0%	-	100	-	100	-	(900)
15	1,000	10.0%	100	0.0%	-	100	-	100	1,000	-
16	1,000	10.0%	100	0.0%	-	100	-	100	-	(100)
			$ 1,600		$ -	$ 1,600	$ 500	$ 2,100	$ 1,500	

Scenario 4 Calculations:

Base Depreciation Rate: (1 / Average Service Life) = (1 / 10) = 10%

Asset Retirement Calculations: Gains and losses on disposition of assets are recognized immediately in this scenario. Accumulated depreciation retired is calculated as Cost of item(s) retired x depreciation rate in use x number of years depreciated:

- Year 5: $500 x 10% x 5 years = $250 accumulated depreciation, $250 loss.
- Year 10: $500 x 10% x 5 years = $250 accumulated depreciation, $250 loss.
- Year 15: [Group 1: $500 x 10% x 5 years = $250 accumulated depreciation, $250 loss] plus [Group 2: $500 x 10% x 15 years] = $750 accumulated depreciation, $250 gain]

Depreciation Adjustment – True-up Rates: There is no need for a true-up rate in this scenario to correct depreciation expense, as the accumulated depreciation balance at the end of each 5 year interval matches the expected accumulated balance as calculated for Scenario 2:

- Year 5: $ (250)
- Year 10: $ (500)
- Year 15: $ 0

Suitability for Use in Rate Setting: From a rate setting perspective, this scenario is deficient for the following reasons:

- The pattern of expense recognition is very uneven, with large corrections required in years 5 and 10.
- Although there is an equal availability and use of assets in each year, the expense pattern does not reflect that, as higher expense recognition in years 1 – 10 as compared to years 11 – 15
    - Expense for years 1 – 5 equals $750
    - Expense in years 6 – 10 equals $750
    - Expense in years 11 – 15 equals $500

IFRS Compliance: In Scenario 4, a loss is realized on the retirement of assets with lives shorter than the average and a gain is realized on the retirement of assets with lives longer than the average. Scenario 4 fails to meet IFRS requirements as the pattern of depreciation expense is not true to the expected useful lives of the items included in the group, which is evident from the fact that none of the assets in this scenario are fully depreciated when retired. Those with a 5 year life are under-depreciated when retired and those with a 15 year life are over-depreciated.