Exhibit PUB #

Volume 2 – Board Counsel's Book of Documents

Manitoba Hydro 2012/13 and 2013/14 GRA

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MANITOBA THE PUBLIC UTILITIES BOARD ACT THE MANITOBA HYDRO ACT THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	Board Order 101/04 July 28, 2004

Before: G. Lane C.A., Chair
R. Mayer Q.C., Vice-Chair
L. Evans, Member

AN ORDER IN RESPECT OF AN APPLICATION BY MANITOBA HYDRO FOR INCREASED RATES WITH FURTHER DIRECTIVES AND REASONS TO FOLLOW

basis, implications could range from higher bills for some customers to impacts on commercial and industrial activities.

6.0 Board Findings

6.1 Revenue Requirement and General Rates

The Board accepts the CAC/MSOS comments with respect to arithmetical errors in MH's integrated financial forecast. Nonetheless, the Board accepts the overall forecast for net income for 2004/05 and 2005/06 provided by MH as being reasonable, having been based on macro assumptions. While the costs pointed out by CAC/MSOS may be over estimated, there may be offsetting items in the IFF. As well, the Board is of the view that there is a need for MH to rebuild retained earnings, particularly depressed as a result of the drought and required to meet on-going risks.

The Board has reasonable confidence in MH's efforts to project expenses. That being said, one of the goals of the hearing process is to best ensure that such confidence in the Corporation's forecasting is also shared by the Intervenors.

The Board finds that a more detailed examination of MH's cost experience and forecasts in future rate hearings would be in the public interest. The Corporation is engaged in a number of concurrent activities, projects and research initiatives, all requiring a substantial investment in personnel and consultants.

Cognizant of the necessity for the Corporation to meet its challenges effectively, managing the export activities being a prime example, the Board is reluctant, in fact unable on the record of this proceeding, to provide critical judgement on the appropriateness of the current and projected departmental and functional personnel complement and cost levels.

The Board acknowledges that it is not alone in its oversight of the Corporation, and that its jurisdiction is limited. Accordingly, the Board finds it necessary and reasonable to rely upon the Corporation's Board, the Government, and Crown Corporations Council with respect to administrative oversight of MH's operating and capital expenditures.

Nonetheless, noting the ongoing and substantial increases in MH's operating, maintenance and administration expenses, and observing the continuing material negative differential between the costs per customer between MH and BC Hydro (as reported during the hearing), a more detailed examination of costs at future rate hearings represents a reasonable objective.

Rate Increases

On an overall basis, the Board finds the financial impact of the drought on MH to have been extremely significant, and, combining this with other factors results in the requested rate increases being insufficient.

Additional revenue is immediately required to begin the rebuilding of MH's retained earnings, towards the broadly accepted debt to equity ratio target of 75:25. The Board will expect MH to maintain vigilance over its costs, so that the additional revenues contribute as they are intended to move towards achieving the debt to equity target more quickly than suggested in MH's 2003 Integrated Financial Forecast.

Accordingly, and after careful reflection and realizing the additional burden that will placed on the economy, the Board has determined to vary MH's rate increase requests.

MANITOBA	**Board Order 116/08**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**July 29, 2008**
Edited for format and typographical errors only August 25, 2008 Further amended September 4, 2008	

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair
Susan Proven, P.H.Ec., Member

AN ORDER SETTING OUT FURTHER DIRECTIONS, RATIONALE AND BACKGROUND FOR OR RELATED TO THE DECISIONS IN BOARD ORDER 90/08 WITH RESPECT TO AN APPLICATION BY MANITOBA HYDRO FOR INCREASED RATES AND FOR RELATED MATTERS

MKO also recommended that MH and the Board clearly distinguish MH's necessary and appropriate costs (expenditures and investments related to operations, mitigation and agreement obligations) from "charitable donations". MKO suggested that endowments funded by MH's net export revenues (intended to benefit "MH Affected Communities", such as for regional economic development, community infrastructure and the enhancement of fish and wildlife) should not be "charitable donations".

5.8 Board Findings

The Board remains concerned with the growth of OM&A expenses, particularly the level and growth of these expenditures prior to deferrals, capitalization and allocations to subsidiaries.

As stated in Order 101/04:

> "The Board will expect MH to maintain vigilance over its costs, so that the additional revenues [from PUB approved rate increases] contribute as they are intended to move towards achieving the debt to equity target more quickly than suggested in MH's 2003 Integrated Financial Forecast."

Expectations from past recommendations related to OM&A expenses have not been met. The Board expects MH to control OM&A expense levels to assist in meeting its financial targets. Further control of OM&A costs is vital given the planned major capital expansion, and in light of the fact that MH will not meet its debt to equity target over the current forecast period.

And, in this Order, the Board continues to be concerned with MH's "aggressive" capitalization and deferral policies with respect to OM&A expenses. While there is an argument for the practice, the net result is that costs now being incurred are not reflected in rates until years, in fact decades, later, meaning the current generation of ratepayers leave the results for the generations that will follow to meet.

The following concern, from Order 143/04, echoes past concerns raised by the Board with respect to the capitalization policies followed by MH. The Board then stated:

> "The Board is concerned with the range and level of costs being capitalized by MH. While the Board understands that many of the projects undertaken by MH are long-term in nature, both from a benefit and cost perspective, aggressively capitalizing costs and selecting long amortization periods increases the rate risks to future generations of electric customers. If the Board questions whether aggressive capitalization policies are prudent...... The Board does not dispute that MH's accounting is based on GAAP, only that GAAP also provides for a more conservative capitalization approach."

In Order 117/06 the Board further stated:

> "The Board is concerned with MH's present capitalization and notes MH's comment that net export revenue represents a form of "windfall" which cannot be guaranteed to continue at recent levels. Even though net export revenues have been significant over the past decade, progress towards the debt:equity target of 75:25 is slow."

The Board notes MH defends its level of OM&A expenditures on the basis of 'need' and has argued that it has successfully 'controlled OM&A cost per customer account'. The Board is of the view that this premise will remain not fully substantiated, given the enormous amount and percentage of total OM&A costs that have been and are forecast to be capitalized, at least until adequate peer benchmarking has been performed and the results reviewed.

As expressed in past Orders, for two decades MH's annual net income result has been assisted/increased by its deferral and capitalization process. If non – direct construction costs (an allocation of the salary of staff in contracts not involved in actual construction but more in planning in supporting roles) had been expensed

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in the period incurred, rather than capitalized or deferred, annual net income would have been considerably lower, and possibly negative in many years; OM&A cost per customer account would have been much higher; rate pressure would have been considerably greater than has been demonstrated to date; and retained earnings would be much lower.

As indicated, while there is an argument for MH's current approach (to expense costs in the current period and reflect them in current rates, when the costs relate to projects not expected to provide benefits until the future, would mean charging the current generation of MH's customers for costs that could arguably be met by future generations), MH's rate structure and rates, even including the increases directed and indicated in Order 90/08, is premised on past and future OM&A cost deferrals and capitalization. If the approach was to change (a distinct possibility with the upcoming adoption of IFRS), costs now capitalized in the current period would be expensed. This would, again as previously noted, result in current and future ratepayers being billed for costs reflective not only of current costs but also cost burdens avoided by past ratepayers as a result of the current process of deferral and capitalization.

The Board does not believe OM&A should be adjusted based on the corporate strategic plan target of $640 per customer as suggested by the Coalition. The Board is not convinced the benchmark is completely relevant, given the level of expense deferrals and capitalization impacting the current result. Once more stringent capitalization requirements are put in place with IFRS such a metric may have more value and use in the establishment of rate requirements.

To arbitrarily direct, as some interveners have suggested, that a significant amount of expense not be reflected in rates, as a way of sending a message to

MH that it is spending too much on OM&A, would be irresponsible given what the Board and the recent process has revealed.

This Board must rely on the public GRA process to provide opportunities to assess OM&A, and while the Board continues to express concern, there is nothing on the record sufficiently concrete to justify not accepting the costs in rates.

IFRS

The Board notes the coming adoption of IFRS is likely to have a material impact on MH's financial reporting and results. The Board further notes that AcSB has, in advance of IFRS, established a new reporting standard with respect to accounting for intangible assets [including goodwill, deferred charges and capitalized expenditures].

These new requirements are effective for fiscal years beginning on or after October 1, 2008 and could have an impact on MH's fiscal 2009 - 2010 accounts. However, the Board is aware that MH is looking to U.S. Federal Accounting Standards Board (FASB) accounting standards in support of its continuing its present accounting practices in the short term.

The Board's primary concern is not accounting for the short-term, but the long term, particularly with MH's massive capital expenditure plans.

The Board notes in The FASB Handbook section 71.34 (in part), Accounting for the Effects of Certain Types of Regulation, reads as follows:

> "The regulator's action provides reasonable assurance of the existence of an asset (paragraph 9). Accordingly, the regulated enterprise would capitalize the cost and amortize it over the period during which it will be allowed for rate-making purposes."

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MANITOBA

THE PUBLIC UTILITIES BOARD ACT

THE MANITOBA HYDRO ACT

THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT

Board Order 90/08

June 30, 2008

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair
Susan Proven, P.H.Ec., Member

ELECTRICITY RATES FOR MANITOBA HYDRO TO TAKE EFFECT JULY 1, 2008

complete these projects. Debt comes with costs, interest and annual principle payments, and, as well, is associated the risk of future increases in interest rates.

The Corporation's risks rise as its export opportunities, investments and debts increase. In the Board's view, this warrants a larger rate increase.

Fuel Switching

In addition, rate increases are further warranted to address an apparent disconnect that has developed between electricity rates and the prices of other energy commodities, this is of considerable concern to the Board, given MH's forecast methodology where export revenue rates are a relative function of natural gas pricing. The Board believes that there is a risk that this may have resulted in an overstatement of forecast export revenues. Power consumed domestically cannot be sold on the export market.

It is not necessarily in the public interest for short-term electricity rates to drastically lag natural gas pricing. Electric space heating could displace natural gas heating to a substantial degree if the current price disparity widens and continues. The result of fuel switching could see electric system peak capacity being challenged and the more frequent use of high price electricity imports.

OM&A Expenses

The Board shares some Intervener concerns as to the acceleration of MH's OM&A costs, which MH attributes the costs increases to labour shortages as well as increased needs for system maintenance, both factors cited to be beyond the direct control of the Utility.

However, the Board does not have enough information on whether the current and forecast OM&A are fully supported, since no formal and in-depth benchmarking has been undertaken.

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Lacking this information, the Board is not prepared to direct MH to reduce its OM&A expenditures. More will be provided on this topic in the forthcoming subsequent Order.

Adoption of International Financial Reporting Standards (IFRS)

The Board remains concerned with the continued high level of capitalization of OM&A expenditures. The Board anticipates that MH's current capitalization approach will change with the adoption of IFRS.

In the interim, the Board still (it has commented on this matter in previous orders) does not favour the continuation of a current practice that distorts the level of OM&A expenses. The change to IFRS will likely result in a higher level of OM&A expense impacting MH's profitability. The Board is currently not convinced that Regulatory accounting, i.e. the Board setting rates based on actual and forecast results prepared other than pursuant to GAAP, should be considered to counter the financial impacts of IFRS.

New Head Office

The Board also remains concerned on the cost consequences related to the new head office, noting that MH raised doubts at the hearing as to whether it would meet the level of savings required to fully offset the increase in costs related to the new building, now estimated at almost $19 million a year.

No evidence was presented that MH will find the necessary savings to offset this cost, however there may be long term benefits to be realized by the Utility that will be discovered and realized subsequently. The Board will require that these savings be demonstrated.

The Board will address this matter in more depth in the following Order.

MANITOBA	Board Order 99/11
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	July 29, 2011

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair

AN INTERIM ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR INCREASED 2010/11 AND 2011/12 RATES AND OTHER RELATED MATTERS

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revenue to avoid domestic ratepayers subsidizing export sales. A significant portion of the energy to be delivered under the export contracts will be based on spot and opportunity sale market rates, which may be depressed for some time due to reduced natural gas prices, that the result of seemingly abundant shale deposits which have and are expected to depress natural gas prices.

This in turn has and is presently expected to lower the incremental cost of generated electricity by American utilities in the MISO market, which may, as it has since 2008, depress the export prices MH realizes and may realize in the future. The Board has a serious concern as to current and potentially longer term MISO market conditions, which are outside the control of MH, and which may well have negative implications for domestic ratepayer rates.

If export revenues do not meet MH's currently forecast targets, and MH's currently planned major capital expenditures take place, MH will need to look towards domestic ratepayers to support much of the debt to be entered into to build the generation and transmission assets. Until, if possible, the risk of unacceptable future domestic rate increases can be reduced or eliminated (addressed to the Board's satisfaction), it seems quite possible that future rate increases, now forecast at 3.5% annually for ten years to be followed by 2% annually, may prove quite insufficient.

OM&A Expense

MH's forecast of its OM&A expenses assumes a productivity factor in the order of 0.5% to 1% annually (i.e. that costs will be lower by 1% in each future year due to ongoing productivity improvements – in the absence of achieving the annual productivity target, OM&A costs would, presumably, be 1% higher than MH's present forecast) in the setting of its business unit OM&A targets.

In Order 07/03, the Board stated:

> *"Corporate performance measures such as the operating and administration costs per customer or per kW.h targets are of great assistance in assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities."*

In Order 116/08 the Board stated:

> *"Although Hydro's operating and administrative expenses appear reasonable, the Board urges Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates of some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies. Corporate Performance measures such as operating and administration cost per customer or per kW.h targets are of great assistance in assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements of its operations as compared to other utilities."*

In that Order the Board directed:

> *"MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most current available data and including:*

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a) *Primary key drivers of OM&A in each operational division [Board preferences to allow for a comparison with a greater number of other utilities].*
b) *Comparable other Canadian Utility data for each of the drivers.*
c) *Key comparison indicators including staffing levels.*
d) *A comparison with and discussion of industry best practices.*
e) *Potential improvement areas."*

The Board expects to be apprised of the scope of the expected study, and its advancement (in advance of receipt and review of the study, it is difficult to complete an assessment of the prudency of MH's OM&A expenditures), and anticipates being provided the opportunity to provide direction.

The Board is convinced that domestic ratepayers will benefit from the developments of appropriate metrics to assess the reasonableness of the level of current and future OM&A expenses, in advance of, if not particularly because of, the proposed major capital expansion program (that program "driving" OM&A expenses).

To-date, the Board's past and present concerns on the ongoing annual escalation of MH's OM&A expenses have not been addressed. MH has not undertaken Board-directed benchmarking studies and has deferred such studies until 2013 (when IFRS is expected to be fully implemented).

In the meantime, OM&A expenses, particularly before the capitalization and deferral of a significant percentage of such expenses, have escalated well above inflation, in part due to MH's Preferred Development Plan. The Board remains concerned with the escalation of operating expense, of which a large portion is being deferred (to be borne by future ratepayers). Such deferral has muted the OM&A increases reflected in MH's annual accounts, its GRA rate requests and domestic rates.

OM&A costs have increased in part due to MH engaging hundreds of new employees involved, in one capacity or another, in implementing – ahead of regulatory approval - the Utility's development plans. OM&A period costs are being accumulated and that accumulated amount, which grows by the day, faces the risk that it may have to be "written off" if the development plans now proposed by MH are either significantly amended or rejected.

The Board questions the sincerity of MH's commitment to rein in costs, without action rate increases above inflation remain a probable outcome. As previously indicated, MH continues to capitalize and defer a significant portion of its annual operating costs.

While this practice has been accepted by MH's external auditor and, accordingly, may be considered to be within the guidelines of what now represents GAAP, Canadian accounting standards, and leaving aside that those guidelines and GAAP are in flux as the transition to IFRS continues, the practice allows MH to report higher annual net income results than it otherwise could (if more of the now deferred and capitalized expenses were treated as period costs and charged directly, in the year of incurrence, against the net income of that year).

Though these capitalized and/or deferred costs are presently not charged against net income in the year of incurrence and do not affect either MH's retained earnings and debt to equity ratio, they do not "go away", but are simply "transferred" to future years, where the costs will be charged by way of gradual amortization against the net income of those future years, affecting the revenue requirement and rates of those years.

These issues will be discussed further in the Board's subsequent Order.

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MANITOBA	**Board Order 5/12**
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	**January 17, 2012**

Before: Graham Lane CA, Chairman
Robert Mayer Q.C., Vice-Chair

A FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR INCREASED 2010/11 AND 2011/12 RATES AND OTHER RELATED MATTERS

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common assets to be capitalized. MH adjusted its overhead capitalization policy accordingly by reducing the amount of overhead capitalized to capital projects from 24% to 17% for 2010/11.

As a result of the accounting policy changes, MH reduced its total capitalized overhead by $5 million in 2008/09 and an additional $4 million in 2009/10. It also made a provision of $18 million in 2010/11 and $14 million in 2011/12, reflecting a reduction in the overhead rate.

9.6.0 O&A COST CONTROL PROCESS

MH's forecast provides for a productivity factor in the order of 0.5% to 1% annually in the setting of its business unit O&A targets. In response to the economic downturn, MH has put in place measures to constrain the increase of O&A, including a freeze on hiring of new positions (with the exception of line trades trainees), restrictions on out-of-province travel, rationalization of fleet vehicles, extension of service lives of computers and equipment and reduction of overtime costs where possible.

MH indicated that such measures were short-term and that cost containment measures would not compromise system safety and reliability. MH stated that such steps had resulted in reducing the year-over-year changes in O&A by 5% or $16 million in the first 10 months of the current fiscal year.

In Order 116/08 the Board stated:

> *"Although Hydro's operating and administrative expenses appear reasonable, the Board urges Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates that some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies. Corporate Performance measures such as operating and administration cost per customer or per kW.h targets are of great assistance in*

assessing the performance of Hydro's cost control initiatives compared to other utilities. The Board recommends Hydro aggressively pursue meeting its operating and administration costs per customer target while finding ways to increase productivity. The Board also encourages Hydro to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements of its operations as compared to other utilities."

In that Order the Board directed:

"MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most current available data and including:

a) Primary key drivers of OM&A in each operational division [Board preferences to allow for a comparison with a greater number of other utilities].

b) Comparable other Canadian Utility data for each of the drivers.

c) Key comparison indicators including staffing levels.

d) A comparison with and discussion of industry best practices.

e) Potential improvement areas."

The Board expects to be apprised of the scope of the study and advancement being undertaken, and will anticipate the opportunity to provide direction.

The Board is convinced that both the Province and ratepayers will benefit from the development of appropriate metrics to assess the reasonableness of the level of current and future OM&A expenses, in advance and particularly because of, the proposed major capital expansion program.

MH has deferred undertaking the Board-directed benchmarking study until after the implementation of IFRS in fiscal 2013.

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9.8.0 BOARD FINDINGS

The Board notes that the Corporation has shown some interest in undertaking cost-containment measures. However, such measures are far too modest and short-lived. MH's annual operating costs top $700 million, with targeted measures expected to deliver only $13 million of savings, or 2% of the total.

Given the corporation's current development plans, MH has seen material increases in staffing levels. MH has added over 900 employees since 2004, the majority engaged in one capacity or another in implementing the utility's development plan, well ahead of an NFAAT, regulatory approvals and firm export contract commitments. If the projects do not go ahead, MH faces the likelihood of having to expense expenditures currently deferred or capitalized.

The Board, in past Orders, has recommended that MH find ways to control the growth in operating expenses. The Board continues to believe that MH should look internally to find efficiencies and control the growth in operating expenses. To do otherwise increases the risks faced by ratepayers of paying higher rates than required.

The Board notes that during the last expansion phase in 1992, MH had an employee complement that peaked at 4,232 EFTs, with fewer than 900 dedicated to capital construction. Since then, staffing has ballooned to over 6,300 EFTs, with over 1,400 EFTs dedicated to construction-related efforts.

The impact of the large staff complement is muted by MH's capitalization policies. A significant portion of MH's operating expenses (in excess of 40%) are capitalized each and every year, masking the impact of the significant staffing levels at MH. There remains a risk that if the projects do not proceed or become economically not profitable, a significant amount of capital costs, now well in excess of $400 million will have to be written off.

It is also vitally important that MH undertake a benchmarking of its operations against peers with the goal to control the growth in operating expenses and foster practices, which improve efficiencies.

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Exhibit # MH-124
Transcript Page #_____

Manitoba Hydro Undertaking #123

Please file any directives issued by the President with respect to cost constraint measures from 2009.

Please see attached memos dated 2009 03 19 and 2009 05 01.

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MANITOBA HYDRO
INTEROFFICE MEMORANDUM

FROM R.B. Brennan
President and Chief Executive Officer

TO Vice-Presidents
Division Managers

DATE 2009 03 19

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SUBJECT **OPERATING, MAINTENANCE & ADMINISTRATION (OM&A) EXPENSE**

For some time now, I have been concerned about the substantial increases to Manitoba Hydro's Operating, Maintenance & Administrative (OM&A) expense. For the 11-month period ended February 28, 2009, OM&A expense has increased by over 8% at the Corporate level with even greater year-over-year increases in some Divisions. Increases in this order of magnitude are especially troublesome during these difficult economic times for industry, our customers, and other stakeholders.

I appreciate that Manitoba Hydro is facing increasing cost pressures due to more stringent environmental and business regulation, an aging infrastructure requiring higher maintenance, increased emphasis on employee safety and system reliability, and higher numbers of trainees being hired to meet our succession planning requirements. Nevertheless, all these factors were considered when Operating Budgets were approved in the fall of 2008. It is not acceptable for Operating Budgets to be over-expended to the extent we are seeing in fiscal year 2008/09.

As we will soon be embarking on a new fiscal year, all senior management should be aware that each Division will be expected to manage within their approved 2009/10 Operating Budget. Should an unforeseen event occur, specific approval of Executive Committee will be required to incur costs not included in approved budgets. Consequences of unapproved overspending in 2009/10 will include imposed restrictions on discretionary expenditures.

I am requesting that each Vice-President meet with their respective Division Managers to confirm Operating Budget forecasts for 2009/10 (within currently approved Business Unit budgets). The updated budgets should reflect the new organization structure. Following the Divisional meetings, I will meet with each Vice-President to reaffirm their approved Budget for 2009/10.

Thank you for your cooperation.

Bob

RBB/gt

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MANITOBA HYDRO

INTEROFFICE MEMORANDUM

FROM R.B. Brennan
President and Chief Executive Officer

TO See Below

DATE 2009 05 01

FILE

SUBJECT **RESTRICTIONS ON OPERATING & ADMINISTRATIVE EXPENSES**

In my memo to you dated March 19, 2009, I conveyed my concerns regarding the substantial increases being experienced in Operating, Maintenance & Administration (OM&A) expense. A schedule summarizing increases in OM&A over the past four years is attached for your reference. Since my March 19 memo, the economic situation in Canada and the United States continues to deteriorate and it is now clear that there will be negative impacts on Manitoba Hydro's domestic and export revenues in 2009/10. In recognition of the current economic situation, the following restrictions on operating expenses are being implemented effective immediately:

a) Out-of-province travel will be limited to essential travel only. Management discretion will be used to determine what travel is considered to be "essential," but I am requesting that every request that is advanced for approval be fully justified and that the consequences of travel not being approved be provided. Until further notice, all requests for out-of-province travel will require my approval. Please be certain that only essential travel requests are advanced for my approval. (This will not affect travel bookings and commitments that have been made at this date.)

b) Costs for promotion, awards, sponsorships and miscellaneous office expense will be curtailed to the absolute minimum level necessary.

Other restrictions on discretionary expenditures and hiring may be necessary as we determine the full impacts of the economic recession. Any such additional restrictions, however, will not be in areas that could compromise public and employee safety or the integrity of Manitoba Hydro's energy supply and delivery system.

Thank you for your cooperation during these difficult economic times.

Bob

RBB/gt
Att.

SAME MEMORANDUM TO:

K.R.F. Adams	G.W. Rose	T.E. Tymofichuk
E.R. Kristjanson	A.M. Snyder	V.A. Warden
G.B. Reed	K.M. Tennenhouse	C.E. Wray

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BUSINESS UNITS

OPERATING, MAINTENANCE & ADMINISTRATIVE (OM&A)
for the years ended March 31

(in millions of $)

	2006	% Incr. (decr.)	2007	% Incr. (decr.)	2008	% Incr. (decr.)	Preliminary 2009	% Incr. (decr.)
President & CEO	$ 17.0	7.6%	$ 18.1	6.5%	$ 17.4	(3.9%)	$ 18.5	6.1%
Corp. Relations	10.0	28.2%	10.2	2.0%	10.3	1.0%	10.5	2.0%
Finance & Admin.	88.2	1.8%	92.5	4.8%	90.5	(2.2%)	94.2	4.1%
Power Supply	117.4	3.3%	123.6	5.3%	127.8	3.4%	142.4	11.4%
T&D	104.8	(0.2%)	109.6	4.6%	112.5	2.6%	122.2	8.6%
CS&M	117.6	5.1%	115.4	(1.9%)	116.8	1.2%	121.5	4.0%
	$454.9	**3.2%**	**$469.3**	**3.2%**	**$475.4**	**1.3%**	**$509.4**	7.2%

Finance & Administration
2009 04 29

14(b)

the transfer of costs associated with the town of Gillam and the Frontier School Division to the Capital & Other Tax classification to provide a more consistent representation of these costs.

2009/10 Forecast vs 2010/11 Forecast

The increase is primarily attributable to cost escalation and higher pension costs related to fund performance.

2010/11 Forecast vs 2011/12 Forecast

In addition to cost escalation, this increase is primarily attributable to the $15 million provision for IFRS, the Wuskwatim Generating station operating costs forecasted at $6 million, and additional expense related to the Waterways Management program forecasted at $5 million. A provision for cost saving measures has been embedded into the forecast to offset these major cost pressures.

Please see the following schedules for a breakdown of OM&A and EFTs. Appendix 4.4 provides an additional OM&A costs.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

Schedule 4.5.0
(000's)

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
President & CEO	$ 20,977	$ 22,155	$ 24,475	$ 25,429	$ 26,014
Corporate Relations	5,245	5,520	5,100	5,200	5,320
Corporate Planning & Strategic Analysis	1,986	2,075	3,700	6,300	6,445
Finance & Administration	99,133	103,320	108,755	109,967	112,496
Power Supply	127,610	142,183	145,000	148,100	151,506
Transmission	83,171	91,088	91,100	92,400	94,525
Customer Services & Distribution	98,373	103,762	107,300	109,000	111,507
Customer Care & Marketing	38,859	39,343	42,000	43,000	43,989
Business Unit Subtotal	**475,354**	**509,446**	**527,430**	**539,396**	**551,802**
Motor Vehicle Chargeout	(15,394)	(16,043)	(16,154)	(16,601)	(16,983)
Payroll Tax	(8,774)	(9,679)	(9,873)	(10,070)	(10,272)
Corporate Allocations & Adjustments	(4,930)	(3,824)	(8,775)	(9,666)	(10,160)
CICA Accounting Changes*	-	5,000	7,000	7,000	7,000
Provision for IFRS	-	-	-	-	15,000
Operating & Administration Charged to Centra	(56,270)	(59,042)	(60,160)	(61,343)	(62,570)
Capitalized Overhead	(67,289)	(66,198)	(67,964)	(69,021)	(70,447)
OM&A Costs Attributable to Electric Operations	**$ 322,697**	**$ 359,660**	**$ 371,504**	**$ 379,695**	**$ 403,370**

* Other CICA Accounting Changes totalling $4 million (beginning in 2009/10) are embedded within the Business Units

MANITOBA HYDRO **Schedule 4.5.1**
EQUIVALENT FULL TIME EMPLOYEES - ANNUAL RESULTS BY BUSINESS UNIT

	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
President & CEO	87	87	97	99	99
Corporate Relations	69	75	69	69	69
Corporate Planning & Strategic Analysis	19	20	23	38	38
Finance & Administration	986	999	1,042	1,043	1,043
Power Supply	1,470	1,576	1,757	1,785	1,785
Transmission	1,255	1,298	1,355	1,358	1,358
Customer Services & Distribution	1,640	1,671	1,708	1,711	1,711
Customer Care & Marketing	545	550	561	566	566
Total	6,071	6,276	6,613	6,669	6,669

Exhibit # MH-112
Transcript Pages #5484-5485

Manitoba Hydro Undertaking #122

Manitoba Hydro to provide directive by President to Vice-President of Business Units regarding cost constraint measures.

Please refer to the attached memo dated August 13, 2010 from Manitoba Hydro's President and Chief Executive Officer.

Cost constraint measures have been successful in reducing OM&A costs as indicated in the following schedule.

Electric OM&A Net of Accounting Changes
February 2010 versus February 2011

	Actual	
(in millions of dollars)	2010	2011
Total OM&A Expense 'Electric only'	$ 348.6	$ 349.2
CICA Accounting Changes		
Lower Stores Overhead rates and no longer Capitalized	(4.6)	(4.6)
Intangible Assets no longer Capitalized	(2.7)	(1.8)
Administrative & General Overhead no longer Capitalized	(3.7)	(3.7)
Provision for Accounting Changes	-	
Motor vehicle interest removed from capitalization		(3.8)
Capitalized Overhead rate change from 24% to 17%		(14.4)
Reclassification of Wire & Telecom Services to Other Revenue	(2.8)	(2.8)
Reclassification of Funding Agreement for Town of Gillam & Frontier School Division	4.6	4.6
Subtotal - Accounting Changes	(9.1)	(26.4)
OM&A Expense 'Electric only' (net of accounting changes)	$ 339.5	$ 322.8
Total reduction in OM&A net of accounting changes		$ (16.7)

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MANITOBA HYDRO
INTEROFFICE MEMORANDUM

FROM R.B. Brennan
President and Chief Executive Officer

TO See Below

DATE 2010 08 13

FILE

SUBJECT **COST CONSTRAINT MEASURES**

The economic downturn has had a significant impact on Manitoba Hydro's revenues and net income. For the quarter ended June 30, 2010, Manitoba Hydro will be reporting its first quarterly loss since the severe drought of 2002 - 2004. In response to the current conditions, it will be necessary to expand measures already underway to constrain costs and improve operational efficiencies.

The following additional measures are being implemented:

1) **Further Restrictions on Non-Essential Travel Including In-Province Travel**

While the current out-of-province travel restrictions have been successful in moderating the growth in travel expense to some extent, Corporate travel expense totaled $32.4 million in 2009/10 – a 2.4% increase over the previous year. Over the past five years, travel expense has increased at an average annual rate of 6.6% per year.

Effective immediately, all out-of-province travel will be further restricted and all in-province travel will be limited to the extent necessary to meet service and work requirements. All options to reduce travel costs will be considered, including expanded use of telecommunication technologies, reduced meeting frequency, and reduced fleet utilization.

2) **A Freeze on the Filling of all Vacant Staff Positions**

Wages, salaries and benefits account for close to 75% of Manitoba Hydro's total operating expense. Over the past five years, this component of operating expense increased at an average rate of 5.0% per year including a 6.2% increase over the past year. Equivalent Full-Time Employees (EFTs) peaked at an all-time high of 6620 during 2009/10.

Effective immediately, the filling of all vacant positions in Pay Grades 33 and above will require the approval of the President and Chief Executive Officer. The filling of all vacant positions below Pay Grade 33 will require the approval of a Vice-President.

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3) **A Reduction in Overtime Costs**

Overtime costs have grown at a very significant average rate of 8.3% per year over the past five years. In 2009/10, overtime costs exceeded $50 million, an increase of 9.6% over the previous year.

While overtime is an essential component of providing safe and reliable energy services to our customers, overtime costs must be reduced and each Business Unit will be expected to demonstrate that this is being accomplished.

4) **Changes to Banked Vacation, Vacation Carryover and Vacation Cashout**

The following changes will be implemented to the vacation banking policies:

- Effective immediately, all new employee hires will have a banked vacation maximum capability of 75 days.

- Effective April 1, 2011, all existing employees will have their banked vacation maximum capability reduced to 150 days. All employees with over 150 days of banked vacation at April 1, 2011 will be grandfathered until their balances are reduced to 150 days (either through utilization or cashing out).

- Effective with the fiscal year ending March 31, 2011, the maximum vacation carryover will be limited to a cumulative total of 20 days. Exceptions will only be granted for exceptional circumstances and will require the approval of the President and Chief Executive Officer. All cumulative vacation balances in excess of 20 days will be forfeited (unless banked within the previously referenced limits).

5) **A Potential Freeze on Executive and Management Salaries**

Depending upon the effectiveness of other measures and the financial results of the Corporation over the next several months, it may be necessary to implement a freeze on salary increases for Executive and Management staff. Because the next increase in salaries for this group is not scheduled to take place until December 31, 2010, the financial and economic situation will be closely monitored and further actions may be taken as conditions warrant. Further communication on this important and sensitive issue will be provided on a regular and timely basis.

6) Capital Rationalization

As you know, Manitoba Hydro is embarking on a major capital expansion program. While planned investments in new generation and transmission are very large and will require debt financing, regular or "base capital" will continue to be funded through internally generated funds. To accomplish this, all proposed capital additions must be rigorously scrutinized and only those capital items necessary "to provide an ongoing safe and reliable supply of energy in the most efficient and environmentally sensitive manner" will be approved.

The above measures are being implemented in recognition of the serious economic conditions and as a continuation of the prudent fiscal management that is consistently applied at Manitoba Hydro.

I greatly appreciate the ongoing dedication, innovation, and cooperation of all employees in the fulfillment of our commitments to the energy consumers of Manitoba.

Bob Brennan

RBB/gt

SAME MEMORANDUM TO:

K.R.F. Adams
E.R. Kristjanson
L.J. Kuczek
G.B. Reed
K.M. Tennenhouse
T.E. Tymofichuk
V.A. Warden
C.E. Wray

c: G.P. Schneider
L.R. Wilson
R.V. Orr

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PUB/MH I-64

Reference: **Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels**

a) **Please file expanded tables found on pages 10 and 12 to include the years 2003/04 to 2008/09.**

ANSWER:

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY BUSINESS UNIT

(In thousands of $)	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
President & CEO	$ 22,963	$ 24,230	$ 31,578	$ 28,835	$ 28,328	$ 28,692	$ 29,239	4.8%
Corporate Relations	5,245	5,520	4,697	4,739	3,025	4,491	4,585	0.9%
Finance & Administration	99,521	103,722	108,914	106,528	107,443	114,343	118,816	3.0%
Power Supply	127,610	142,183	147,073	150,120	155,084	177,882	187,031	6.7%
Transmission	83,171	91,088	92,302	90,493	89,261	104,662	107,265	4.5%
Customer Services & Distribution	98,373	103,762	111,068	106,707	110,045	130,355	132,916	5.4%
Customer Care & Marketing	38,472	38,942	42,395	41,446	43,703	52,249	95,922	19.4%
Business Unit Total*	475,354	509,446	538,027	528,867	536,889	612,673	675,774	6.2%

*Note: Does not include allocations to capital and Centra Gas.

MANITOBA HYDRO
EQUIVALENT FULL TIME EMPLOYEES BY BUSINESS UNIT

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
President & CEO	106	107	116	123	127	126	126	3.0%
Corporate Relations	69	75	73	69	69	75	75	1.7%
Finance & Administration	993	1,006	1,010	1,009	983	1,003	1,003	0.2%
Power Supply	1,470	1,576	1,679	1,796	1,853	1,972	1,972	5.0%
Transmission	1,256	1,298	1,342	1,365	1,354	1,385	1,385	1.7%
Customer Services & Distribution	1,640	1,671	1,678	1,704	1,701	1,731	1,731	0.9%
Customer Care & Marketing	538	543	532	528	521	549	549	0.4%
Total	6,071	6,276	6,429	6,594	6,608	6,842	6,842	2.0%

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PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

d) Please indicate to what extent costs from each business unit are capitalized in 2003/04 to 2015/16.

ANSWER:

Business Unit OM&A costs presented in Appendix 5.6 are net of costs capitalized through capital order activity charges. Please see the following schedule for a breakdown of costs capitalized for each business unit.

MANITOBA HYDRO
COSTS CAPITALIZED BY BUSINESS UNIT (000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast [1]
President & CEO	$ 841	$ 948	$ 496	$ 331	$ 555	$ 675	$ 689
Corporate Relations	3,449	4,364	4,872	4,934	5,301	4,630	4,723
Finance & Administration	10,559	10,494	10,794	12,482	12,438	12,297	12,543
Power Supply	41,181	45,191	54,629	63,199	74,028	72,093	73,535
Transmission	50,131	53,067	61,254	67,377	72,554	67,637	68,989
Customer Services & Distribution	76,102	80,943	82,373	84,995	92,995	79,432	81,021
Customer Care & Marketing	10,069	10,164	9,879	10,226	10,780	9,299	9,485
	$ 192,331	$ 205,169	$ 224,297	$ 243,545	$ 268,651	$ 246,065	$ 250,986

[1] The forecasted capitalized costs for 2013/14 do not include the impact of IFRS changes on capital order activity charges. Detailed budgets by business unit/division for the 2013/14 fiscal year incorporating the changes under IFRS will be prepared following approval of IFF12.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

f) Please indicate the current number of unfilled EFT's

ANSWER:

The budgeted EFT complement for August 2012 was 6708 as compared to the actual EFT level of 6494, resulting in 214 unfilled EFTs.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

g) **Please provide a comparison of the EFT's forecast at the last GRA for 2009/10, 2010/11 and 2011/12 [PUB/MH I-34 (R)] and for each difference please indicate the attributed payroll difference between what was forecast in IFF09 versus actual.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-37(b).

The attributed payroll difference between what was forecast in IFF09 versus actual would be a decrease in wages & salaries and overtime of approximately $12.2 million in 2009/10, $4.9 million in 2010/11 and $4.2 million in 2011/12.

PUB/MH I-64

Reference: **Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels**

h) Please refile the schedule on page 7 to agree with the OM&A reflected in IFF11-2.

ANSWER:

Please see the Operating, Maintenance and Administrative Costs by Cost Element schedule adjusted to reconcile with the OM&A reflected in IFF11-2.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2009/10 Actual	2010/11 Actual	2011/12 Forecast	2012/13 Forecast	2013/14 Forecast	Average Annual % Inc/(Dec)
Wages, Salaries	$ 407,988	$ 425,158	$ 448,371	$ 476,887	$ 486,425	4.5%
Overtime	50,307	50,704	50,680	56,005	57,126	3.3%
Employee Benefits	83,013	95,376	102,354	109,649	111,842	7.8%
Employee Safety & Training	4,284	3,863	4,165	4,914	5,013	4.5%
Travel	32,435	32,594	32,131	32,405	33,053	0.5%
Motor Vehicle	24,281	24,436	25,201	24,784	25,280	1.0%
Materials & Tools	26,897	28,105	26,900	27,173	27,716	0.8%
Consulting & Professional Fees	14,814	11,157	11,402	11,639	11,872	-4.6%
Construction & Maintenance Services	20,109	22,657	18,838	18,706	19,080	-0.7%
Building & Property Services	22,931	21,944	20,624	22,396	22,843	0.1%
Equipment Maintenance & Rentals	14,379	14,165	14,150	14,476	14,766	0.7%
Consumer Services	5,798	5,086	4,982	5,284	5,389	-1.6%
Collection Costs	4,599	4,497	4,521	4,347	4,434	-0.9%
Customer & Public Relations	8,155	7,905	6,797	6,949	7,088	-3.2%
Sponsored Memberships	1,325	1,917	996	1,081	1,103	1.8%
Office & Administration	15,320	14,316	14,826	15,263	15,569	0.5%
Computer Services	983	1,003	1,007	909	927	-1.3%
Communication Systems	1,772	1,678	1,796	1,683	1,717	-0.6%
Research & Development Costs	3,952	3,651	4,136	3,509	3,579	-1.9%
Miscellaneous Expense	1,190	1,264	1,278	1,213	1,237	1.1%
Contingency Planning	-	-	1,577	278	2,875	
Operating Expense Recovery	(21,580)	(23,004)	(16,256)	(9,787)	(9,983)	-15.1%
Total Costs	722,951	748,471	780,476	829,765	848,951	4.1%
Capital Order Activities	(224,298)	(243,545)	(265,803)	(246,065)	(250,986)	3.1%
Capitalized Overhead	(60,151)	(47,336)	(52,742)	(69,434)	(70,823)	5.9%
Operating and Administration Charged to Contra	(60,951)	(60,644)	(64,000)	(67,300)	(68,646)	3.0%
IFRS Changes					71,574	
Wuskatim GS for Full Year In-Service	-	-	-	-	1,754	
OM&A Attributable to Electric Operations	**$ 377,551**	**$ 396,946**	**$ 397,931**	**$ 446,966**	**$ 531,825**	
Less:						
Accounting Changes	11,240	30,910	34,973	67,059	139,974	
Wuskwatim				7,881	9,635	
OM&A Attributable to Electric Operations after adjusting for subsidiaries, accounting changes and Wuskwatim	**$ 366,311**	**$ 366,036**	**$ 362,958**	**$ 372,026**	**$ 382,216**	

Please note the 'OM&A Attributable to Electric Operations' does not include subsidiaries.

PUB/MH I-64

Reference: Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels

i) Please provide a comparison of the OM&A by cost element for the years 2009/10, 2010/11 and 2011/2 from PUB/MH II – 23 (from the 2011 & 2012 GRA) with the amount presented in Appendix 5.6 page 7 for those years. Please indicate the dollar and percentage difference for each line item and explain the reason for the variances; in particular the increases in labour costs for 2010/11 & 2011/12 given the reduction in actual EFT's from that forecast at the last GRA.

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-59(d).

The increase in labour costs for 2010/11 and 2011/12 are primarily due to wage settlements, net of the reduction in actual EFT's as compared to the forecast at the last GRA.

PUB/MH I-64

Reference: **Tab 5 Appendix 5.6 Pages 10 – 13 of 13, Schedule 4.5.1 2011 & 2012 GRA, Staffing Levels**

j) Please provide the compound annual growth rate for 2009/10 through 2011/12 by each line item last year and provide the same information for this year.

ANSWER:

The attached table provides 2009/10 through 2011/12 actual results as filed in Appendix 5.6 and the forecast for the same fiscal years as filed in the prior hearing.

MANITOBA HYDRO
OPERATING, MAINTENANCE AND ADMINISTRATIVE COSTS BY COST ELEMENT

(In thousands of $)	2009/10 Actual	2010/11 Actual	2011/12 Actual	Fiscal 2009/10-2011/12 Compounded Annual Growth %	As per 2010/11, 2011/12 GRA 2009/10 Actual	2010/11 Forecast	2011/12 Forecast	Fiscal 2009/10-2011/12 Compounded Annual Growth %
Wages, Salaries	$ 407,988	$ 425,158	$ 451,925	5.2	$ 407,988	$ 415,215	$ 424,765	2.0
Overtime	50,307	50,704	54,987	4.5	50,307	48,061	49,166	-1.1
Employee Benefits	82,674	95,376	104,444	12.4	82,674	93,035	95,175	7.3
Employee Safety & Training	4,623	3,863	3,909	-8.0	4,623	4,747	4,856	2.5
Travel	32,435	32,594	31,266	-1.8	32,435	32,963	33,721	2.0
Motor Vehicle	24,281	24,436	28,676	8.7	24,281	23,114	23,646	-1.3
Materials & Tools	26,897	28,105	26,663	-0.4	26,897	26,178	26,780	-0.2
Consulting & Professional Fees	14,814	11,157	10,250	-16.8	14,814	10,904	11,155	-13.2
Construction & Maintenance Services	20,109	22,657	21,228	2.7	20,109	21,785	22,286	5.3
Building & Property Services	22,931	21,944	21,386	-3.4	22,931	20,671	21,146	-4.0
Equipment Maintenance & Rentals	14,379	14,165	13,388	-3.5	14,379	13,858	14,177	-0.7
Consumer Services	5,798	5,086	5,365	-3.8	5,798	5,683	5,814	0.1
Computer Services	983	1,003	861	-6.4	983	696	712	-14.9
Collection Costs	4,599	4,497	4,034	-6.3	4,599	4,542	4,646	0.5
Customer & Public Relations	8,155	7,905	8,093	-0.4	8,155	6,014	6,152	-13.1
Sponsored Memberships	1,325	1,917	1,608	10.1	1,325	1,267	1,296	-1.1
Office & Administration	15,320	14,316	14,277	-3.5	15,320	15,703	15,857	1.7
Communication Systems	1,772	1,678	1,683	-2.5	1,772	1,603	1,640	-3.8
Research & Development Costs	3,952	3,651	2,796	-15.9	3,952	4,110	4,205	3.2
Miscellaneous Expense	1,190	1,264	2,032	30.7	1,190	1,087	1,112	-3.3
Contingency Planning	-	-	-	0.0	-	5,417	3,921	0.0
Operating Expense Recovery	(21,580)	(23,004)	(21,716)	0.3	(21,580)	(16,497)	(16,670)	-12.1
Total Costs	722,951	748,471	787,155	4.3	722,951	740,156	755,557	2.2
Capital Order Activities	$ (224,298)	$ (243,545)	$ (268,651)	9.4	$ (224,298)	$ (235,040)	$ (239,741)	3.4
CICA Accounting Changes*	-				9,000	9,000	9,000	0.0
Provision for IFRS					-	18,000	13,500	
Capitalized Overhead	(60,151)	(47,336)	(53,084)	-6.1	(69,151)	(71,021)	(72,447)	2.4
Operating and Administration Charged to Centra	(60,951)	(60,644)	(62,117)	1.0	(60,951)	(63,400)	(64,000)	2.5
OM&A Attributable to Electric Operations	**$ 377,551**	**$ 396,946**	**$ 403,303**	3.4	**$ 377,551**	**$ 397,695**	**$ 401,870**	3.2

* Other CICA Accounting Changes totalling $4.0 million in 2009/10 & future years are embedded within the Total Costs

16

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

a) **Please provide a table/ matrix of EFT per 1,000 of GWh, per $millions of domestic revenue, per domestic customers.**

	1999/00			*2011/12*
EFT's				
EFT per 1,000 GWH of domestic Supply				
EFT per 1000 GWH of total supply				
EFT per number of domestic customers				
EFT's per $Millions of domestic revenue				
Average Salary & Benefits per EFT				
Annual Wage Rate Adjustment (Union)				
Average Wage Rate Adjustment – Non Union				

Please provide rows in the above table including all data used to calculate the ratios above.

ANSWER:

Please see the following tables.

	Information Requested				
	2007/08	2008/09	2009/10	2010/11	2011/12
EFTs	6,071	6,276	6,429	6,594	6,608
EFT per 1000 GWh of domestic supply	253.12	258.43	275.98	277.26	281.20
EFT per 1000 GWh of total supply	171.72	181.77	189.31	193.36	198.83
EFT per number of domestic customers	0.01	0.01	0.01	0.01	0.01
EFT per $ millions of domestic revenue	5.65	5.57	5.62	5.49	5.55
Average Salary & Benefits per ST EFT	$ 76,961	$ 78,568	$ 82,283	$ 83,466	$ 88,741
Annual Wage Rate Adjustment*		2.1%	4.8%	1.5%	6.3%

* Annual Wage Rate Adjustment comes from CAC/MH I-39(b).

16A

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

b) Please provide a schedule which indicates the total increase in salary wage, benefits and overhead [both OM&A and Capitalized] related to changes in EFT's for each of the years 1999/00 to 20013/14.

ANSWER:

The total of salaries, wages, overtime and benefits related to EFTs is provided in the following table:

Fiscal Year	Wages & Salaries	Overtime	Benefits	Total	EFTs
2007/08	$ 359 249	$ 41 781	$ 76 807	$ 477 838	6 071
2008/09	$ 380 031	$ 45 890	$ 83 671	$ 509 592	6 276
2009/10	$ 407 988	$ 50 307	$ 83 013	$ 541 307	6 429
2010/11	$ 425 158	$ 50 704	$ 95 376	$ 571 238	6 594
2011/12	$ 451 925	$ 54 987	$ 104 444	$ 611 356	6 608
2012/13 Forecast	$ 476 887	$ 56 005	$ 109 649	$ 642 542	6 842
2013/14 Forecast	$ 486 425	$ 57 126	$ 111 842	$ 655 393	6 842

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

c) **Please indicate the total increases in wages and benefits attributable to new labour agreements on IFF11-2.**

ANSWER:

The recently concluded labour agreement with IBEW provided for the following increases in wages:

January 1, 2012	2.5%
April 1, 2012	2.0% market adjustment for trades classifications
January 1, 2013	0.0%
January 1, 2014	2.75%
January 1, 2015	2.75%

The impact of the IBEW wage settlement on the IFF is as follows:

2012/13	$6.2 million
2013/14	$1.2 million
2014/15	$4.8 million

ln c

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

d) Please provide a schedule which indicates the salary, wages and benefits as a percentage of OM&A, percentage of domestic revenue, and salary wages and benefits capitalized,

ANSWER:

Please see the following tables for salary, wages and benefits information for 2007/08 through 2013/14.

Labour & Benefits includes salary, wages, overtime and benefits.

(in thousands of $)

Labour and Benefits as a Percentage of OM&A and Domestic Revenue	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Labour and Benefits	$477,838	$509,592	$541,307	$571,238	$611,356	$642,542	$655,393
Total OM&A Costs (before capitalization)	$638,594	$687,149	$722,951	$748,471	$787,156	$829,765	$848,951
Labour and Benefits as a % of OM&A	74.8%	74.2%	74.9%	76.3%	77.7%	77.4%	77.2%
Domestic Revenue (GCR)	$1,074,581	$1,126,812	$1,144,891	$1,200,381	$1,191,117	$1,335,571	$1,399,088
Labour and Benefits as a % of GCR	44.5%	45.2%	47.3%	47.6%	51.3%	48.1%	46.8%

Activity charges form the basis for cost allocation to capital projects and are built up from a number of cost components including salaries, wages and benefits, meals & accommodations, transportation costs etc. Overhead is also capitalized as a percentage of activity charges and includes a number of cost categories, some of which have a labour and benefit component. Direct quantification of the labour and benefit component of both activity charges and overhead is not available as the approach taken by Manitoba Hydro is one of cost allocation. The following provides an estimate of the amount of labour and benefits capitalized through activity charges and associated overhead. Please note that 2013/14 does not reflect the impact of IFRS changes.

(in thousands of $)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Capital Order Activities	($192,338)	($203,077)	($224,298)	($243,545)	($268,651)	($246,065)	($250,986)
Capitalized Overhead	($67,289)	($65,743)	($60,151)	($47,336)	($53,084)	($69,434)	($70,823)
Labour & Benefits Capitalized	($185,900)	($193,500)	($207,600)	($221,200)	($246,800)	($264,400)	($269,700)

PUB/MH I-38

Reference: Tab 5 Staffing Appendix 5.6 Page 10

e) Please provide the total Labour & Benefits Costs and the dollar and percentage of Labour & Benefits Capitalized for each of the years 1999/00 to 2013/14. Include the EFT equivalent in each year of Labour & Benefits capitalized.

ANSWER:

Please see schedule:

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Labour and Benefits	$477,838	$509,592	$541,307	$571,238	$611,356	$642,542	$655,393
Labour & Benefits Capitalized							
In dollars	$185,900	$193,500	$207,600	$221,200	$246,800	$264,400	$269,700
as a percentage of total Labour and Benefits	39%	38%	38%	39%	40%	41%	41%
EFTs (S/T & O/T) capitalized	2 369	2 397	2 479	2 566	2 678	2 825	2 825

PUB/MH II-2

Subject: **Tab 3 Corporate Overview**
Reference: **PUB/MH I-5 (c)**

b) Please update the response to include the % of Labour and Benefits Capitalized (based on 75% proportion of Capital Order Activity) and explain the factors that have led to the increase in the proportion of labour and benefits capitalized since 2004/05

ANSWER:

The following chart provides the % of labour and benefits capitalized to total labour & benefits:

	2003/04 Actual	2004/05 Actual	2005/06 Actual	2006/07 Actual	2007/08 Actual	2008/09 Actual	2009/10 Forecast	2010/11 Forecast	2011/12 Forecast
Labour & Benefits Capitalized	$111,577	$118,297	$127,844	$132,744	$144,254	$153,881	$173,305	$176,280	$179,806
Total Labour and Benefits	$398,449	$423,093	$440,473	$457,233	$477,838	$509,592	$544,952	$556,311	$569,106
% of Lab. & Ben Cap./Total	28%	28%	29%	29%	30%	30%	32%	32%	32%

The increase in percentage of labour and benefits capitalized over the period is related to the expanded capital program, including significant new generation/transmission projects over the same period.

PUB/MH II-6

Reference: PUB/MH I-9 (b)/ PUB/MPI I-75

The question requested the comparison with electric utilities in Canada including BC, Saskatchewan, Ontario and Quebec.

a) **Please provide the OM&A comparisons with Ontario, Quebec, Saskatchewan and Alberta.**

ANSWER:

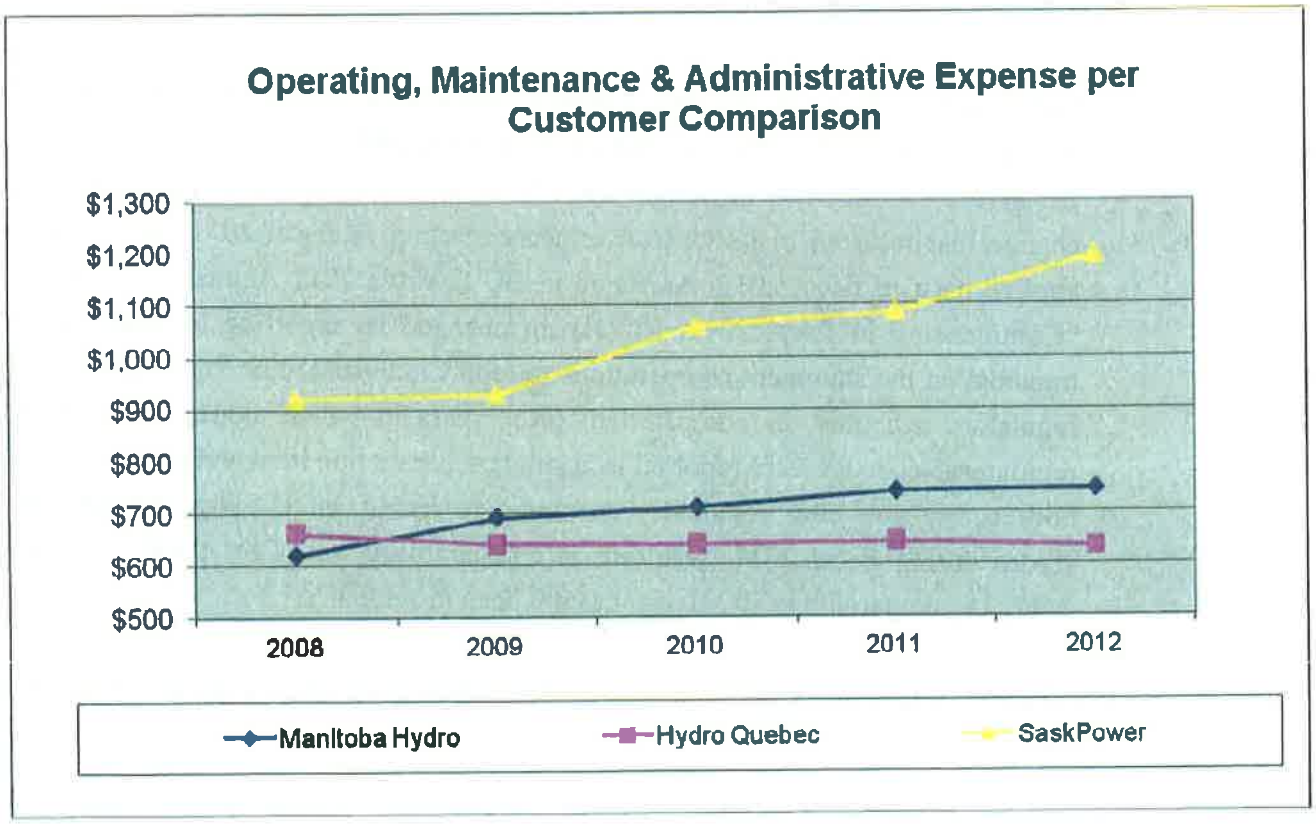
Please see the following table and charts for an OM&A comparison of Manitoba Hydro, Hydro Quebec and SaskPower. The province of Ontario and the province of Alberta do not have vertically integrated electric utilities and therefore are not comparable to Manitoba, Quebec and Saskatchewan.

As indicated in the response to PUB/MH I-75:

- SaskPower's OM&A is no longer directly comparable due to the conversion to IFRS starting in fiscal 2011 with the restatement of fiscal 2010 results.
- BC Hydro's OM&A is no longer directly comparable due to a significant accounting change that resulted in its OM&A expense starting in fiscal 2011, being retroactively applied back to fiscal 2010. As stated in BC Hydro's 2011 Annual report, on page 32, "Commencing in fiscal 2011, BC Hydro changed its reporting of regulatory account transfers on the statement of operations to report individual line items net of transfers to regulatory accounts, as compared to prior years in which aggregate net transfers to regulatory accounts were reported as a single separate line item and income was reported both before and after regulatory account transfers." BCTC was integrated with BC Hydro during fiscal 2011, resulting in comparability issues for fiscal 2011 and fiscal 2012. A comparison to BC Hydro has not been provided.

The Hydro Quebec and SaskPower information comes from their 2011 Annual Reports.

	2008	2009	2010	2011	2012
Manitoba Hydro OM&A	$ 323	$ 364	$ 378	$ 397	$ 403
Hydro Quebec OM&A	2,556	2,502	2,527	2,579	2,571
SaskPower OM&A	416	427	495	513	575
Manitoba Hydro Customers	521,599	527,472	532,359	537,299	542,681
Hydro Quebec Customers	3,868,972	3,913,444	3,960,332	4,011,789	4,060,195
SaskPower Customers	451,713	460,006	467,329	473,007	481,985
Manitoba Hydro GWh	35,354	34,528	33,961	34,102	33,235
Hydro Quebec GWh	208,156	206,603	203,181	203,842	207,693
SaskPower GWh	18,774	18,601	17,989	18,862	19,675
OM&A per Customer					
Manitoba Hydro	$ 619	$ 691	$ 709	$ 739	$ 743
Hydro Quebec	661	639	638	643	633
SaskPower	921	928	1,059	1,085	1,193
OM&A per GWh					
Manitoba Hydro	$ 9,128	$ 10,550	$ 11,117	$ 11,640	$ 12,135
Hydro Quebec	12,279	12,110	12,437	12,652	12,379
SaskPower	22,158	22,956	27,517	27,198	29,225



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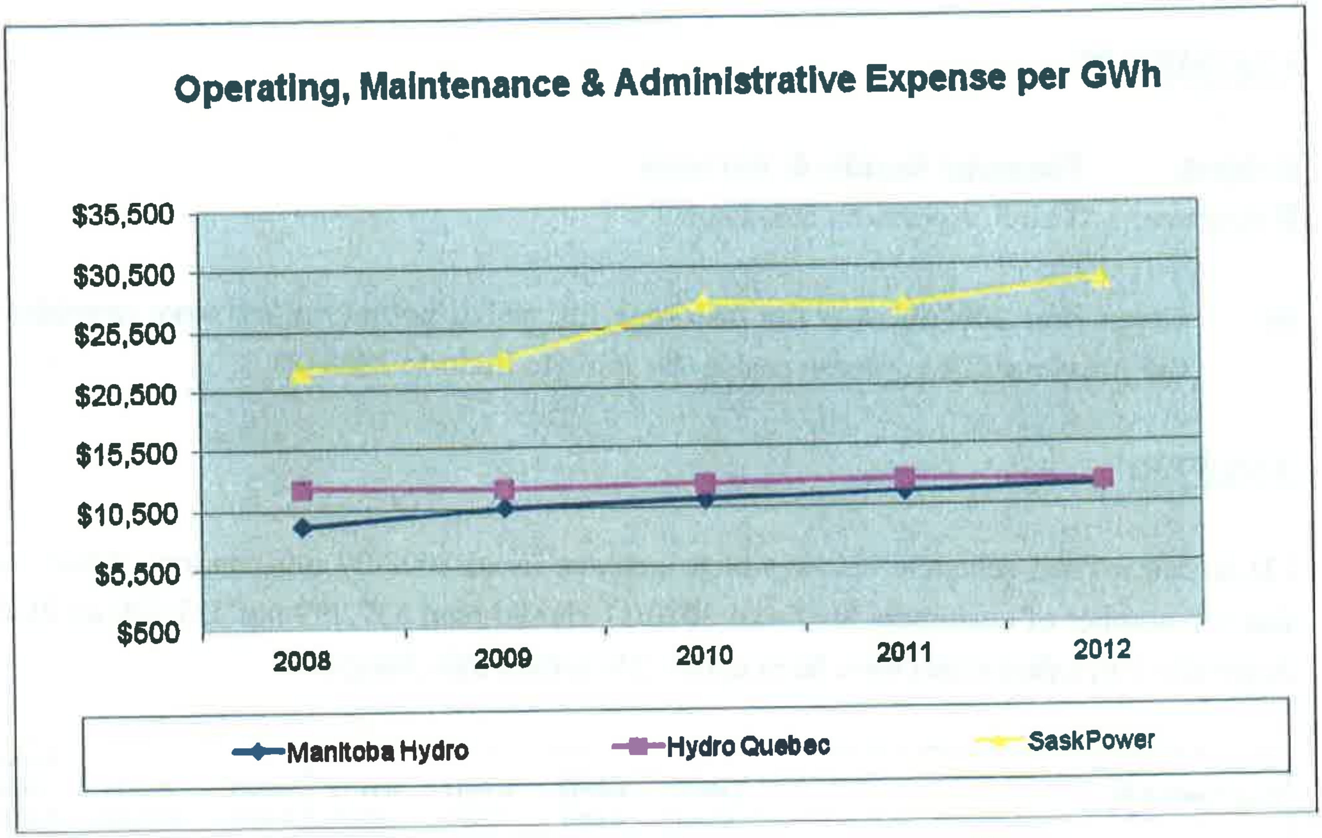
Operating, Maintenance & Administrative Expense per GWh
$35,500
$30,500
$25,500
$20,500
$15,500
$10,500
$5,500
$600
2008
2009
2010
2011
2012
Manitoba Hydro
Hydro Quebec
SaskPower

CAC/MH I-37

Subject: **Financial Results & Forecast**
Reference: **Tab 5, Appendix 5.6, Page 1**

a) Given that 2007/08 was the last year for which actual values were provided in the previous GRA, please revise the table to include 2008/09.

ANSWER:

Please see revised schedule below which includes fiscal 2008/09 information. Please note that the number of customers for fiscal 2010/11 should read 537,299 not 537,229 as filed in Appendix 5.6; calculations have been updated to reflect this change.

(in thousands of $)	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual Increase
Electric OM&A (per Annual Report)	$ 369 103	$ 379 697	$ 403 067	$ 410 717	$ 453 497	$ 538 770	
Less: Subsidiaries	4 816	2 146	6 121	7 414	6 531	6 945	
Accounting Changes	$ 13 000	11 240	30 910	34 973	67 059	139 974	
Wuskwatim					7 881	9 635	
Electric OM&A after adjusting for subsidiaries, accounting changes and Wuskwatim	$ 351 287	$ 366 311	$ 366 036	$ 368 330	$ 372 026	$ 382 216	
% Increase	8.86%	4.28%	-0.08%	0.63%	1.00%	2.74%	2.87%
Number of Customers	527 472	532 359	537 299	542 681	549 150	555 651	0.87%
Cost Per Customer	$ 666	$ 688	$ 681	$ 679	$ 677	$ 688	
% Increase (Decrease)	7.65%	3.32%	-0.99%	-0.37%	-0.19%	1.54%	1.63%
Canadian CPI	1.20%	1.40%	3.30%	1.90%	2.10%	2.00%	1.98%

1h

17

MANITOBA	Board Order 5/12
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	January 17, 2012

Before: Graham Lane CA, Chairman
Robert Mayer Q.C., Vice-Chair

A FINAL ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR INCREASED 2010/11 AND 2011/12 RATES AND OTHER RELATED MATTERS

7 A.

anticipated mitigation payments to be incurred, the Corporation has recorded a liability of $129 million as of March 31, 2010.

MH has also entered into agreements with the Province whereby MH has assumed obligations of the Province with respect to certain northern development projects. MH assumed obligations totalling $145 million for which water power rental charges were fixed until March 31, 2001. The remaining liability outstanding as of March 31, 2010 was $12 million. All mitigation cost obligations, including those Provincial obligations assumed by MH, are capitalized and amortized over the remaining life of the generation and transmission assets to which they pertain.

9.5.0 INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

9.5.1 IFRS Transition

International Financial Reporting Standards (IFRS) will be adopted by Canadian Generally Accepted Accounting Principles (GAAP) to be implemented effective January 1, 2011. Canadian utilities have been granted an optional one-year deferral of the implementation of IFRS to years commencing on or after January 1, 2012. This allows for a transition of accounting standards that do not recognize rate-regulated assets and liabilities. MH will be required to prepare IFRS-compliant financial statements for its fiscal year 2012/13 with comparative financial information for 2011/12.

The implementation of IFRS has prompted MH to delay undertaking Board-requested studies, including an independent benchmarking study of key performance metrics comparing MH's operations with other utilities as well as an Asset Condition Assessment Report. These studies were ordered in Directive 4 and Directive 7, respectively, of Order 150/08.

7p

9.5.2 *Rate-Regulated Assets & Liabilities*

IFRS does not currently recognize rate-regulated accounting. If standards remain unchanged, MH will be required to write off the accumulated balance of its rate-regulated assets against retained earnings and expense expenditures previously deferred due to rate regulation as incurred.

MH stated that its rate-regulated assets were $299 million as of March 31, 2010, of which $229 million relate to electric operations and $70 million to gas operations. A major component of rate-regulated assets is approximately $40 million in annual Power Smart DSM program costs. Currently, DSM expenditures are amortized over a 10-year period. Under IFRS, the amount would be expensed in the year incurred.

With respect to the implications of conversion to IFRS on the rate-setting process, MH believes that any changes in accounting practices can be accommodated within the rate-setting framework. Since IFRS result in changes to the timing when certain costs will be recognized in its operating accounts, MH believes that some mechanism may be required to defer certain costs for rate-setting purposes. MH stated that it would provide the Board with alternatives to consider at the appropriate time.

9.5.3 *Other Accounting Impacts*

Canadian GAAP converged with IFRS related to accounting for Goodwill and Intangible Assets in fiscal 2010. IFRS does not allow planning studies to be capitalized, which were previously amortized over 15 years, unless there is assurance that the facilities will be built. As a result, MH was required to write off $37 million in deferred costs including computer development, general advertising and promotion and planning studies to retained earnings, impacting MH's 2008/09 retained earnings. Included in the write off were $25.2 million in unamortized planning studies.

IFRS also has more restrictive requirements for the type of expenditures that can be capitalized. IFRS does not allow advertising and promotional activities, administrative and other general overhead expenditures, property and business taxes and interest on common assets to be capitalized. MH adjusted its overhead capitalization policy accordingly by reducing the amount of overhead capitalized to capital projects from 24% to 17% for 2010/11.

As a result of the accounting policy changes, MH reduced its total capitalized overhead by $5 million in 2008/09 and an additional $4 million in 2009/10. It also made a provision of $18 million in 2010/11 and $14 million in 2011/12, reflecting a reduction in the overhead rate.

9.6.0 O&A COST CONTROL PROCESS

MH's forecast provides for a productivity factor in the order of 0.5% to 1% annually in the setting of its business unit O&A targets. In response to the economic downturn, MH has put in place measures to constrain the increase of O&A, including a freeze on hiring of new positions (with the exception of line trades trainees), restrictions on out-of-province travel, rationalization of fleet vehicles, extension of service lives of computers and equipment and reduction of overtime costs where possible.

MH indicated that such measures were short-term and that cost containment measures would not compromise system safety and reliability. MH stated that such steps had resulted in reducing the year-over-year changes in O&A by 5% or $16 million in the first 10 months of the current fiscal year.

In Order 116/08 the Board stated:

> *"Although Hydro's operating and administrative expenses appear reasonable, the Board urges Hydro to continue to control these expenses through aggressive cost control initiatives and management of the labour force. The Board appreciates that some operating and administration expenses, particularly payments to the Province, are beyond Hydro's control. However, it remains necessary for Hydro to continue to be diligent in taking steps to control all such costs and improve efficiencies. Corporate Performance measures such as operating and administration cost per customer or per kW.h targets are of great assistance in*

AUC
Alberta Utilities Commission

Fifth Avenue Place, 4th Floor, 425 - 1 Street SW
Calgary, Alberta Canada T2P 3L8
Phone (403) 592-8845
www.auc.ab.ca

Rule 026

Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards

The Alberta Utilities Commission (AUC/Commission) has approved this rule on May 19, 2009.

Contents

Definitions

1 In this rule,

(a) "Existing Accounting Practice" means the accounting procedures and policies in use by a Utility, that have been approved by the Commission for rate-making purposes, immediately prior to the adoption of this Rule;

(b) "Existing Canadian GAAP" means the widely accepted set of rules, conventions, standards, and procedures for reporting financial information, as established by the Accounting Standards Board;

(c) "First IFRS-Compliant GRA/GTA" means the first General Rate Application/General Tariff Application filed by a Utility which includes the Utility's IFRS Adoption Date in the forecast test period;

(d) "IAS" or "International Accounting Standards" refers to the standards issued by the International Accounting Standards Committee from 1973 to 2000, when it was replaced by the International Accounting Standards Board (IASB), and as amended or replaced by the IASB;

Appendix I – Guiding Principles

These Guiding Principles are all equally important and are to be viewed as a collective set of principles rather than a list of individual statements.

- The methodologies used by the AUC to establish just and reasonable rates have not always been the same as those used for external financial reporting purposes. The Commission has and will retain the authority to establish Regulatory Accounting and regulatory reporting requirements and as such, IFRS requirements will not be the sole driver of regulatory requirements.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will continue to be based on historical, sound regulatory principles. Examples of these principles can be found in statutes, regulatory and court decisions and regulatory texts and include intergenerational equity, minimizing rate volatility and use of historical costs rather than fair market, or any other values.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will, in considering IFRS requirements, balance the effects on customer rates and shareholders' return. Any shifting of risk between customers and shareholders will be minimized.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will be aligned as much as possible with IFRS. In establishing any future Regulatory Accounting and regulatory reporting requirements that deviate from IFRS, the Commission will ensure that any such deviations and their impact are in the public interest.

- Future Regulatory Accounting and regulatory reporting requirements established by the Commission will be universal and standardized for all utilities while still recognizing that utility-specific issues can be addressed through that utility's applications.

Ontario Energy Board

Ontario

EB-2008-0408

Report of the Board

Transition to International Financial Reporting Standards

July 28, 2009

Appendix 2: Summary of Board Policy

1. Principles

1.1 The methodologies used by the Board to establish just and reasonable rates have not always been the same as those used for external financial reporting purposes. The Board has and will retain the authority to establish regulatory accounting and regulatory reporting requirements. While IFRS accounting requirements are an important consideration in determining regulatory requirements, the objective of just and reasonable rates will continue to be the primary driver of such requirements.

1.2 Future regulatory accounting and regulatory reporting requirements established by the Board will continue to be based on sound regulatory principles. These principles include fairness, minimizing intergenerational inequity and minimizing rate volatility.

1.3 Future regulatory accounting and regulatory reporting requirements established by the Board will, in taking into account IFRS requirements, balance the effects on both customers and shareholders.

1.4 Future regulatory accounting and regulatory reporting requirements established by the Board will be aligned with IFRS requirements as long as that alignment is not inconsistent with sound regulatory rate making principles.

1.5 Future regulatory accounting and regulatory reporting requirements established by the Board will be universal and standardized for all utilities, while recognizing that utility-specific issues can be addressed through a utility's applications. The Board will not require modified IFRS filing and reporting requirements for utilities that are not otherwise required to adopt IFRS for financial reporting purposes.

Major Points of Departure between Existing Regulatory Accounting and Rate Making as Compared to IFRS

2. Regulatory Assets and Liabilities

2.1 The Board will continue to use deferral and variance accounts for rate making in appropriate circumstances, whether or not these accounts are recognized under IFRS.

2.2 The Board will continue to apply the existing approach in the use and establishment of deferral and variance accounts at this time. The Board may consider the review and adjustment of its existing approach when the rulings from the International Accounting Standards Board are received and the interpretation of IFRS becomes clearer.

CAC/MH I-36

Subject: **IFRS**
Reference: **Tab 5, Page 16 , Appendix 5.5, page 13 - 14**

Preamble: **MH states: In addition, Manitoba Hydro Power Smart programs costs, Site Remediation costs and Regulatory costs will now have to be expensed as incurred, as they will no longer be eligible to be treated as a rate regulated asset under IFRS. [emphasis added]**

MH also states: However, no decision as to the future direction of the ED [Exposure Draft] was reached. rather, because of the diversity in responses to the ED and the concern that diversity may arise in practice, IASB staff were directed to conduct further analysis and research and to present their findings at a future meeting. [emphasis added]

g) **Relative to the uncertainty regarding the treatment of rate regulated activities, including treatment of regulatory assets and liabilities, please complete the table below, showing how utilities in Canadian jurisdictions are dealing with IFRS for regulatory purposes and for external reporting purposes. In particular, please indicate whether regulatory assets and liabilities, such as deferral accounts and reserves are used for regulatory (ratemaking) purposes and whether the entity uses Canadian GAAP, US GAAP or IFRS under each of "Regulatory Purposes" and "External Purposes".**

ANSWER:

This response has been prepared based only on publicly available information of utilities and regulators with respect to financial reporting and rate setting under IFRS or US GAAP.

Manitoba Hydro is not in a position to provide a comprehensive response with respect to the treatment of regulatory assets and liabilities by the specified Canadian utilities and their respective provincial regulators.

Please see the following table for the information that was available to Manitoba Hydro:

Utility Name	Jurisdiction	Treatment of Regulatory Assets and Liabilities	
		Regulatory Purposes	External Purposes
BC Hydro	**BC**	It is MH's understanding, based on recent decisions by the BCUC, that regulatory assets and liabilities will continue to be used for rate setting purposes.	**Modified IFRS -** As directed by the BC Provincial Government, BC Hydro plans to transition to a modified version of IFRS for external reporting purposes which includes all the requirements of IFRS plus the continued use of rate regulated accounting by way of reference to US GAAP (section ASC 980). Regulatory assets and liabilities will continue to be recognized for external reporting.
Fortis BC (gas)	**BC**	**See BC Hydro**	**US GAAP** – regulatory assets and liabilities may continue to be recognized.
Fortis BC (electric)	**BC**	**See BC Hydro**	**US GAAP** – regulatory assets and liabilities may continue to be recognized
ATCO Electric	**AB**	As per the Alberta Utilities Commission Rule 026, "*Utilities shall maintain the existing practice of applying to the Commission for approval of any deferral accounts that may be required for the purpose of establishing Regulatory Assets and Liabilities and proposing the mechanism for their disposal.*"	**IFRS –** deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized. Impact of rate regulation disclosed in the notes to the financial statements.

Utility Name	Jurisdiction	Treatment of Regulatory Assets and Liabilities	
		Regulatory Purposes	**External Purposes**
ATCO Gas	**AB**	**See ATCO Electric**	**IFRS** – deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized. Impact of rate regulation disclosed in the notes to the financial statements.
Fortis Alberta	**AB**	**See ATCO Electric**	**US GAAP** – regulatory assets and liabilities may continue to be recognized.
AltaLink	**AB**	**See ATCO Electric**	**IFRS** - deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized. Some previous regulatory assets and liabilities under CGAAP meet the criteria for recognition as financial assets and liabilities under IFRS.
SaskPower	**SK**	Rate regulated accounting not practiced for rate setting purposes.	**IFRS** - deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized
Manitoba Hydro	**MB**	MH is proposing that upon transition to IFRS, financial and regulatory reporting will be aligned.	**IFRS** - deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized.
Hydro One	**ON**	The OEB will continue to use deferral and variance accounts for rate making in the appropriate circumstances.	**US GAAP** – regulatory assets and liabilities may continue to be recognized.

Utility Name	Jurisdiction	Treatment of Regulatory Assets and Liabilities	
		Regulatory Purposes	External Purposes
		The OEB has granted Hydro One permission to use US GAAP as the accounting standard for regulatory purposes and thus, regulatory assets and liabilities may be used for rate setting.	
Enbridge Gas Distribution	**ON**	**See Hydro One**	**US GAAP** – regulatory assets and liabilities may continue to be recognized.
Hydro Québec	**PQ**	MH was not able to obtain information with respect to how regulatory assets and liabilities will be treated for rate setting purposes.	**IFRS -** deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized.
Gaz Métro	**PQ**	**See Hydro Quebec**	**US GAAP -** regulatory assets and liabilities may continue to be recognized.
NB Power	**NB**	MH was not able to obtain information with respect to how regulatory assets and liabilities will be treated for rate setting purposes.	**IFRS -** deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized.
Nova Scotia Power	**NS**	MH was not able to obtain information with respect to how regulatory assets and liabilities will be treated for rate setting purposes.	**US GAAP** – regulatory assets and liabilities may continue to be recognized.

JLM

Utility Name	Jurisdiction	Treatment of Regulatory Assets and Liabilities	
		Regulatory Purposes	**External Purposes**
Newfoundland and Labrador Hydro	**NL**	Certain regulatory accounts are to be maintained for rate setting purposes	**IFRS-** deferral accounts that do not satisfy the criteria for recognition as an asset or liability under IFRS are not recognized.
Newfoundland Power	**NL**	Regulatory assets and liabilities are used for rate setting purposes.	**US GAAP** – regulatory assets and liabilities may continue to be recognized.

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The following table provides a summary of the accounting changes by fiscal year:

SUMMARY OF ACCOUNTING CHANGES - ELECTRIC OPERATIONS
(in thousands of dollars)

	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Reduction to Costs Capitalized					
Stores Overhead	$ 5,100	5,202	5,306	5,412	5,520
Executive Costs	2,000	2,040	2,081	2,122	2,165
Property Taxes on Facilities	2,000	2,040	2,081	2,122	2,165
Interest on Common Assets (Facilities & Equipment)		11,165	11,388	11,616	11,848
General & Administrative Departmental Costs		4,500	4,590	4,682	4,775
Interest on Motor Vehicles		3,780	3,856	3,933	4,011
IT Infrastructure & Related Support				17,100	17,442
Building Depreciation & Operating Costs				9,500	9,690
Technical & Softskills Training					10,450
Service Areas (Management Accounting, HR, Safety, etc.)					8,550
Administrative & Clerical Support Staff					8,550
Division & Department Manager					6,650
Fleet & Stores Administration					1,900
	9,100	28,727	29,302	56,488	93,717
Intangible Assets					
Ineligible for Capitalization	4,080	4,162	4,245	4,330	4,416
Rate Regulated Accounts					
Power Smart Program					31,713
Site Remediation					4,586
Regulatory Costs					1,344
	-	-	-	-	37,643
Pension & Benefits					
Change in Discount Rate			3,445		
Unamortized Past Service Amendments for Retiree Health Spending					(1,647)
Past Service Pension Costs					(521)
	-	-	3,445	-	(2,169)
Reclassifications					
Wire & Telecom Services	3,060	3,121	3,184	3,247	3,312
Funding Payments (Town of Gillam & Frontier School Division)	(5,000)	(5,100)	(5,202)	(5,306)	(5,412)
Operating Expense Recoveries				8,300	8,466
	(1,940)	(1,979)	(2,018)	6,241	6,366
Total	$ 11,240	$ 30,910	$ 34,973	$ 67,059	$139,974

PUB/MH I-42

Reference: 2011 Annual Report Page 78, Accounting Changes/ 2012 Annual Report

Please re-file IFF11-2 Pages 31 and 33 including an additional line items quantifying the net impact of accounting changes reflected in the IFF. Please provide a further detailed schedule on the net amount, including narrative descriptions of each of the accounting changes and cite specific handbook sections.

ANSWER:

Please see the following schedules:

Schedule A presents the net impacts of accounting changes by operating statement line item under CGAAP and IFRS. Narratives referencing the changes are provided following the schedules.

Schedule B presents the net impacts of the accounting changes to Retained Earnings.

Schedules C & D reflect the impact of the accounting changes in the income statement and balance sheet of IFF11-2 respectively.

SCHEDULE A - ACCOUNTING CHANGES - IFF11-2

	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast --> 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
Electric only (in millions of $'s)															
OM&A															
CGAAP Changes															
Intangibles															
DSM	1	1	1	1	1	1	1	1	2	2	2	2	2	2	
Planning Studies	3	2	2	2	2	2	2	2	2	2	2	2	2	3	
IT Application	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total	5	4	4	4	4	4	5	5	5	5	5	5	5	5	1
Overhead Capitalized															
Stores	5	5	5	5	5	6	6	6	6	6	6	6	6	6	2
Admin& General		4	24	24	51	52	53	54	55	56	58	59	60	61	3
Store & Admin General	5	9	29	29	56	58	59	60	61	62	64	65	66	68	
Change in Discount Rate on Pension & Other Benefits				3											4
Subtotal CGAAP Changes	10	13	33	37	61	62	63	65	66	67	68	70	71	73	
IFRS Changes															
DSM						32	29	29	26	22	21	19	19	19	5
Site Remediation						5	5	5	5	5	5	5	5	5	5
Regulatory Costs						1	1	1	1	1	1	2	2	2	5
Pension						(1)	(3)	1	3	4	5	6	7	9	6
Employee Benefits (amortization of RHSA)						(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(0)	6
Admin & General						36	37	37	38	39	40	40	41	42	7
Subtotal IFRS Changes						72	67	72	71	69	72	72	74	76	
Reclassifications															
Wire & Telecom Services	3	3	3	3	3	3	3	3	4	4	4	4	4	4	8
Funding Agreements		(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	9
Operating Expense Recoveries					8	8	9	9	9	9	9	10	10	10	10
Subtotal Reclassifications	3	(2)	(2)	(2)	6	6	6	7	7	7	7	7	7	7	
Total OM&A Accounting Changes	13	11	31	35	67	140	136	143	144	143	147	149	152	156	

SCHEDULE A - ACCOUNTING CHANGES - IFF11-2 cont'd

Electric only (in millions of $'s)	Actual	Actual	Actual	Actual	Forecast -->										
DEPRECIATION & AMORTIZATION EXPENSE	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Ref
CGAAP Changes															
Administrative & General Overhead Capitalized				-	(0)	(1)	(2)	(2)	(3)	(4)	(4)	(5)	(6)	(7)	3
Average Service Life				(35)	(38)	(41)	(43)	(44)	(46)	(49)	(53)	(57)	(65)	(68)	11
Subtotal CGAAP Changes				(35)	(39)	(41)	(44)	(46)	(49)	(52)	(57)	(62)	(70)	(74)	
IFRS Changes															
Administrative & General Overhead Capitalized				-	-	(0)	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	7
Reduction in Amortization of Rate Regulated Assets				-	-	(37)	(39)	(40)	(40)	(39)	(36)	(34)	(33)	(32)	5
Change to Equal Life Group Depreciation method				-	-	32	33	35	36	39	43	44	51	53	12
Removal of Net Salvage from depreciation rates						(55)	(58)	(61)	(64)	(72)	(82)	(85)	(96)	(99)	13
Subtotal IFRS Changes				-	-	(60)	(65)	(68)	(71)	(75)	(80)	(81)	(85)	(86)	
Total Depreciation Accounting Changes				(35)	(39)	(101)	(109)	(114)	(120)	(128)	(137)	(143)	(155)	(160)	
FINANCE EXPENSE															
CGAAP Changes				0	0	0	0	0	1	1	1	1	1	1	
IFRS Changes				-	-	2	2	2	2	1	1	0	0	0	
Total Finance Expense Accounting Changes				0	0	3	3	2	2	2	2	1	1	1	14
CAPITAL TAX EXPENSE															
CGAAP Changes				0	0	0	0	0	1	1	1	1	1	1	
IFRS Changes				-	-	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	
Total Capital Tax Expense Accounting Changes				0	0	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	0	14

SCHEDULE B - ACCOUNTING CHANGES IMPACT TO RETAINED EARNINGS - IFF11-2

Electric only (in millions of $'s) **IMPACT TO RETAINED EARNINGS**	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast --> 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
CGAAP Changes															
Retrospective adjustment for intangible Assets		(35)													(35)
Annual change to OM&A	(10)	(13)	(33)	(37)	(61)	(62)	(63)	(65)	(66)	(67)	(68)	(70)	(71)	(73)	(759)
Annual change to Depreciation & Amortization	-	-	-	35	39	41	44	46	49	52	57	62	70	74	570
Annual change to Finance & Capital Tax Changes	-	-	-	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(13)
Total	(10)	(48)	(33)	(2)	(23)	(21)	(20)	(20)	(18)	(16)	(13)	(10)	(3)	(1)	(236)
IFRS Changes															
Annual change to OM&A	-	-	-	-	-	(72)	(67)	(72)	(71)	(69)	(72)	(72)	(74)	(76)	(644)
Annual change to Depreciation & Amortization	-	-	-	-	-	60	65	68	71	75	80	81	85	86	672
Annual change to Finance & Capital Tax Changes	-	-	-	-	-	(1)	(0)	0	(0)	0	0	1	1	1	2
Write Offs to:															-
Power Smart Programs						(183)									(183)
Site Remediation						(36)									(36)
Acquisition (Centra & Manitoba Hydro)						(20)									(20)
Regulatory Costs						(2)									(2)
Administrative Overhead						(36)									(36)
Removal of Net Salvage Depreciation						53									53
Change to Equal Life Group Depreciation						(31)									(31)
Employee Benefits						(22)									(22)
Total	-	-	-	-	-	(288)	(2)	(4)	(0)	6	8	11	12	10	(247)
Total Annual Impact to Retained Earnings	(10)	(48)	(33)	(2)	(23)	(310)	(22)	(23)	(19)	(10)	(5)	1	9	9	(483)

Reference	Description	Accounting Handbook Reference
1	The OM&A adjustments for intangible assets under CGAAP reflect a change (new section 3064 Goodwill and Intangible Assets) in the Canadian accounting standards for Goodwill and Intangible assets that was effective for MH April 1, 2009. The new standard was harmonized with IFRS and required research and promotional costs to be expensed as incurred with retrospective application. Approximately $35 million was adjusted to retained earnings in fiscal 2009/10 for research and promotional costs included in opening intangible asset balances. Effective April 1, 2009 and forward, research and promotional costs associated with intangible assets are expensed as incurred	**CGAAP – Section 3064 Goodwill and Intangible Assets** .37 No intangible asset arising from research (or from the research phase of an internal project) should be recognized. Expenditure on research (or on the research phase of an internal project) should be recognized as an expense when it is incurred. [OCT. 2008] .52 In some cases, expenditure is incurred to provide future economic benefits to an entity, but no intangible asset or other asset is acquired or created that can be recognized,…,Other examples of expenditure that is recognized as an expense when it is incurred include expenditure on: (a) start-up activities (i.e., start-up costs), (b) training activities. (c) advertising and promotional activities.
2	The OM&A adjustments for stores reflect a change in the accounting standards for costs eligible to be included in the cost of inventories. The CGAAP section 3031 Inventories is converged with IFRS and was effective for MH April 1, 2007. As per Section 3031, storage related overhead charges are no longer permitted in the cost of material in inventory.	**CGAAP –Section 3031 Inventories** .16 Examples of costs excluded from the cost of inventories and recognized as expenses in the period in which they are incurred are: (a) abnormal amounts of wasted materials, labour or other production costs; (b) storage costs, unless those costs are necessary in the production process before a further production stage; (c) administrative overheads that do not contribute to bringing inventories to their present location and condition; and
3	The reduction in administrative and general overhead capitalized reflects adjustments made under CGAAP to become more consistent with other Canadian utilities. The adjustments result in the following: • an annual increase in operating and administrative expense;	**CGAAP – Section 3061 Property, plant & equipment:** .20 The cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.

	• reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	These changes were identified through discussions with other Canadian utilities.
4	The increase in the pension and employee benefits cost is a result of a reduction in the 2011/12 discount rate and the corresponding increase in current service cost for employee benefits.	**CGAAP – Section 3461 Employee Future Benefits:** .50 " For a defined benefit plan, the discount rate used to determine the accrued benefit obligation should be an interest rate determined by reference to: (a) market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments; or (b) the interest rate inherent in the amount at which the accrued benefit obligation could be settled. [JAN. 2000] .054 The discount rate is re-evaluated at each measurement date. When long-term interest rates rise or decline, the discount rate changes in a similar manner.
5	IFF 11-2 assumes rate-regulated accounting is not permitted under IFRS and thus, rate-regulated accounting will be eliminated upon transition. The impacts of this assumption are as follows • upon transition to IFRS, a one-time adjustment to retained earnings will be made for unamortized rate-regulated account balances; • future expenditures on these items will be expensed as incurred resulting in an annual increase to operating and administrative expense; and • a reduction to depreciation and amortization for previously deferred regulatory accounts.	Unlike CGAAP and US GAAP, there is no specific IFRS standard that permits rate-regulated accounting. Generally, the application of the existing IFRS framework has not resulted in the recognition of regulatory assets and liabilities.

6	Overall, changes to the accounting for pension and benefits results in an increase in pension and benefit costs upon transition to IFRS. The primary pension accounting changes include: • upon transition, unamortized pension gains and losses will be adjusted to accumulated other comprehensive income; • the elimination of "corridor" determined amortization for unrealized pension experience gains and losses as IFRS requires annual gains and losses to be recognized in Other Comprehensive Income; and • the use of the pension discount rate for recording expected returns on plan assets as opposed to the expected market interest rate of return as per CGAAP. **Employee benefits:** The primary employee benefit related changes include: • upon transition, unamortized past service adjustments will be adjusted to retained earnings; and • future annual benefits expense will be higher for the recognition of benefits attributed to unvested employees for benefits such as sick leave and severance. Such unvested benefits were not recognized under CGAAP, but are required to be recognized under IFRS.	**IFRS – IAS 19 Employee Benefits:** .120 An entity shall recognise the components of defined benefit cost, except to the extent that another IFRS requires or permits their inclusion in the cost of an asset, as follows: (a) service cost in profit or loss;…, (c) re-measurements of the net defined benefit liability (asset) in other comprehensive income. .125 Interest income on plan assets is a component of the return on plan assets, and is determined by multiplying the fair value of the plan assets by the discount rate specified in paragraph 83, both as determined at the start of the annual reporting period, taking account of any changes in the plan assets held during the period as a result of contributions and benefit payments. .103 An entity shall recognise past service cost as an expense at the earlier of the following dates: (a) when the plan amendment or curtailment occurs; and (b) when the entity recognises related restructuring costs or termination benefits (see paragraph 165). **Employee Benefits:** .15 Accumulating paid absences are those that are carried forward and can be used in future periods if the current period's entitlement is not used in full. ,…, An obligation arises as employees render service that increases their entitlement to future paid absences. The obligation exists, and is recognised, even if the paid absences are non-vesting, although the possibility that employees may leave before they use an accumulated non-vesting entitlement affects the measurement of that obligation.
7	The reduction in administrative and general overhead capitalized reflects adjustments to comply with IFRS upon transition. IFRS does not permit the capitalization	**IFRS - IAS 16 Property, plant & equipment:** .19 Examples of costs that are not costs of an item of property, plant

	of general administrative and overhead costs. The adjustments result in the following: • an annual increase in operating and administrative expense; • reductions in plant asset values for amounts no longer capitalized; and • reductions in depreciation expense as a result of reduced asset values.	and equipment are:,… (d) administration and other general overhead costs.
8	The increase to OM&A resulting from Wire and Telecom services reflects a change in MH's financial reporting where the operations pertaining to Wire and Telecom services are now reported under Manitoba Hydro International.	**No accounting standard reference applies**
9	The reduction to OM&A resulting from Funding payments (Town of Gillam & Frontier School Division) reflect the re-classification of these expenditures from OM&A to Capital & Other taxes as this more appropriately reflects the nature of these expenditures.	**CGAAP – Section 1000 Financial Statement Concepts** 21 For the information provided in financial statements to be useful, it must be reliable. Information is reliable when it is in agreement with the actual underlying transactions and events, … (a) …Thus, transactions and events are accounted for and presented in a manner that conveys their substance rather than necessarily their legal or other form.
10	The adjustments for operating expense recoveries are to comply with the financial reporting requirements of IFRS. Revenues that were once netted against operating costs for financial reporting will be reported as revenue in the future as IFRS generally does not permit netting of revenues and expenses.	**IFRS - IAS 1 Presentation of Financial Statements:** . 32 - An entity shall not offset assets and liabilities or income and expenses, unless required or permitted by an IFRS.
11	The net result of the depreciation study under CGAAP and the average service life approach is an overall reduction in annual depreciation expense for MH due to changes in the service lives for certain asset groups. This change is required to be implemented under Canadian	**CGAAP – 3061 Property, plant & equipment:** .28 Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property, plant and equipment with a limited life and its use by the enterprise.

	GAAP.	.33 The amortization method and estimates of the life and useful life of an item of property, plant and equipment should be reviewed on a regular basis. [DEC. 1990 *]
12	Upon adoption of IFRS, MH will be moving from the Average Service Life method of depreciation to the Equal Life Group method; increasing annual depreciation expense.	**IFRS - IAS 16 Property, plant & equipment:** The key IFRS reference supporting the move to the ELG method is: 68 The gain or loss arising from the de-recognition of an item of property, plant and equipment shall be included in profit or loss when the item is de-recognised. Gains shall not be classified as revenue.
13	Upon adoption of IFRS, MH will be removing the impact of net salvage from depreciation rates; decreasing annual depreciation expense.	-The Inclusion of net salvage in depreciation rates is a regulatory practice applied under CGAAP by Canadian utilities. Given that IFRS does not recognize rate regulated activities, the practice of including negative salvage in depreciation rates will be discontinued upon transition to IFRS. No IFRS standard reference is available for rate-regulated accounting.
14	The changes to finance expense and capital and other taxes reflect the cumulative impacts of changes 1 – 12 as identified in this chart.	**Please see descriptions as provided in 1- 12.**

SCHEDULE C - ACCOUNTING CHANGES - IMPACT ON IFF11-2

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB-MH I-42 - Net Impact of Accounting Changes
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1,186	1,290	1,294	1,306	1,313	1,330	1,350	1,361	1,382	1,403	1,422
additional*	0	45	106	156	208	265	325	387	455	527	603
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	7	8	8	8	8	8	8	9	9	9
CGAAP Accounting Changes:	-	8	8	9	9	9	9	9	10	10	10
	1,556	1,693	1,778	1,873	2,007	2,114	2,224	2,320	2,466	2,769	2,957
EXPENSES											
Operating and Administrative	363	380	392	406	404	410	428	433	446	459	466
CGAAP Accounting Changes:	37	61	62	63	65	66	67	68	70	71	73
Reclassifications:	(2)	6	6	6	7	7	7	7	7	7	7
IFRS Accounting Changes:			72	67	72	71	69	72	72	74	76
Finance Expense	385	440	450	502	535	567	638	761	802	1,146	1,108
CGAAP Accounting Changes:	-	-	-	-	-	1	1	1	1	1	1
IFRS Accounting Changes:	-	-	2	2	2	2	1	1	-	-	-
Depreciation and Amortization	388	440	455	467	489	507	549	605	626	705	736
CGAAP Accounting Changes:	(35)	(39)	(41)	(44)	(46)	(49)	(52)	(57)	(62)	(70)	(74)
IFRS Accounting Changes:	-	-	(60)	(65)	(68)	(71)	(75)	(80)	(81)	(85)	(86)
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	77	81	89	94	103	112	120	126	135	122	128
CGAAP Accounting Changes:	-	-	-	-	-	1	1	1	1	1	1
Reclassifications:	5	5	5	6	6	6	6	6	6	6	6
IFRS Accounting Changes:	-	-	(2)	(2)	(2)	(2)	(1)	(1)	(1)	(1)	(1)
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1,492	1,671	1,709	1,810	1,881	1,953	2,101	2,300	2,393	2,823	2,833
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	68	62	124	159	121	18	70	(57)	113

SCHEDULE D - ACCOUNTING CHANGES - IMPACT ON IFF11-2

ELECTRIC OPERATIONS (MH11-2)
PROJECTED BALANCE SHEET
PUB-MH I-42 - Net Impact of Accounting Changes
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
ASSETS											
Plant in Service	13,880	15,353	15,958	16,816	17,838	18,520	22,043	22,636	26,358	29,219	29,690
CGAAP Accounting Changes pre 2012:	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)	(56)
CGAAP Accounting changes	(29)	(85)	(143)	(202)	(262)	(323)	(385)	(449)	(514)	(580)	(648)
IFRS Accounting Changes			(36)	(73)	(110)	(148)	(187)	(227)	(267)	(308)	(350)
Accumulated Depreciation	(4,952)	(5,340)	(5,756)	(6,195)	(6,670)	(7,156)	(7,710)	(8,321)	(8,953)	(9,663)	(10,405)
CGAAP Accounting Changes:	35	74	115	159	205	254	306	363	425	495	569
IFRS Accounting Changes:	-	-	60	125	193	264	339	419	500	585	671
Net Plant in Service	8,878	9,946	10,142	10,574	11,138	11,355	14,350	14,365	17,493	19,692	19,471
Construction in Progress	2,443	2,196	3,149	3,997	5,014	6,410	5,346	6,447	4,558	3,595	4,964
Current and Other Assets	1,909	1,868	1,697	1,742	1,929	2,110	2,357	2,149	2,321	2,540	2,418
CGAAP Accounting Changes pre 2012:	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
IFRS Accounting Changes:	-	-	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)
Goodwill and Intangible Assets	181	179	162	149	136	126	117	109	103	97	93
Regulated Assets	240	241	241	233	225	214	200	188	175	163	154
IFRS Accounting Changes:	-	-	(241)	(233)	(225)	(214)	(200)	(188)	(175)	(163)	(154)
	13,648	14,426	14,780	16,092	17,846	19,631	21,800	22,701	24,105	25,555	26,576
LIABILITIES AND EQUITY											
Long-Term Debt	9,253	9,469	10,909	12,169	13,789	15,261	17,025	18,518	19,480	20,990	22,434
Current and Other Liabilities	1,351	1,916	1,386	1,502	1,560	1,727	2,031	1,430	1,812	1,807	1,285
IFRS Accounting Changes:	-	-	20	17	14	10	5	2	(1)	7	4
Contributions in Aid of Construction	317	328	341	348	355	365	376	386	396	407	418
Retained Earnings	2,485	2,527	2,628	2,712	2,860	3,037	3,168	3,191	3,261	3,194	3,297
CGAAP Accounting Changes pre 2012:	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)	(91)
CGAAP Accounting Changes:	(2)	(25)	(46)	(66)	(86)	(104)	(120)	(133)	(143)	(146)	(147)
IFRS Accounting Changes:	-	-	(288)	(290)	(294)	(294)	(288)	(280)	(270)	(257)	(245)
Accumulated Other Comprehensive Income	335	302	288	153	106	88	61	45	29	11	(12)
IFRS Accounting Changes:	-	-	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)	(367)
	13,648	14,426	14,780	16,092	17,846	19,631	21,800	22,701	24,105	25,555	26,576

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PUB/MH I-66

Reference: Tab 5 Page 18 of 36, Schedule 5.6.0 Finance Expense

a) Please re-file schedule 5.6.0 including the years 2003/04 through 2008/09.

ANSWER:

Please see the attached schedule.

MANITOBA HYDRO
FINANCE EXPENSE

Schedule 5.6.0
(000's)

	2007/08 Actual	2008/09 Actual	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast
Interest on Short & Long-Term Debt							
Gross Interest	$ 448,106	$ 490,046	$ 447,346	$ 476,448	$ 492,561	$ 513,478	$ 550,766
Provincial Guarantee Fee	69,865	70,360	72,274	76,697	82,182	90,966	99,723
Amortization of (Premiums), Discounts, and Transaction Costs	(11,054)	(12,322)	(11,262)	2,872	255	396	430
Intercompany Interest Receivable	(19,774)	(18,182)	(15,737)	(16,224)	(17,318)	(15,072)	(15,404)
Total Interest on Short & Long-Term Debt	487,143	529,903	492,621	539,794	557,680	589,768	635,515
Interest Earned on Sinking Fund	(30,180)	(24,920)	(23,702)	(17,068)	(9,828)	(10,553)	(9,711)
Interest Allocated to Construction	(60,015)	(74,493)	(98,121)	(135,517)	(167,398)	(144,805)	(178,085)
Corporate Allocation	(17,483)	(17,543)	(17,896)	(19,112)	(19,174)	(19,128)	(19,128)
Other Amortization	21,331	20,116	20,365	19,946	23,765	24,359	23,053
Total Finance Expense	$ 400,796	$ 433,063	$ 373,267	$ 388,043	$ 385,044	$ 439,641	$ 451,643

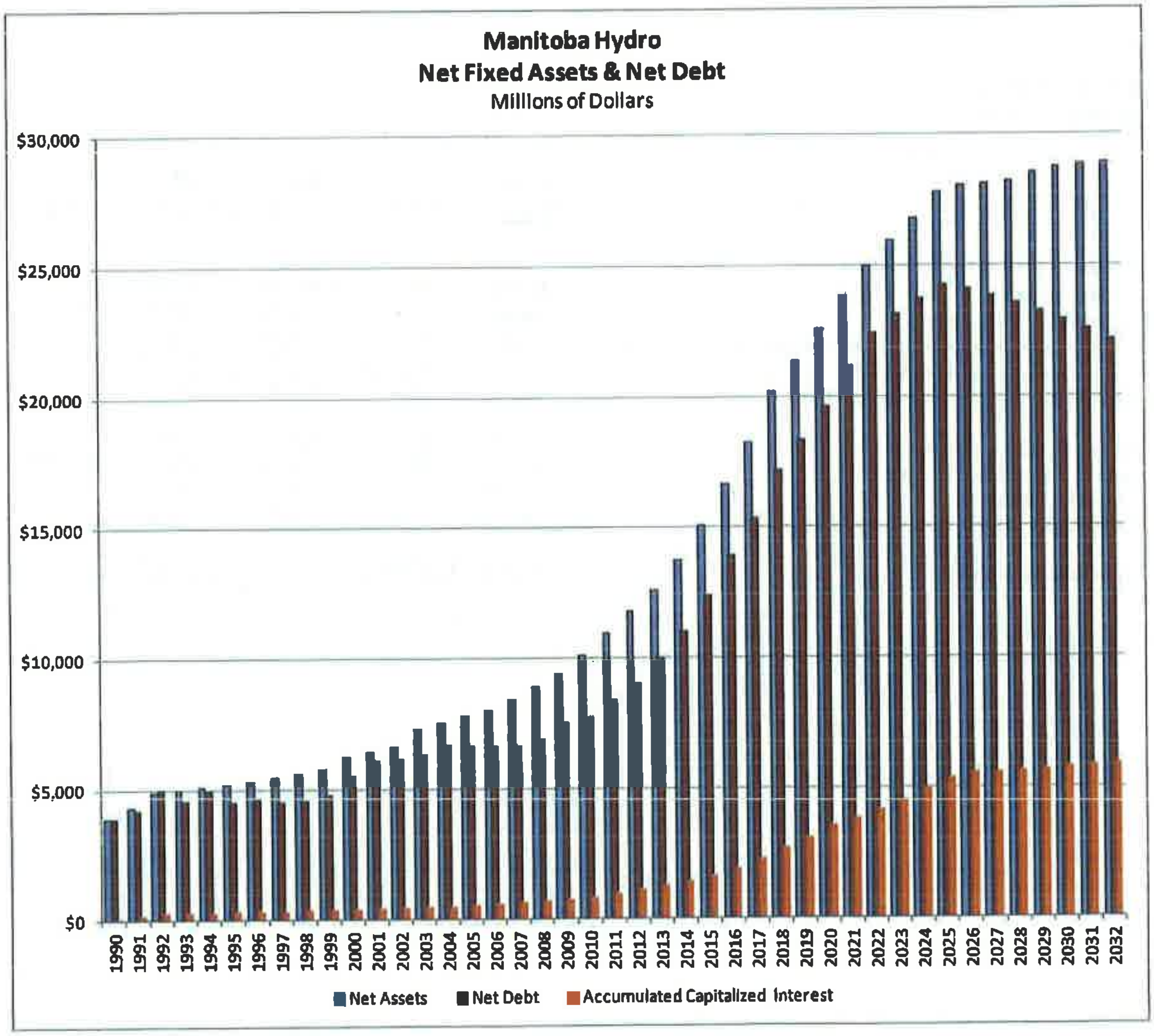
PUB/MH I-101

Reference: Appendix 6.2 Debt Management Strategy 2011 & 2012 GRA

a) Please refile an updated response to PUB/MH I-69 (a) based on IFF11-2 including an updated the graph of Net Fixed Assets & Net Debt for the years 1990 through 2032 identifying the level of accumulated capitalized interest in each year. Please provide a table of corresponding data points.

ANSWER:

The values for the years 1990 to 2012 are based on actuals, and 2013 to 2032 values are based on the forecast IFF11-2 (Consolidated Operations).



The chart illustrates the growth in net fixed assets and net long term debt that has occurred over the past 20 years, as well as the projected growth to 2032. While net debt is expected to grow to approximately $22.2 billion as at March 31, 2032, the corresponding investment in generation, transmission, distribution and other assets is expected to grow to a net book value of approximately $28.9 billion at March 31, 2032.

A table of corresponding data points is as follows:

Year Ending	Net Assets	Capitalized Interest	Accumulated Capitalized Interest	Net Debt
1990	3,882	97	97	3,889
1991	4,267	110	207	4,199
1992	4,857	72	279	4,972
1993	4,983	32	312	4,533
1994	5,067	16	328	4,948
1995	5,170	15	342	4,508
1996	5,310	19	361	4,685
1997	5,464	16	377	4,493
1998	5,608	20	396	4,559
1999	5,774	20	416	4,772
2000	6,235	15	431	5,488
2001	6,428	16	447	6,114
2002	6,626	26	473	6,146
2003	7,305	28	501	6,320
2004	7,536	32	532	6,675
2005	7,776	33	565	6,642
2006	8,010	34	600	6,614
2007	8,415	47	647	6,597
2008	8,912	60	707	6,870
2009	9,382	56	763	7,521
2010	10,128	68	831	7,716
2011	10,954	138	969	8,365
2012	11,797	170	1,139	9,010
2013	12,608	142	1,280	9,984
2014	13,771	178	1,458	11,019
2015	15,056	221	1,679	12,354
2016	16,644	280	1,960	13,905
2017	18,263	365	2,325	15,331
2018	20,204	403	2,727	17,176
2019	21,331	387	3,114	18,358
2020	22,581	447	3,561	19,610
2021	23,830	285	3,846	21,146
2022	24,991	291	4,137	22,392
2023	25,959	378	4,515	23,161
2024	26,816	452	4,967	23,715
2025	27,816	403	5,370	24,255
2026	28,062	203	5,573	24,126
2027	28,113	31	5,604	23,850
2028	28,244	45	5,650	23,566
2029	28,531	68	5,717	23,270
2030	28,761	95	5,812	22,966
2031	28,882	45	5,857	22,562
2032	28,920	47	5,904	22,172

PUB/MH I-101

Reference: Appendix 6.2 Debt Management Strategy 2011 & 2012 GRA

b) Please refile and updated response to PUB/MH I-69 (b) provide a corresponding table of Net Assets, Net Debt, Retained Earnings, Debt to Equity ratio, Capital Coverage ratio, and Interest Coverage ratio of the corresponding year.

ANSWER:

Please see the attached schedule.

Year Ending	Net Assets *Millions of dollars*	Net Debt *Millions of dollars*	Retained Earnings *Millions of dollars*	D/E Ratio	I/C Ratio	C/C Ratio
1990	3,882	3,889	117	95:05	1.07	
1991	4,267	4,199	165	94:06	1.13	
1992	4,857	4,972	183	94:06	1.04	
1993	4,983	4,533	159	95:05	0.95	
1994	5,067	4,948	228	93:07	1.16	
1995	5,170	4,508	284	92:08	1.13	1.00
1996	5,310	4,685	354	91:09	1.16	1.00
1997	5,464	4,493	455	88:12	1.23	1.10
1998	5,608	4,559	566	86:14	1.25	1.13
1999	5,774	4,772	666	84:16	1.23	1.22
2000	6,235	5,488	818	83:17	1.35	1.28
2001	6,428	6,114	1,088	80:20	1.62	1.18
2002	6,626	6,146	1,302	77:23	1.42	1.67
2003	7,305	6,320	1,170	80:20	1.14	1.10
2004	7,536	6,675	734	87:13	0.17	(0.32)
2005	7,776	6,642	870	85:15	1.25	1.20
2006	8,010	6,614	1,285	81:19	1.77	2.28
2007	8,415	6,597	1,407	80:20	1.23	1.10
2008	8,912	6,870	1,822	73:27	1.69	1.62
2009	9,382	7,521	2,076	77:23	1.49	1.77
2010	10,128	7,716	2,239	73:27	1.32	1.30
2011	10,954	8,365	2,389	73:27	1.27	1.25
2012	11,797	9,010	2,450	74:26	1.10	1.13
2013	12,608	9,984	2,483	76:24	1.05	1.19
2014	13,771	11,019	2,203	82:18	1.12	1.18
2015	15,056	12,354	2,277	84:16	1.10	1.22
2016	16,644	13,905	2,414	85:15	1.16	1.47
2017	18,263	15,331	2,587	85:15	1.18	1.58
2018	20,204	17,176	2,722	86:14	1.12	1.51
2019	21,331	18,358	2,754	87:13	1.03	1.32
2020	22,581	19,610	2,839	87:13	1.07	1.49
2021	23,830	21,146	2,796	88:12	0.97	1.45
2022	24,991	22,392	2,924	88:12	1.09	1.85
2023	25,959	23,161	3,150	88:12	1.15	1.92
2024	26,816	23,715	3,455	87:13	1.19	1.97
2025	27,816	24,255	3,872	86:14	1.26	2.02
2026	28,062	24,126	4,338	84:16	1.28	2.32
2027	28,113	23,850	4,768	82:18	1.26	2.28
2028	28,244	23,566	5,292	80:20	1.33	2.52
2029	28,531	23,270	5,898	78:22	1.38	2.54
2030	28,761	22,966	6,607	76:24	1.45	2.60
2031	28,882	22,562	7,350	73:27	1.48	3.23
2032	28,920	22,172	8,245	70:30	1.62	2.92

PUB/MH II-2(a)

Financial History

	Debt/Equity Ratio	Capital Coverage Ratio	Interest Coverage Ratio	Total MH Assets	MH Net Income	Total MH Debt	MH Retained Earnings	DBRS Bond Rating **	Total Province of MB Debt	Total MH Debt to Total MB Debt
2012	74:26	1.13	1.10	13,791	61	9,382	2,450	A (high)	28,698	32.7%
2011	73:27	1.25	1.27	12,882	150	8,647	2,389	A (high)	25,617	33.8%
2010	73:27	1.30	1.32	12,437	163	8,538	2,239	A (high)	24,431	34.9%
2009	77:23	1.77	1.48	11,547	266	8,187	2,076	A (high)	22,727	36.0%
2008	73:27	1.62	1.69	11,766	346	7,571	1,822	A (high)	22,056	34.3%
2007	80:20	1.10	1.23	10,922	122	7,227	1,407	A (high)	20,476	35.3%
2006	81:19	2.28	1.77	10,482	415	7,169	1,285	A (high)	19,828	36.2%
2005	85:15	1.20	1.25	9,952	136	7,204	870	A (high)	19,410	37.1%
2004	87:13	(0.32)	0.17	9,903	(436)	7,390	734	A (high)	18,206	40.6%
2003	80:20	1.10	1.14	10,234	71	7,268	1,170	A (high)	17,810	40.8%
2002	77:23	1.67	1.42	10,405	214	7,661	1,302	A	20,682	37.0%
2001	80:20	1.18	1.62	9,966	270	7,464	1,088	A	20,459	36.5%
2000	83:17	1.28	1.35	8,692	152	6,770	818	A	19,878	34.1%
1999	84:16	1.22	1.23	7,866	100	5,883	666	A	18,278	32.2%
1998	86:14	1.13	1.25	7,617	111	5,548	566	A	17,378	31.9%
1997	88:12	1.12	1.23	7,133	101	5,175	455	A	16,886	30.6%
1996	91:09	1.00	1.16	6,737	70	5,284	354	A	16,763	31.5%
1995	92:08	1.00	1.13	6,449	56	5,034	284	A	16,481	30.5%
1994	93:07	n/a	1.16	6,543	70	5,406	228	A	15,670	34.5%
1993*	95:05	n/a	0.95	6,025	(24)	4,971	159	A	14,127	35.2%
1992	94:06	n/a	1.04	6,505	18	5,441	183	A	12,776	42.6%

* The first unit of the Limestone Generation Station went into service in September 1990 and all ten units were operational by September 1992.

** The DBRS long term credit rating for the period from 1992-2012 is the same for both the Manitoba Hydro-Electric Board and the Province of Manitoba.

PUB/MH II-42

IFF11-2 +1% INTEREST RATE SENSITIVITY COMPARED TO BASE CASE
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Total
New Long-Term Debt Issued:												
IFF11	200	1,000	1,600	1,400	2,000	2,000	2,600	1,800	1,800	2,000	1,800	18,200
Interest +1%	200	1,000	1,600	1,600	2,000	2,000	2,800	2,000	1,800	2,200	2,000	19,200
New Long-Term Debt Interest Rate:												
IFF11	3.75%	3.70%	4.05%	5.40%	5.90%	6.20%	6.40%	6.40%	6.40%	6.40%	6.40%	
Interest +1%	3.75%	4.70%	5.05%	6.40%	6.90%	7.20%	7.40%	7.40%	7.40%	7.40%	7.40%	
Change in Net Finance Expense:												
Gross Interest on New Long-Term Debt	0	3	18	36	58	85	114	145	179	227	243	1,108
Gross Interest on Short-Term Debt	0	1	1	2	0	0	(0)	2	0	(0)	1	7
Gross Interest on Existing Floating Rate Debt	0	10	14	12	11	8	6	4	4	4	4	76
Provincial Guarantee Fee	0	0	0	0	1	1	2	4	5	7	9	29
Interest on Assets Under Construction	0	(21)	(30)	(38)	(49)	(64)	(71)	(68)	(79)	(45)	(55)	(521)
Interest Income	0	(1)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(7)
Total Change in Net Finance Expense	0	(7)	3	11	21	29	51	86	108	191	199	693
Cumulative Change in Net Finance Expense	0	(7)	(4)	8	28	57	108	194	302	494	693	
Depreciation and Amortization	0	0	0	0	1	1	2	3	3	6	6	21
Capital and Other Taxes	0	0	0	0	1	1	1	2	2	1	2	10
Net Income	(0)	7	(4)	(12)	(22)	(31)	(54)	(90)	(113)	(198)	(206)	(724)
Retained Earnings	(0)	7	3	(9)	(30)	(61)	(115)	(205)	(319)	(517)	(724)	

PUB/MH II-42

IFF11-2 -1% INTEREST RATE SENSITIVITY COMPARED TO BASE CASE
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	10-Year Total
New Long-Term Debt Issued:												
IFF11	200	1,000	1,600	1,400	2,000	2,000	2,600	1,800	1,800	2,000	1,800	18,200
Interest -1%	200	1,000	1,600	1,400	1,800	2,000	2,600	1,600	1,400	2,000	1,400	17,000
New Long-Term Debt Interest Rate:												
IFF11	3.75%	3.70%	4.05%	5.40%	5.90%	6.20%	6.40%	6.40%	6.40%	6.40%	6.40%	
Interest -1%	3.75%	2.70%	3.05%	4.40%	4.90%	5.20%	5.40%	5.40%	5.40%	5.40%	5.40%	
Change in Net Finance Expense:												
Gross Interest on New Long-Term Debt	0	(4)	(18)	(35)	(57)	(80)	(104)	(138)	(166)	(208)	(218)	(1,029)
Gross Interest on Short-Term Debt	0	(1)	(1)	(1)	(0)	(1)	(2)	(0)	(1)	(1)	(1)	(10)
Gross Interest on Existing Floating Rate Debt	0	(10)	(14)	(12)	(11)	(8)	(6)	(4)	(4)	(4)	(4)	(76)
Provincial Guarantee Fee	0	0	(0)	(0)	(1)	(1)	(2)	(3)	(5)	(6)	(8)	(27)
Interest on Assets Under Construction	(0)	21	29	37	47	62	68	63	74	42	52	495
Interest Income	0	1	0	0	0	0	1	1	1	1	1	7
Total Change in Net Finance Expense	(0)	6	(4)	(12)	(22)	(27)	(47)	(81)	(100)	(176)	(178)	(641)
Cumulative Change in Net Finance Expense	(0)	6	2	(9)	(32)	(59)	(105)	(187)	(287)	(463)	(641)	
Depreciation and Amortization	0	(0)	(0)	(0)	(1)	(1)	(2)	(3)	(3)	(5)	(6)	(21)
Capital and Other Taxes	0	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(1)	(1)	(9)
Net Income	0	(6)	4	13	23	29	49	86	105	183	185	671
Retained Earnings	0	(6)	(2)	11	34	63	112	198	303	486	671	

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PUB/MH I-23

Reference: IFF11-2 – Capital Coverage Ratio

Please file an updated IFF11-2 scenario to meet a capital coverage ratio of 1.0 in each year throughout the 20 year forecast with financial ratios and annual impact on rate increase requests assuming all major capital costs are financed by debt. Any reduced revenue requirement should be reflected in the additional revenue line. Please provide all assumptions.

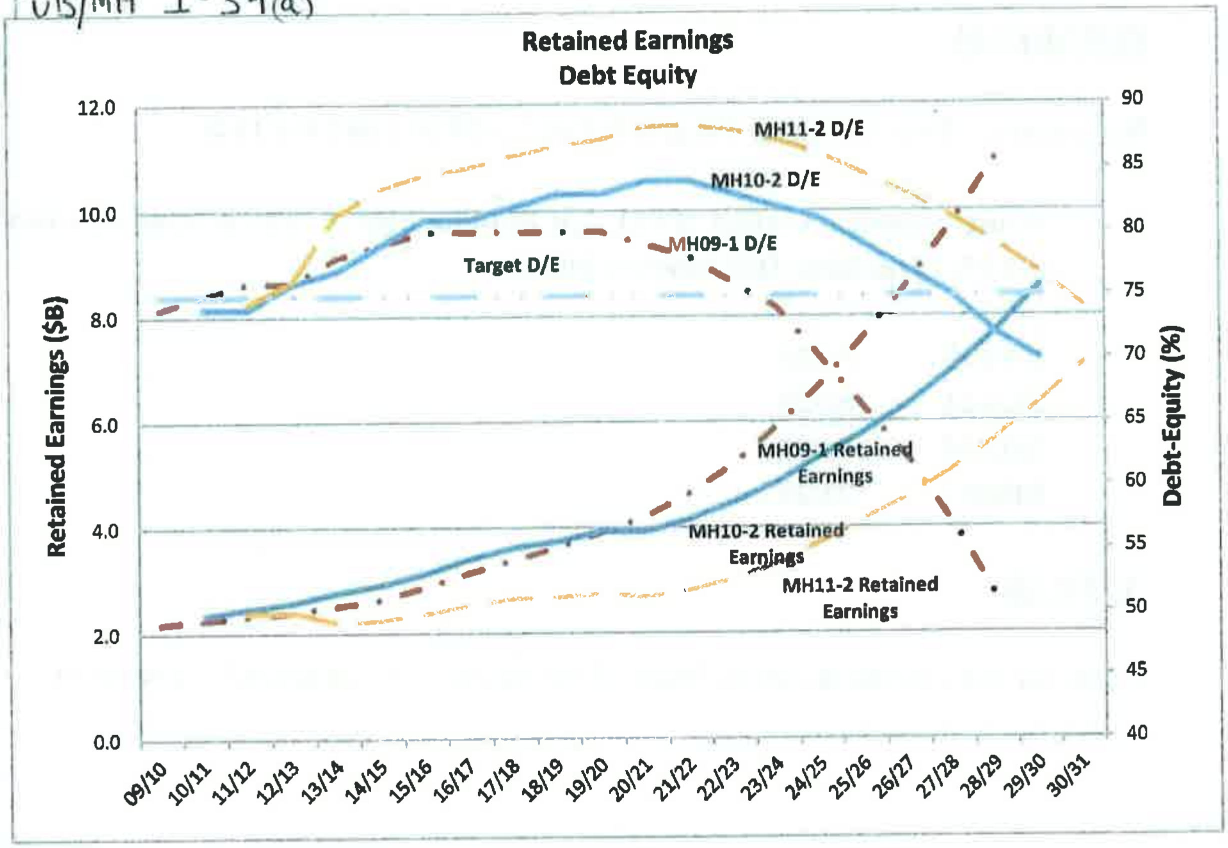
ANSWER:

Please see the following projected financial statements for the requested rate scenario.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
Rates Required From 2013/14 And On To Maintain 1.0 Capital Coverage Ratio
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	60	97	66	83	176	316	325	440	348
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 732	1 814	1 865	1 932	2 074	2 248	2 336	2 681	2 702
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	452	509	547	593	676	812	862	1 219	1 196
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 709	1 815	1 891	1 975	2 137	2 349	2 452	2 895	2 921
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	22	(2)	(29)	(45)	(65)	(103)	(119)	(216)	(229)
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	0.10%	2.69%	-2.23%	1.16%	6.40%	8.97%	0.29%	6.33%	-5.22%
Cumulative Percent Increase	0.00%	4.50%	4.60%	7.42%	5.02%	6.24%	13.03%	23.18%	23.53%	31.35%	24.50%
Financial Ratios											
Equity	26%	24%	18%	16%	14%	12%	11%	10%	8%	7%	6%
Interest Coverage	1.12	1.03	1.03	1.00	0.97	0.95	0.94	0.91	0.91	0.86	0.85
Capital Coverage	1.04	1.07	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

PUB/MH I-34(a)


Retained Earnings
Debt Equity
MH11-2 D/E
MH10-2 D/E
MH09-1 D/E
Target D/E
MH09-1 Retained Earnings
MH10-2 Retained Earnings
MH11-2 Retained Earnings
Retained Earnings ($B)
Debt-Equity (%)
12.0
10.0
8.0
6.0
4.0
2.0
0.0
90
85
80
75
70
65
60
55
50
45
40
09/10
10/11
11/12
12/13
13/14
14/15
15/16
16/17
17/18
18/19
19/20
20/21
21/22
22/23
23/24
24/25
25/26
26/27
27/28
28/29
29/30
30/31

PUB/MH I-34

Reference: Debt to Equity Targets IFF09-1, IFF10-2 and IFF11-2

c) Please provide a revised IFF11 that includes higher annual equal rate increases (>3.5%) to achieve D/E ratios as follows:

2014/15	**80:20**
2020/21	**80/20**
2025/26	**80:20**
2030/31	**75:25**

ANSWER:

Please see the attached projected financial statements for the requested rate scenario.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1 186	1 290	1 294	1 306	1 313	1 330	1 350	1 361	1 382	1 403	1 422
additional*	0	45	258	493	496	503	512	517	526	535	523
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1 556	1 693	1 931	2 210	2 295	2 353	2 410	2 450	2 537	2 776	2 876
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	448	488	499	511	561	668	693	1 026	982
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1 492	1 672	1 705	1 794	1 843	1 893	2 022	2 205	2 283	2 702	2 706
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	225	415	450	457	386	243	251	71	160
Other Comprehensive Income	(18)	(33)	(15)	(142)	(53)	(18)	(27)	(15)	(16)	(18)	(22)
Comprehensive Income	46	(14)	210	272	397	438	359	227	235	53	137
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	14.80%	14.80%	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	-0.99%
Cumulative Percent Increase	0.00%	4.50%	19.97%	37.73%	37.79%	37.86%	37.93%	37.99%	38.06%	38.13%	36.76%
Financial Ratios											
Equity	26%	24%	20%	20%	21%	21%	21%	21%	21%	20%	20%
Interest Coverage	1.12	1.03	1.36	1.58	1.58	1.52	1.40	1.23	1.22	1.05	1.13
Capital Coverage	1.04	1.07	1.51	2.06	2.30	2.33	2.17	1.87	1.93	1.78	2.00

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
PUB/MH I-34 (C) - Achieve 80:20 DE in 2014/15, 2020/21, 2025/26, and 75:25 in 2030/31
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers										
at approved rates	1 441	1 460	1 479	1 498	1 521	1 541	1 562	1 582	1 602	1 622
additional*	510	497	484	471	554	641	734	832	936	999
Extraprovincial	931	946	1 124	1 408	1 526	1 544	1 539	1 544	1 565	1 574
Other	19	20	20	20	21	21	22	22	23	23
	2 901	2 923	3 107	3 397	3 621	3 748	3 857	3 980	4 124	4 218
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	963	956	1 060	1 301	1 471	1 458	1 437	1 406	1 436	1 350
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2 722	2 767	2 920	3 248	3 508	3 536	3 554	3 562	3 653	3 616
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	168	145	176	138	101	199	290	405	458	588
Other Comprehensive Income	(13)	0	0	0	-	-	-	-	-	-
Comprehensive Income	155	145	176	138	101	199	290	405	458	588
* Additional General Consumers Revenue										
Percent Increase	-0.99%	-0.99%	-0.99%	-0.99%	3.81%	3.81%	3.81%	3.81%	3.81%	2.00%
Cumulative Percent Increase	35.40%	34.06%	32.73%	31.42%	36.42%	41.62%	47.01%	52.61%	58.42%	61.59%
Financial Ratios										
Equity	20%	20%	20%	20%	20%	21%	22%	23%	25%	27%
Interest Coverage	1.13	1.10	1.12	1.09	1.07	1.13	1.19	1.27	1.31	1.42
Capital Coverage	1.81	1.69	1.63	1.73	1.72	1.97	2.04	2.15	2.79	2.50

PUB/MH II-19

Reference: First Quarter Report

The quarterly report states "the rate increases will also provide sufficient revenues for the Corporation to meet its ongoing costs of operations".

What level of annual rate increases will be required to maintain a minimum 25% equity throughout the forecast period?

ANSWER:

The following scenario provides the minimum rate changes required to maintain a 25% equity throughout the forecast period.

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
MAINTAIN 75:25 DEBT TO EQUITY RATIO
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
General Consumers											
at approved rates	1,186	1,290	1,294	1,306	1,313	1,330	1,350	1,361	1,382	1,403	1,422
additional*	0	45	939	471	438	420	585	517	568	734	580
Extraprovincial	363	341	363	394	469	502	531	554	611	821	913
Other	7	16	16	16	17	17	17	18	18	18	19
	1,556	1,693	2,612	2,188	2,237	2,269	2,483	2,450	2,578	2,976	2,933
EXPENSES											
Operating and Administrative	398	447	532	542	548	554	571	580	595	611	622
Finance Expense	385	440	438	451	461	474	523	623	644	966	907
Depreciation and Amortization	353	401	354	358	375	387	422	468	483	550	576
Water Rentals and Assessments	119	106	112	113	113	113	113	113	114	123	128
Fuel and Power Purchased	146	182	158	187	193	204	220	236	249	256	257
Capital and Other Taxes	82	87	92	99	107	116	126	132	139	128	134
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8
	1,492	1,672	1,695	1,757	1,805	1,856	1,983	2,160	2,234	2,642	2,631
Non-controlling Interest	-	(1)	(1)	(1)	(2)	(2)	(2)	(3)	(3)	(3)	(10)
Net Income	64	20	916	430	430	411	498	288	341	331	292
* Additional General Consumers Revenue											
Percent Increase	0.00%	3.57%	65.18%	-21.17%	-1.99%	-1.32%	8.94%	-3.74%	2.23%	8.00%	-7.60%
Cumulative Percent Increase	0.00%	4.50%	72.62%	36.07%	33.36%	31.59%	43.36%	37.99%	41.07%	52.35%	40.77%
Financial Ratios											
Equity	26%	24%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Interest Coverage	1.12	1.03	2.49	1.64	1.58	1.49	1.54	1.29	1.31	1.26	1.24
Capital Coverage	1.04	1.07	3.26	2.09	2.26	2.21	2.46	1.99	2.15	2.49	2.32

ELECTRIC OPERATIONS (MH11-2)
PROJECTED OPERATING STATEMENT
MAINTAIN 75:25 DEBT TO EQUITY RATIO
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
General Consumers										
at approved rates	1,441	1,460	1,479	1,498	1,521	1,541	1,562	1,582	1,602	1,622
additional*	494	459	447	284	360	379	435	421	461	417
Extraprovincial	931	946	1,124	1,408	1,526	1,544	1,539	1,544	1,565	1,574
Other	19	20	20	20	21	21	22	22	23	23
	2,885	2,885	3,069	3,211	3,427	3,486	3,558	3,569	3,650	3,636
EXPENSES										
Operating and Administrative	634	646	669	676	688	700	713	727	741	755
Finance Expense	879	870	970	1,211	1,387	1,384	1,378	1,366	1,421	1,369
Depreciation and Amortization	579	583	615	682	733	741	753	761	793	814
Water Rentals and Assessments	129	128	135	148	153	153	153	154	155	155
Fuel and Power Purchased	269	301	282	279	301	320	332	347	359	372
Capital and Other Taxes	140	145	151	153	154	156	158	160	161	162
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	2,639	2,681	2,830	3,158	3,424	3,463	3,496	3,522	3,637	3,635
Non-controlling Interest	(10)	(11)	(11)	(11)	(12)	(12)	(13)	(13)	(14)	(14)
Net Income	235	192	228	42	(9)	11	49	34	(1)	(13)
* Additional General Consumers Revenue										
Percent Increase	-4.60%	-2.12%	-0.94%	-8.63%	3.96%	0.76%	2.61%	-0.98%	1.70%	-2.39%
Cumulative Percent Increase	34.30%	31.45%	30.21%	18.97%	23.68%	24.62%	27.87%	26.62%	28.78%	25.70%
Financial Ratios										
Equity	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Interest Coverage	1.19	1.15	1.17	1.03	0.99	1.01	1.03	1.02	1.00	0.99
Capital Coverage	1.97	1.79	1.71	1.54	1.50	1.60	1.60	1.50	1.83	1.48

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ANSWER:

Progression of Project Costs in $ M									
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF-10	CEF-11
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275	1,275	1,375
Wuskwatim Transmission		199	200	257	320	316	316	291	298
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591	1,566	1,673
Herblet Lake Transmission	57	55	54	54	95	93	93	75	75
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248	3,280	3,280
Riel C.S.	96	101	103	103	105	268	268	268	268
Kelsey G.S.	121	121	166	166	184	190	190	302	302
Kettle G.S.		61	61	61	61	76	76	166	166
Pointe du Bois Improvements and Upgrades	421	288	692	834	818	818			
Pointe du Bois Spillway							318	398	398
Pointe du Bois Trans.					83	86	86	86	86
Pointe du Bois Rebuild								1,538	1,538
Slave Falls G.S.				179	192	198	198	223	230
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325	7,771	7,771
Keeyask G.S.						3,700	4,592	5,637	5,637
500 KV Dorsey U.S. Border						205	205	205	205

2,043 6,109 8,607 9,606 10,359 14,451 16,190 21,515 21,629

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CAPITAL E NDITURE FORECAST (CEF11-2)

(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
ELECTRIC													
Major New Generation & Transmission													
Wuskwatim - Generation	1,374.6	181.1	65.3	5.9	-	-	-	-	-	-	-	-	252.3
Wuskwatim - Transmission	297.4	31.6	-	-	-	-	-	-	-	-	-	-	31.6
Herblet Lake – The Pas 230 kV Transmission	74.9	6.4	0.7	-	-	-	-	-	-	-	-	-	7.2
Keeyask - Generation	5,636.9	115.6	163.4	198.2	401.1	662.9	895.6	1,041.0	786.3	716.4	189.2	45.4	5,215.1
Conawapa - Generation	7,770.8	104.4	105.2	66.1	67.2	188.1	235.4	296.8	322.6	764.7	1,229.5	1,222.9	4,603.0
Kelsey Improvements & Upgrades	301.7	34.4	24.8	20.2	0.4	-	-	-	-	-	-	-	79.7
Kettle Improvements & Upgrades	165.7	13.7	22.9	20.4	20.7	7.3	7.4	7.6	7.7	7.9	8.0	8.2	131.9
Pointe du Bois Spillway Replacement	398.2	41.1	113.6	100.4	77.1	13.0	-	-	-	-	-	-	345.2
Pointe du Bois - Transmission	85.9	14.5	11.1	18.2	16.4	-	-	-	-	-	-	-	60.2
Pointe du Bois Powerhouse Rebuild	1,538.3	-	-	-	-	-	-	-	-	-	-	0.5	0.5
Bipole III - Transmission Line	1,259.9	31.0	52.8	135.4	330.9	353.9	239.0	73.4	-	-	-	-	1,216.3
Bipole III - Converter Stations	1,828.5	50.7	141.6	315.4	330.6	353.5	356.3	163.2	58.8	-	-	-	1,770.0
Bipole III - Collector Lines	191.4	9.9	57.8	46.9	22.6	25.2	18.5	10.1	-	-	-	-	191.1
Riel 230/ 500 kV Station	267.6	74.8	67.7	47.5	-	-	-	-	-	-	-	-	190.0
Firm Import Upgrades	19.9	0.2	19.7	-	-	-	-	-	-	-	-	-	19.9
Dorsey - US Border New 500kV Transmission Line	204.8	0.1	0.8	0.4	2.0	3.6	34.0	84.0	79.0	-	-	-	203.9
St. Joseph Wind Transmission	11.2	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Demand Side Management	NA	31.8	33.6	-	-	-	-	-	-	-	-	-	65.4
Generating Station Improvements & Upgrades	649.0	-	-	-	-	-	-	-	-	-	45.0	32.2	77.3
Single Cycle Gas Turbines	65.6	-	-	-	-	-	-	-	-	-	-	-	-
Additional North South Trasmission	318.2	-	-	-	-	-	-	-	-	-	-	-	-
Target Adjustment	NA	(87.8)	(118.3)	85.0	(45.4)	(40.7)	(175.7)	277.0	(77.3)	(77.0)	(26.0)	(3.2)	(289.4)
		656.1	762.6	1,060.0	1,223.4	1,566.9	1,610.5	1,953.0	1,177.1	1,412.0	1,445.8	1,306.0	14,173.5

CAPITAL E... NDITURE FORECAST (CEF11-2)

(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Power Supply													
HVDC Auxiliary Power Supply Upgrades	5.3	0.5	0.4	-	-	-	-	-	-	-	-	-	0.9
Dorsey Synchronous Condenser Refurbishment	78.3	4.6	5.3	5.1	7.7	11.7	11.4	8.3	-	-	-	-	54.2
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	0.5	0.3	0.3	0.1	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	171.7	4.6	17.6	15.5	17.2	14.0	9.7	-	-	-	-	-	78.5
HVDC Transformer Replacement Program Extended	449.7	-	-	-	-	-	-	-	-	-	0.5	4.6	5.2
Dorsey 230 kV Relay Building Upgrade	82.2	1.6	2.2	17.7	35.1	12.5	3.1	-	-	-	-	-	72.2
HVDC Stations Ground Grid Refurbishment	4.3	0.4	0.4	0.4	0.3	0.5	-	-	-	-	-	-	2.1
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	15.9	2.1	1.1	1.0	0.2	0.5	0.1	0.1	0.0	-	-	-	5.2
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	1.1	2.2	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.4	2.3	11.1	6.0	-	-	-	-	-	-	-	19.8
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	0.2	2.7	2.4	5.6	-	-	-	-	-	-	11.0
HVDC Smoothing Reactor Replacements	39.3	20.6	1.8	0.7	-	-	-	-	-	-	-	-	23.1
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separation	3.2	0.4	1.2	1.5	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.2	1.3	1.1	3.0	3.8	2.4	-	-	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	0.6	1.0	1.7	5.3	0.0	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	0.1	-	3.3	4.8	4.0	4.2	2.3	-	-	-	-	18.7
HVDC Bipole 2 Upgrades & Replacements	444.2	-	-	-	-	-	-	-	-	-	12.3	52.7	65.0
HVDC Bipole 1 CQ Disconnect Replacement	5.2	0.3	0.9	1.5	1.0	1.1	0.3	-	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	1.2	-	-	-	-	-	-	-	-	-	-	1.2
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	0.4	2.7	1.2	1.2	-	-	-	-	-	-	-	5.5
HVDC Gapped Arrestor Replacement	16.3	0.2	1.0	3.9	3.4	7.0	0.1	-	-	-	-	-	15.7
Converter Transformer Bushing Replacement	5.9	0.4	1.0	0.5	-	-	-	-	-	-	-	-	1.9
Winnipeg River Riverbank Protection Program	19.7	1.5	1.4	1.3	1.3	1.3	0.8	-	-	-	-	-	7.5
Power Supply Hydraulic Controls	20.5	1.0	0.7	1.3	-	-	-	2.1	2.6	0.9	-	-	8.6
Slave Falls GS Creek Spillway Rehab	11.1	0.0	1.0	1.9	8.1	-	-	-	-	-	-	-	11.1
Slave Falls Rehabilitation	230.2	9.0	2.6	4.3	31.7	40.6	45.8	42.0	11.3	-	-	-	187.3
Great Falls Unit 4 Major Overhaul	43.5	11.4	21.6	0.8	-	-	-	-	-	-	-	-	33.8
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	2.2	17.1	5.4	-	-	-	-	-	24.8
Generation South Overhauls & Improvements	384.8	-	-	-	-	-	-	-	-	-	4.7	10.2	14.8
Pine Falls Rehabilitation	166.7	4.0	21.0	26.9	40.3	46.8	14.0	0.1	-	-	-	-	153.0
Generation South Transformer Refurbish & Spares	27.6	0.6	7.0	13.8	4.3	0.5	0.5	-	-	-	-	-	26.6
Water Licenses & Renewals	54.6	5.2	5.6	6.2	6.3	6.5	6.5	3.9	-	-	-	-	40.2
Generation South PCB Regulation Compliance	4.7	0.5	0.4	0.4	0.2	2.7	-	-	-	-	-	-	4.1
Kettle Transformer Overhaul Program	35.6	9.1	7.1	7.9	0.7	-	-	-	-	-	-	-	24.8
Generation South Breaker Replacements	11.1	1.7	3.8	0.5	1.0	0.4	1.2	-	-	-	-	-	8.5
Seven Sisters Upgrades	14.4	4.4	1.6	0.6	-	-	-	-	-	-	-	-	6.6
Generation South Excitation Upgrades	18.3	1.3	1.5	2.3	1.9	2.5	1.0	0.7	6.9	0.2	-	-	18.3
Generation South Excitation Program Extended	14.0	-	-	-	-	-	-	-	-	-	4.4	5.0	9.4
Laurie River/Churchill River Diversion (CRD) Comm and Annunciation Upgrade	4.8	2.1	1.9	-	-	-	-	-	-	-	-	-	4.0
Notigi Marine Vessel Replacement and Infrastructure Improvements	4.6	0.3	4.1	-	-	-	-	-	-	-	-	-	4.4
Limestone Stilling Basin Rehabilitation	2.0	0.0	0.4	1.6	-	-	-	-	-	-	-	-	2.0
Pointe Du Bois GS Rehabilitation	50.0	6.3	19.8	19.5	4.4	-	-	-	-	-	-	-	49.9
Kettle Wicket Gates Lever Refurbishments	2.3	-	1.1	1.2	-	-	-	-	-	-	-	-	2.3
Limestone Governor Control Repl	2.5	-	0.3	1.3	0.9	-	-	-	-	-	-	-	2.5
Limestone GSCADA Replacement	5.3	-	0.4	1.3	0.8	0.9	0.4	1.5	-	-	-	-	5.3
Jenpeg Unit Overhauls	128.1	-	-	-	-	2.2	2.5	18.0	23.7	24.2	24.6	20.8	115.9
Power Supply Dam Safety Upgrades	64.5	7.4	10.6	5.0	-	-	-	-	-	-	-	-	23.1
Brandon Unit 5 License Review	18.7	0.2	0.2	2.6	10.4	0.0	-	-	-	-	-	-	13.4
Selkirk Enhancements	14.2	0.4	0.9	-	-	-	-	-	-	-	-	-	1.3
Fire Protection Projects - HVDC	7.2	0.4	0.2	1.2	2.9	-	-	-	-	-	-	-	4.7
Halon Replacement Project	36.4	1.6	5.2	2.6	3.5	2.2	0.9	-	-	-	-	-	16.0
Oil Containment – Power Supply	19.1	0.7	0.5	0.7	0.4	0.6	0.3	-	-	-	-	-	3.1
Grand Rapids Townsite House Renovations	5.2	1.1	0.9	0.9	0.9	0.0	-	-	-	-	-	-	3.9
Grand Rapids Fish Hatchery	2.2	1.2	0.8	-	-	-	-	-	-	-	-	-	2.0
Generation Townsite Infrastructure	52.1	9.0	1.9	-	-	-	-	-	-	-	-	-	10.9
Site Remediation of Contaminated Corporate Facilities	32.8	1.6	1.1	-	-	-	-	-	-	-	-	-	2.7
High Voltage Test Facility	40.6	13.7	0.4	-	-	-	-	-	-	-	-	-	14.1
Power Supply Security Installations / Upgrades	43.2	5.6	7.9	9.7	4.7	-	-	-	-	-	-	-	27.8
Power Supply Sewer & Domestic Water System Install and Upgrade	37.9	6.4	2.9	1.0	2.4	1.6	2.4	3.1	0.1	-	-	-	19.9
Power Supply Domestic	NA	19.7	20.1	20.5	21.0	21.4	21.8	22.2	22.7	23.1	23.6	24.1	240.3
Target Adjustment	NA	(10.7)	(60.3)	(57.3)	(76.4)	(77.5)	(30.6)	(19.6)	(1.6)	0.5	0.8	(2.8)	(335.5)
		155.6	137.6	150.4	163.9	130.5	104.1	84.8	65.6	48.9	70.8	114.6	1,226.7

CAPITAL E[illegible]NDITURE FORECAST (CEF11-2)

(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Transmission													
Winnipeg - Brandon Transmission System Improvements	44.8	3.0	0.8	4.1	28.7	3.7	-	-	-	-	-	-	40.3
Transcona East 230 - 66 kV Station	33.1	24.1	-	-	-	-	-	-	-	-	-	-	24.1
Brandon Area Transmission Improvements	11.8	4.4	6.3	1.0	-	-	-	-	-	-	-	-	11.6
Neepawa 230 - 66 kV Station	30.0	14.1	8.0	4.5	-	-	-	-	-	-	-	-	26.6
Transmission Line Re-Rating	31.8	2.9	6.4	-	-	-	-	-	-	-	-	-	9.3
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	0.8	0.9	2.6	6.1	9.7	12.1	-	32.2
Transcona Station 66 kV Breaker Replacement	6.0	0.4	2.9	1.5	1.1	0.0	-	-	-	-	-	-	6.0
13.2kV Shunt Reactor Replacements	33.0	2.2	4.9	0.9	0.8	2.2	2.3	2.3	17.5	-	-	-	33.0
Lake Winnipeg East System Improvements	66.9	2.3	5.7	15.4	29.2	14.2	0.1	-	-	-	-	-	66.8
Canexus Load Addition	(0.2)	0.9	0.1	-	-	-	-	-	-	-	-	-	1.0
D602F 500kV T/L Footing Replacements	4.4	4.4	-	-	-	-	-	-	-	-	-	-	4.4
Stanley Station 230-66 kV Transformer Addition	21.1	0.0	1.8	7.3	7.9	4.0	-	-	-	-	-	-	21.1
Enbridge Pipelines: Clipper Project Load Addition Phase 2	7.5	1.8	1.9	0.0	-	-	-	-	-	-	-	-	3.7
Ashern Station Bank Addition	10.6	0.2	1.6	1.5	7.0	0.2	-	-	-	-	-	-	10.6
Ashern Station 230 kV Shunt Reactor Replacement	2.7	0.9	1.8	-	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Diesel Tank Farm Upgrade	1.1	(1.0)	0.7	-	-	-	-	-	-	-	-	-	(0.4)
Energy Management System (EMS) Upgrade	6.6	2.8	2.0	-	-	-	-	-	-	-	-	-	4.8
Transmission Line Protection & Teleprotection Replacement	21.1	3.1	3.4	2.8	2.8	2.9	2.4	-	-	-	-	-	17.5
Winnipeg Central Protection Wireline Replacement	10.5	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Mobile Radio System Modernization	30.7	1.9	6.4	2.8	11.6	7.9	-	-	-	-	-	-	30.5
Site Remediation of Diesel Generating Stations	13.3	2.3	0.7	-	-	-	-	-	-	-	-	-	3.0
Oil Containment - Transmission	7.4	0.4	0.0	-	-	-	-	-	-	-	-	-	0.4
Station Battery Bank Capacity & System Reliability Increase	46.5	4.8	5.1	4.9	5.0	5.2	-	-	-	-	-	-	25.0
Waverley Service Centre Oil Tank Farm Replacement	3.0	0.5	0.4	0.7	-	-	-	-	-	-	-	-	1.6
115 kV Transmission Lines	298.9	-	-	-	-	-	-	-	-	-	10.3	16.1	26.4
230 kV Transmission Lines	171.1	-	-	-	-	-	-	-	-	-	5.9	9.2	15.1
Sub-Transmission	124.8	-	-	-	-	-	-	-	-	-	4.3	6.7	11.0
Communications	425.8	-	-	-	-	-	-	-	-	-	14.7	23.0	37.6
Site Remediation	NA	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Domestic	NA	30.6	31.2	31.8	32.5	33.1	33.8	34.5	35.1	35.9	36.6	37.3	372.3
Target Adjustment	NA	(24.3)	(13.4)	27.3	(38.2)	(13.6)	(0.1)	2.2	(14.5)	0.0	1.0	1.8	(71.9)
		83.1	78.7	106.5	88.6	60.7	39.3	41.6	44.1	45.6	84.8	94.1	767.0
Customer Service & Distribution													
Winnipeg Distribution Infrastructure Requirements	24.5	2.3	2.3	2.9	-	-	-	-	-	-	-	-	7.5
Rover Substation Replace 4 kV Switchgear	12.7	0.0	0.1	1.7	2.5	2.8	0.5	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	1.2	11.9	8.1	2.2	-	-	-	-	-	-	-	23.3
Frobisher Station Upgrade	14.4	0.5	1.0	-	-	-	-	-	-	-	-	-	1.5
Burrows New 66 kV/ 12 kV Station	28.6	12.1	6.7	-	-	-	-	-	-	-	-	-	18.9
Winnipeg Central 12&4kV Manhole Oil Switches	9.8	1.4	-	-	-	-	-	-	-	-	-	-	1.4
William New 66 kV/ 12 kV Station	10.3	0.5	2.2	2.9	3.2	1.1	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	0.7	-	-	-	-	-	-	-	-	-	-	0.7
St. James New Station & 24 kV Conversion	65.9	0.6	6.3	3.9	9.5	21.8	23.6	-	-	-	-	-	65.7
Distribution	887.5	-	-	-	-	-	-	-	-	-	30.5	47.9	78.4
York Station Bank & Switchgear Addition	6.0	1.4	-	-	-	-	-	-	-	-	-	-	1.4
Defective RINJ Cable Replacement	8.7	1.3	1.3	-	-	-	-	-	-	-	-	-	2.7
Health Sciences Centre Service Consolidation & Distribution Upgrade	15.8	2.0	5.0	3.6	4.0	0.6	-	-	-	-	-	-	15.2
Waverley South DSC Installation	3.9	2.7	-	-	-	-	-	-	-	-	-	-	2.7
Southdale DK732 Cable Replacement	2.6	0.9	1.2	-	-	-	-	-	-	-	-	-	2.1
Steinbach Area 66kV Capacity Upgrade	6.3	5.9	0.3	-	-	-	-	-	-	-	-	-	6.2
Line 27 66 kV Extension and Arborg North Distribution Supply Centre	6.0	4.3	1.2	-	-	-	-	-	-	-	-	-	5.4
AECL Station Switchgear Replacement	2.4	0.8	-	-	-	-	-	-	-	-	-	-	0.8
Melrose DSC	3.5	3.5	-	-	-	-	-	-	-	-	-	-	3.5
Starbuck DSC	3.0	3.0	-	-	-	-	-	-	-	-	-	-	3.0
Enbridge Pipelines Clipper-66kV Supply I	0.9	2.1	-	-	-	-	-	-	-	-	-	-	2.1
Teulon East 66-12 kV Station	4.6	4.2	-	-	-	-	-	-	-	-	-	-	4.2
Waskada New 66-25kV Distrib'n Supply Ctr	3.9	3.9	-	-	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25kV Conversion	4.3	0.2	1.2	-	-	-	-	-	-	-	-	-	1.3
Brandon Crocus Plains 115-25 kV Bank Addition	6.3	0.0	0.0	0.0	6.2	-	-	-	-	-	-	-	6.2
Birtle South - Rossburn 66kV Line	4.9	-	-	0.1	0.3	4.5	-	-	-	-	-	-	4.9
TCPL Keystone Project	8.0	2.1	2.4	-	-	-	-	-	-	-	-	-	4.5
Line 98 Rebuild Melita to Waskada	3.8	3.8	-	-	-	-	-	-	-	-	-	-	3.8
Customer Service & Distribution Domestic	NA	127.9	130.5	133.2	136.3	139.0	141.8	144.7	147.5	150.5	153.5	156.6	1,561.5
Target Adjustment	NA	(30.3)	(6.8)	(11.2)	(21.6)	(18.7)	(14.8)	(9.6)	(9.8)	(10.0)	(10.2)	(10.4)	(153.6)
		159.0	166.8	145.1	142.5	151.1	151.2	135.0	137.7	140.5	173.8	194.0	1,696.6

CAPITAL E[illegible]NDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	11 Year Total
Customer Care & Marketing													
Advanced Metering Infrastructure	30.9	-	4.0	5.3	5.4	5.6	4.3	4.2	-	-	-	-	28.8
Customer Care & Marketing Domestic	NA	3.0	3.0	3.1	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	42.0
Target Adjustment	NA	3.6	1.0	(0.3)	(0.9)	(2.3)	(1.2)	(5.4)	(1.1)	(1.2)	(1.2)	(1.2)	(10.2)
		6.6	8.0	8.1	8.4	7.2	7.1	2.9	3.0	3.1	3.1	3.2	60.7
Finance & Administration													
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
EAM Phase 2	19.3	6.1	8.9	2.3	-	-	-	-	-	-	-	-	17.3
Workforce Management (Phase 1 to 4)	15.7	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Fleet	NA	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	16.2	16.5	16.8	167.7
Finance & Administration Domestic	NA	24.9	25.4	25.9	26.5	27.0	27.5	28.1	28.7	29.2	29.8	30.4	303.5
Target Adjustment	NA	(8.4)	(8.9)	(2.3)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(19.8)
		46.7	47.5	48.3	49.1	49.9	50.7	51.6	52.5	53.3	54.3	55.2	559.0
ELECTRIC CAPITAL SUBTOTAL		1,107.1	1,201.1	1,518.2	1,675.9	1,966.2	1,962.9	2,268.9	1,480.0	1,703.3	1,832.6	1,767.1	18,483.4
GAS													
Customer Service & Distribution													
Ile Des Chenes NG Transmission Network Upgrade	1.2	0.3	0.9	-	-	-	-	-	-	-	-	-	1.2
Gas SCADA Replacement	4.6	3.6	-	-	-	-	-	-	-	-	-	-	3.6
Buncloudy Natural Gas Crossing at Souris River	1.6	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Customer Service & Distribution Domestic	NA	25.2	25.7	26.2	26.7	27.3	27.8	28.4	28.9	29.5	30.1	30.7	306.5
Target Adjustment	NA	(6.2)	(4.5)	(3.7)	(3.7)	(3.8)	(3.9)	(4.0)	(4.0)	(4.1)	(4.2)	(4.3)	(46.4)
		24.6	22.1	22.5	23.0	23.4	23.9	24.4	24.9	25.4	25.9	26.4	266.5
Customer Care & Marketing													
Advanced Metering Infrastructure	15.0	-	1.0	5.4	8.4	-	-	-	-	-	-	-	14.7
Demand Side Management	NA	12.6	13.4	-	-	-	-	-	-	-	-	-	26.1
Customer Care & Marketing Domestic	NA	4.8	4.8	4.9	5.0	5.1	5.2	5.3	5.4	5.5	5.7	5.8	57.7
Target Adjustment	NA	(1.5)	1.4	(1.2)	(11.9)	(2.9)	(2.9)	(2.1)	(2.7)	(2.8)	(2.3)	(2.3)	(31.1)
		15.9	20.7	9.1	1.5	2.3	2.4	3.3	2.7	2.7	3.4	3.5	67.3
GAS CAPITAL SUBTOTAL		40.5	42.8	31.6	24.5	25.7	26.3	27.7	27.6	28.1	29.3	29.9	333.9
CONSOLIDATED CAPITAL		1,147.6	1,243.9	1,549.8	1,700.4	1,991.9	1,989.1	2,296.6	1,507.6	1,731.5	1,861.9	1,797.0	18,817.3
Target Adjustment	NA	(33.6)	(0.0)	0.0	0.0	31.1	87.9	135.9	160.3	182.2	51.8	5.2	620.8
CEF11-2 TOTAL		1,114.1	1,243.9	1,549.8	1,700.4	2,022.9	2,077.0	2,432.5	1,667.9	1,913.6	1,913.7	1,802.1	19,438.1

CAPITAL E. :NDITURE FORECAST (CEF11-2)

(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	21 Year Total
ELECTRIC												
Major New Generation & Transmission												
Wuskwatim - Generation	1,374.6	-	-	-	-	-	-	-	-	-	-	252.3
Wuskwatim - Transmission	297.4	-	-	-	-	-	-	-	-	-	-	31.6
Herblet Lake -- The Pas 230 kV Transmission	74.9	-	-	-	-	-	-	-	-	-	-	7.2
Keeyask - Generation	5,636.9	-	-	-	-	-	-	-	-	-	-	5,215.1
Conawapa - Generation	7,770.8	1,042.6	909.5	691.8	281.3	41.0	-	-	-	-	-	7,569.1
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	79.7
Kettle Improvements & Upgrades	165.7	7.7	-	-	-	-	-	-	-	-	-	139.6
Pointe du Bois Spillway Replacement	398.2	-	-	-	-	-	-	-	-	-	-	345.2
Pointe du Bois - Transmission	85.9	-	-	-	-	-	-	-	-	-	-	60.2
Pointe du Bois Powerhouse Rebuild	1,538.3	2.2	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	55.6	1,538.3
Bipole III - Transmission Line	1,259.9	-	-	-	-	-	-	-	-	-	-	1,216.3
Bipole III - Converter Stations	1,828.5	-	-	-	-	-	-	-	-	-	-	1,770.0
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	191.1
Riel 230/ 500 kV Station	267.6	-	-	-	-	-	-	-	-	-	-	190.0
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.9
Dorsey - US Border New 500kV Transmission Line	204.8	-	-	-	-	-	-	-	-	-	-	203.9
St. Joseph Wind Transmission	11.2	-	-	-	-	-	-	-	-	-	-	2.3
Demand Side Management	NA	-	-	-	-	-	-	-	-	-	-	65.4
Generating Station Improvements & Upgrades	649.0	21.1	9.4	14.4	15.2	25.8	79.3	56.6	62.7	174.5	112.6	649.0
Single Cycle Gas Turbines	65.6	-	-	-	-	-	-	-	-	8.4	57.2	65.6
Additional North South Trasmission	318.2	-	-	-	318.2	-	-	-	-	-	-	318.2
Target Adjustment	NA	(1.8)	(1.7)	306.3	(319.8)	(0.5)	(0.5)	(0.5)	(0.5)	(8.9)	-	(317.2)
		1,071.8	933.3	1,050.2	385.6	224.1	323.8	460.0	374.9	390.2	225.5	19,612.8

CAPITAL E NDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	21 Year Total
Power Supply												
HVDC Auxiliary Power Supply Upgrades	5.3	-	-	-	-	-	-	-	-	-	-	0.9
Dorsey Synchronous Condenser Refurbishment	78.3	-	-	-	-	-	-	-	-	-	-	54.2
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	-	-	-	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	171.7	-	-	-	-	-	-	-	-	-	-	78.5
HVDC Transformer Replacement Program Extended	449.7	6.4	32.9	6.7	7.0	50.3	22.5	77.8	88.1	39.3	113.5	449.7
Dorsey 230 kV Relay Building Upgrade	82.2	-	-	-	-	-	-	-	-	-	-	72.2
HVDC Stations Ground Grid Refurbishment	4.3	-	-	-	-	-	-	-	-	-	-	2.1
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	15.9	-	-	-	-	-	-	-	-	-	-	5.2
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	-	-	-	-	-	-	-	-	-	-	19.8
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	-	-	-	-	-	-	-	-	11.0
HVDC Smoothing Reactor Replacements	39.3	-	-	-	-	-	-	-	-	-	-	23.1
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separation	3.2	-	-	-	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	-	-	-	-	-	-	-	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	-	-	-	-	-	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	-	-	-	-	-	-	-	-	-	-	18.7
HVDC Bipole 2 Upgrades & Replacements	444.2	57.4	64.1	98.1	103.5	56.2	-	-	-	-	-	444.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	-	-	-	-	-	-	-	-	-	5.2
HVDC Bipole 2 Thyristor Module Cooling Refurbishment	4.7	-	-	-	-	-	-	-	-	-	-	1.2
HVDC Bipole 1 Transformer Marshalling Kiosk Replacement	6.8	-	-	-	-	-	-	-	-	-	-	5.5
HVDC Gapped Arrestor Replacement	16.3	-	-	-	-	-	-	-	-	-	-	15.7
Converter Transformer Bushing Replacement	5.9	-	-	-	-	-	-	-	-	-	-	1.9
Winnipeg River Riverbank Protection Program	19.7	-	-	-	-	-	-	-	-	-	-	7.5
Power Supply Hydraulic Controls	20.5	-	-	-	-	-	-	-	-	-	-	8.6
Slave Falls GS Creek Spillway Rehab	11.1	-	-	-	-	-	-	-	-	-	-	11.1
Slave Falls Rehabilitation	230.2	-	-	-	-	-	-	-	-	-	-	187.3
Great Falls Unit 4 Major Overhaul	43.5	-	-	-	-	-	-	-	-	-	-	33.8
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	-	-	-	-	-	-	-	24.8
Generation South Overhauls & Improvements	384.8	40.3	29.4	48.6	28.5	33.3	82.8	53.3	53.7	-	-	384.8
Pine Falls Rehabilitation	166.7	-	-	-	-	-	-	-	-	-	-	153.0
Generation South Transformer Refurbish & Spares	27.6	-	-	-	-	-	-	-	-	-	-	26.6
Water Licenses & Renewals	54.6	-	-	-	-	-	-	-	-	-	-	40.2
Generation South PCB Regulation Compliance	4.7	-	-	-	-	-	-	-	-	-	-	4.1
Kettle Transformer Overhaul Program	35.6	-	-	-	-	-	-	-	-	-	-	24.8
Generation South Breaker Replacements	11.1	-	-	-	-	-	-	-	-	-	-	8.5
Seven Sisters Upgrades	14.4	-	-	-	-	-	-	-	-	-	-	6.6
Generation South Excitation Upgrades	18.3	-	-	-	-	-	-	-	-	-	-	18.3
Generation South Excitation Program Extended	14.0	3.4	1.2	-	-	-	-	-	-	-	-	14.0
Laurie River/Churchill River Diversion (CRD) Comm and Annunciation Upgrade	4.8	-	-	-	-	-	-	-	-	-	-	4.0
Notigi Marine Vessel Replacement and Infrastructure Improvements	4.6	-	-	-	-	-	-	-	-	-	-	4.4
Limestone Stilling Basin Rehabilitation	2.0	-	-	-	-	-	-	-	-	-	-	2.0
Pointe Du Bois GS Rehabilitation	50.0	-	-	-	-	-	-	-	-	-	-	49.9
Kettle Wicket Gates Lever Refurbishments	2.3	-	-	-	-	-	-	-	-	-	-	2.3
Limestone Governor Control Repl	2.5	-	-	-	-	-	-	-	-	-	-	2.5
Limestone GSCADA Replacement	5.3	-	-	-	-	-	-	-	-	-	-	5.3
Jenpeg Unit Overhauls	128.1	-	-	-	-	-	-	-	-	-	-	115.9
Power Supply Dam Safety Upgrades	64.5	-	-	-	-	-	-	-	-	-	-	23.1
Brandon Unit 5 License Review	18.7	-	-	-	-	-	-	-	-	-	-	13.4
Selkirk Enhancements	14.2	-	-	-	-	-	-	-	-	-	-	1.3
Fire Protection Projects - HVDC	7.2	-	-	-	-	-	-	-	-	-	-	4.7
Halon Replacement Project	36.4	-	-	-	-	-	-	-	-	-	-	16.0
Oil Containment – Power Supply	19.1	-	-	-	-	-	-	-	-	-	-	3.1
Grand Rapids Townsite House Renovations	5.2	-	-	-	-	-	-	-	-	-	-	3.9
Grand Rapids Fish Hatchery	2.2	-	-	-	-	-	-	-	-	-	-	2.0
Generation Townsite Infrastructure	52.1	-	-	-	-	-	-	-	-	-	-	10.9
Site Remediation of Contaminated Corporate Facilities	32.8	-	-	-	-	-	-	-	-	-	-	2.7
High Voltage Test Facility	40.6	-	-	-	-	-	-	-	-	-	-	14.1
Power Supply Security Installations / Upgrades	43.2	-	-	-	-	-	-	-	-	-	-	27.8
Power Supply Sewer & Domestic Water System Install and Upgrade	37.9	-	-	-	-	-	-	-	-	-	-	19.9
Power Supply Domestic	NA	24.6	25.0	25.5	26.1	26.6	27.1	27.7	28.2	28.8	29.3	509.2
Target Adjustment	NA	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	(335.8)
		132.0	152.6	178.9	165.0	166.4	132.4	158.7	170.0	68.1	142.9	2,693.7

CAPITAL E. .NDITURE FORECAST (CEF11-2)

(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	21 Year Total
Transmission												
Winnipeg - Brandon Transmission System Improvements	44.8	-	-	-	-	-	-	-	-	-	-	40.3
Transcona East 230 - 66 kV Station	33.1	-	-	-	-	-	-	-	-	-	-	24.1
Brandon Area Transmission Improvements	11.8	-	-	-	-	-	-	-	-	-	-	11.6
Neepawa 230 - 66 kV Station	30.0	-	-	-	-	-	-	-	-	-	-	26.6
Transmission Line Re-Rating	31.8	-	-	-	-	-	-	-	-	-	-	9.3
St Vital-Steinbach 230 kV Transmission	32.2	-	-	-	-	-	-	-	-	-	-	32.2
Transcona Station 66 kV Breaker Replacement	6.0	-	-	-	-	-	-	-	-	-	-	6.0
13.2kV Shunt Reactor Replacements	33.0	-	-	-	-	-	-	-	-	-	-	33.0
Lake Winnipeg East System Improvements	66.9	-	-	-	-	-	-	-	-	-	-	66.8
Canexus Load Addition	(0.2)	-	-	-	-	-	-	-	-	-	-	1.0
D602F 500kV T/L Footing Replacements	4.4	-	-	-	-	-	-	-	-	-	-	4.4
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	-	-	-	-	-	-	-	-	21.1
Enbridge Pipelines: Clipper Project Load Addition Phase 2	7.5	-	-	-	-	-	-	-	-	-	-	3.7
Ashern Station Bank Addition	10.6	-	-	-	-	-	-	-	-	-	-	10.6
Ashern Station 230 kV Shunt Reactor Replacement	2.7	-	-	-	-	-	-	-	-	-	-	2.7
Tadoule Lake DGS Diesel Tank Farm Upgrade	1.1	-	-	-	-	-	-	-	-	-	-	(0.4)
Energy Management System (EMS) Upgrade	6.6	-	-	-	-	-	-	-	-	-	-	4.8
Transmission Line Protection & Teleprotection Replacement	21.1	-	-	-	-	-	-	-	-	-	-	17.5
Winnipeg Central Protection Wireline Replacement	10.5	-	-	-	-	-	-	-	-	-	-	0.4
Mobile Radio System Modernization	30.7	-	-	-	-	-	-	-	-	-	-	30.5
Site Remediation of Diesel Generating Stations	13.3	-	-	-	-	-	-	-	-	-	-	3.0
Oil Containment - Transmission	7.4	-	-	-	-	-	-	-	-	-	-	0.4
Station Battery Bank Capacity & System Reliability Increase	46.5	-	-	-	-	-	-	-	-	-	-	25.0
Waverley Service Centre Oil Tank Farm Replacement	3.0	-	-	-	-	-	-	-	-	-	-	1.6
115 kV Transmission Lines	298.9	19.8	21.1	25.8	23.7	25.5	28.4	28.9	31.5	32.9	34.8	298.9
230 kV Transmission Lines	171.1	11.3	12.1	14.8	13.6	14.6	16.3	16.5	18.0	18.8	19.9	171.1
Sub-Transmission	124.8	8.3	8.8	10.8	9.9	10.6	11.9	12.1	13.1	13.7	14.5	124.8
Communications	425.8	28.2	30.0	36.8	33.8	36.3	40.5	41.2	44.8	46.9	49.6	425.8
Site Remediation	NA	-	-	-	-	-	-	-	-	-	-	-
Transmission Domestic	NA	38.0	38.8	39.6	40.4	41.2	42.0	42.8	43.7	44.6	45.5	788.9
Target Adjustment	NA	2.2	2.3	2.9	2.6	2.8	3.1	3.2	3.5	3.6	3.9	(41.6)
		107.8	113.2	130.7	124.1	131.1	142.2	144.7	154.7	160.6	168.3	2,144.2
Customer Service & Distribution												
Winnipeg Distribution Infrastructure Requirements	24.5	-	-	-	-	-	-	-	-	-	-	7.5
Rover Substation Replace 4 kV Switchgear	12.7	-	-	-	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	28.2	-	-	-	-	-	-	-	-	-	-	23.3
Frobisher Station Upgrade	14.4	-	-	-	-	-	-	-	-	-	-	1.5
Burrows New 66 kV/ 12 kV Station	28.6	-	-	-	-	-	-	-	-	-	-	18.9
Winnipeg Central 12&4kV Manhole Oil Switches	9.8	-	-	-	-	-	-	-	-	-	-	1.4
William New 66 kV/ 12 kV Station	10.3	-	-	-	-	-	-	-	-	-	-	10.0
Waverley West Sub Division Supply - Stage 1	6.5	-	-	-	-	-	-	-	-	-	-	0.7
St. James New Station & 24 kV Conversion	65.9	-	-	-	-	-	-	-	-	-	-	65.7
Distribution	687.5	58.8	62.6	76.7	70.5	75.7	84.4	85.8	93.5	97.8	103.4	887.5
York Station Bank & Switchgear Addition	6.0	-	-	-	-	-	-	-	-	-	-	1.4
Defective RINJ Cable Replacement	8.7	-	-	-	-	-	-	-	-	-	-	2.7
Health Sciences Centre Service Consolidation & Distribution Upgrade	15.8	-	-	-	-	-	-	-	-	-	-	15.2
Waverley South DSC Installation	3.9	-	-	-	-	-	-	-	-	-	-	2.7
Southdale DK732 Cable Replacement	2.6	-	-	-	-	-	-	-	-	-	-	2.1
Steinbach Area 66kV Capacity Upgrade	6.3	-	-	-	-	-	-	-	-	-	-	6.2
Line 27 66 kV Extension and Arborg North Distribution Supply Centre	6.0	-	-	-	-	-	-	-	-	-	-	5.4
AECL Station Switchgear Replacement	2.4	-	-	-	-	-	-	-	-	-	-	0.8
Melrose DSC	3.5	-	-	-	-	-	-	-	-	-	-	3.5
Starbuck DSC	3.0	-	-	-	-	-	-	-	-	-	-	3.0
Enbridge Pipelines Clipper-66kV Supply I	0.9	-	-	-	-	-	-	-	-	-	-	2.1
Teulon East 66-12 kV Station	4.6	-	-	-	-	-	-	-	-	-	-	4.2
Waskada New 66-25kV Distrib'n Supply Ctr	3.9	-	-	-	-	-	-	-	-	-	-	3.9
Cromer North Station & Reston RE12-4 25kV Conversion	4.3	-	-	-	-	-	-	-	-	-	-	1.3
Brandon Crocus Plains 115-25 kV Bank Addition	6.3	-	-	-	-	-	-	-	-	-	-	6.2
Birtle South - Rossburn 66kV Line	4.9	-	-	-	-	-	-	-	-	-	-	4.9
TCPL Keystone Project	8.0	-	-	-	-	-	-	-	-	-	-	4.5
Line 98 Rebuild Melita to Waskada	3.8	-	-	-	-	-	-	-	-	-	-	3.8
Customer Service & Distribution Domestic	NA	159.7	162.9	166.2	169.5	172.9	176.3	179.9	183.5	187.1	190.9	3,310.3
Target Adjustment	NA	(10.6)	(10.9)	(11.1)	(11.3)	(11.5)	(11.8)	(12.0)	(12.2)	(12.5)	-	(257.5)
		207.8	214.7	231.8	228.7	237.0	249.0	253.6	264.7	272.4	294.2	4,150.6

CAPITAL E. _NDITURE FORECAST (CEF11-2)
(in millions of dollars)

	Total Project Cost	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	21 Year Total
Customer Care & Marketing												
Advanced Metering Infrastructure	30.9	-	-	-	-	-	-	-	-	-	-	26.8
Customer Care & Marketing Domestic	NA	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.2	5.3	5.4	91.2
Target Adjustment	NA	(1.2)	(1.3)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)	-	(22.3)
		3.3	3.3	3.4	3.5	3.5	3.6	3.7	3.7	3.8	5.4	97.8
Finance & Administration												
Corporate Buildings	NA	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	168.0
EAM Phase 2	19.3	-	-	-	-	-	-	-	-	-	-	17.3
Workforce Management (Phase 1 to 4)	15.7	-	-	-	-	-	-	-	-	-	-	2.3
Fleet	NA	17.1	17.5	17.8	18.2	18.6	18.9	19.3	19.7	20.1	20.5	355.4
Finance & Administration Domestic	NA	31.0	31.6	32.3	32.9	33.6	34.2	34.9	35.6	36.3	37.1	643.1
Target Adjustment	NA	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	-	(20.2)
		56.1	57.1	58.1	59.1	60.1	61.1	62.2	63.3	64.4	65.5	1,165.9
ELECTRIC CAPITAL SUBTOTAL		1,578.8	1,474.1	1,653.0	965.9	822.2	912.2	1,082.9	1,031.2	959.5	901.7	29,864.9
GAS												
Customer Service & Distribution												
Ile Des Chenes NG Transmission Network Upgrade	1.2	-	-	-	-	-	-	-	-	-	-	1.2
Gas SCADA Replacement	4.6	-	-	-	-	-	-	-	-	-	-	3.6
Buncloudy Natural Gas Crossing at Souris River	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Customer Service & Distribution Domestic	NA	31.3	31.9	32.6	33.2	33.9	34.6	35.3	36.0	36.7	37.4	649.4
Target Adjustment	NA	(4.4)	(4.5)	(4.6)	(4.6)	(4.7)	(4.8)	(4.9)	(5.0)	(5.1)	(5.2)	(94.4)
		26.9	27.5	28.0	28.6	29.2	29.7	30.3	30.9	31.6	32.2	561.5
Customer Care & Marketing												
Advanced Metering Infrastructure	15.0	-	-	-	-	-	-	-	-	-	-	14.7
Demand Side Management	NA	-	-	-	-	-	-	-	-	-	-	26.1
Customer Care & Marketing Domestic	NA	5.9	6.0	6.1	6.2	6.4	6.5	6.6	6.8	6.9	7.0	122.1
Target Adjustment	NA	(2.4)	(1.8)	(1.9)	(2.0)	(2.1)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(52.5)
		3.5	4.2	4.2	4.3	4.3	4.4	4.5	4.5	4.6	4.7	110.4
GAS CAPITAL SUBTOTAL		30.4	31.6	32.3	32.8	33.5	34.1	34.8	35.5	36.2	36.9	671.9
CONSOLIDATED CAPITAL		1,609.2	1,505.7	1,685.3	998.8	855.6	946.3	1,117.7	1,066.7	995.7	938.6	30,536.8
Target Adjustment	NA	5.3	5.4	5.5	5.6	5.8	5.9	6.0	6.1	6.3	6.4	679.0
CEF11-2 TOTAL		1,614.5	1,511.1	1,690.8	1,004.4	861.4	952.1	1,123.6	1,072.8	1,001.9	945.0	31,215.8

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

c) Please provide a schedule that indicates the amount of cash flow from electric operations, forecast electric base capital spending and net cash flow available to finance Major Generation & Transmission Projects in each of the forecast years and provide the (electric) capital coverage ratio.

[			Y1	Y2 to Y20
Cash Flow from Operations (IFF11-2 Cash Flow Statement)	1			
Base Capital Spending (CEF11)	2			
Net Cash Flow	3	3 = 2-1		
Capital Coverage Ratio	4	4 = 1/2		

The following analysis should agree with the figures presented in IFF11-2 and CEF 11. If not please reconcile.

ANSWER:

Please see the following table.

?) J

	Actuals					Forecast									
For the year ended March 31	2008	2009	2010	2011	2012	2012	2013	2014	2015	2016	2017	2018	2019	2020
1 Cash Flow from Operations	599.0	653.0	528.0	550.0	518.0	434.2	438.6	444.2	446.9	518.9	574.2	563.7	499.2	580.4
2 Base Capital Spending	363.0	359.0	414.0	450.0	472.0	417.4	411.5	394.4	387.3	363.8	372.4	380.4	387.6	396.4
3 Excess Cash Flow after Base Capital Spending (1-2)	236.0	294.0	114.0	100.0	46.0	16.8	27.1	49.8	59.6	155.0	201.8	183.3	111.6	184.0
4 Capital Coverage Ratio (1/2)	1.65	1.82	1.28	1.22	1.10	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46
5 Major New Generation & Transmission	477.4	543.5	679.0	657.5	567.8	656.1	762.6	1060.0	1223.4	1566.9	1610.5	1953.0	1177.1	1412.0
6 Cash Flow required to Finance MNG&T	241.4	249.5	565.0	557.5	521.8	639.4	735.5	1010.1	1163.8	1411.9	1408.7	1769.7	1065.5	1228.0

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1 Cash Flow from Operations	514.1	716.6	832.0	920.9	1065.5	1175.2	1192.2	1294.5	1388.2	1501.2	1597.8	1748.2
2 Base Capital Spending	359.8	385.9	430.2	462.4	522.7	498.6	514.6	503.1	535.9	567.5	478.6	583.7
3 Excess Cash Flow after Base Capital Spending (1-2)	154.3	330.7	401.7	458.5	542.8	676.6	677.6	791.5	852.4	933.7	1119.2	1164.6
4 Capital Coverage Ratio (1/2)	1.43	1.86	1.93	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00
5 Major New Generation & Transmission	1445.8	1306.0	1071.8	933.3	1050.2	385.6	224.1	323.8	460.0	374.9	390.2	225.5
6 Cash Flow required to Finance MNG&T	1291.5	975.3	670.1	474.7	507.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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MANITOBA HYDRO 2011/12 POWER RESOURCE PLAN

Date: August 31, 2011

The purpose of the 2011/12 Power Resource Plan is to provide plans for the long-term power resource development for Manitoba Hydro which include:

- a recommended development plan for use in the 2011 Integrated Financial Forecast and the Capital Expenditure Forecast, and
- alternative development plans, which recognize the uncertainties associated with the recommended plan.

2011/12 Power Resource Development Plan – the Sales Package

The recommended power resource development plan includes the major infrastructure and resources to pursue a new 500 kV US interconnection and facilitate the Minnesota Power (MP) and Wisconsin Public Service sales as follows:

- Keeyask G.S. with a 2019/20 ISD,
- Conawapa G.S. with a 2024/25 ISD,
- A new US interconnection capable of meeting the MP and WPS sales requirements with an earliest ISD of 2019/20,
- The MH-MP Sale Agreements dated May 19, 2011,
- The WPS Sale Agreements dated May 19, 2011,
- A proposed 500 MW Sale to WPS
- A transmission allowance for additional north-south transmission beyond a 2000 MW Bipole III, as required for the combined Conawapa and Keeyask generation with a 2024/25 ISD.

2011/12 Alternative Power Resource Development Plans

Alternative Development Plan 1 – the 250 MW Interconnection Package

The alternative recommended power resource development plan which includes the major infrastructure and resources to pursue a new US interconnection and facilitate the MP sales as follows:

- Keeyask G.S with a 2019/20 ISD,
- Conawapa G.S. with a 2024/25 ISD,
- A new US interconnection capable of 250 MW export and 250 MW import with a 2020/21 ISD,
- The MH-MP Sale Agreements dated May 19, 2011,
- The WPS Sale Agreements dated May 19, 2011,
- A transmission allowance to account for additional north-south transmission beyond a 2000 MW Bipole III, as required for the combined Conawapa and Keeyask generation with a 2024/25 ISD.

Alternative Development Plan 2 – No New Interconnection

In the event that a new US interconnection and/or the Keeyask Project becomes unachievable, the alternative power resource development plan for major infrastructure and resources to meet Manitoba requirements without a new interconnection is as follows:

- Combined Cycle Gas Turbine with a 2021/22 ISD,
- Conawapa G.S. with a 2027/28 ISD

Inherent in these plans are the base resource assumptions, which can be found in Section 3 - Supply of Power. The Supply and Demand Tables for Dependable Energy and Capacity can be found in Appendix A. Supply and Demand Tables for Average Energy for both the recommended and alternative development plans can be found in Appendix B.

Recommended Plan

System Firm Energy Demand and Dependable Resources (GW.h)

2011 Base Load Forecast, 2011 DSM - Option 2

Kelsey Rerunnering, Pointe du Bois rebuild 2030/31, Brandon Unit 5 until 2018/19, Wuskwatim 2011/12, Bipole III Line (West) 2017/18
Supply Includes: Keeyask 2019/20, Conawapa 2024/25, SCGT's starting in 2041/42, 500kV Interconnection in 2019/20
Demand Includes: Potential Sales to Wisconsin Public Service and Minnesota Power

Fiscal Year	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29
Power Resources																		
Existing Manitoba Hydro Plants	20740	20720	20700	20690	20680	20660	20640	20630	20610	20600	20590	20580	20580	20570	20560	20560	20550	20540
Hydro Adjustment	340	340	340	340	240	240	240	240	240	240	240	240	240	240				
Existing Hydro NET	21080	21060	21040	21030	20920	20900	20880	20870	20850	20840	20830	20820	20820	20810	20560	20560	20550	20540
New Hydro																		
Wuskwatim	75	1205	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250	1250
Conawapa														2151	4550	4550	4550	4550
Keeyask									677	2898	2903	2903	2903	2903	2903	2903	2903	2903
Supply Side Enhancement Projects																		
Kelsey Rerunnering																		
Pointe du Bois Rebuild																		
Bipole III HVDC Line NET							243	243	243	258	258	258	258	258	162	162	162	162
Manitoba Thermal Plants																		
Brandon Unit 5	811	811	811	811	811	811	811	811										
Selkirk Gas	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCGT	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354	2354
New Thermal Plants																		
SCGT																		
Committed Wind	770	819	819	819	819	819	819	819	819	819	819	819	819	819	819	819	819	819
New Wind																		
Demand Side Management	183	293	411	508	608	696	699	774	830	882	911	944	971	996	1009	967	947	924
Imports																		
Contracted Energy Imports	2705	2705	2705	2705	1609	1614	1614	1614	1614	2527	2710	2710	2710	2710	1363	1096	1096	1096
Proposed Energy Imports															1460	1753	2118	2192
Non-Contracted Energy Imports					1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1446	1575	1575	1575
Total Power Resources	28931	30200	30343	30430	30424	30497	30723	30788	30690	33881	34088	34111	34138	36304	38830	38942	39277	39318
Demand																		
2011 Base Load Forecast	24615	25173	25930	26284	26406	26794	27205	27481	27966	28462	28887	29311	29733	30153	30570	30984	31396	31801
Non-Committed Construction Power			10	25	50	60	85	105	80	75	55	80	100	90	40	25	30	30
Exports																		
Current Exports	3584	3293	3156	3156	2115	2012	2012	2012	2012	3064	3695	3780	3780	3780	2017	1913	1492	1408
Proposed Exports															1683	2020	2441	2525
Less Adverse Water	-91	-91			-309	-370	-370	-370	-370	-370	-370	-370	-370	-370	-61			
Total Demand	28108	28374	29096	29465	28263	28495	28931	29227	29687	31230	32267	32801	33242	33653	34249	34942	35359	35764
System Surplus	823	1826	1246	965	2162	2002	1792	1561	1003	2651	1821	1310	895	2651	4581	4000	3918	3554
Less: Brandon Unit 5	811	811	811	811	811	811	811	811										
Adverse Water Energy	91	91			309	370	370	370	370	370	370	370	370	370	61			
Exportable Surplus		924	435	154	1042	821	610	380	633	2281	1451	939	525	2280	4520	4000	3918	3554

Recommended Plan

System Supply & Demand Balance (GW.h) at North

Under Average of all Flow Conditions

2011 Base Load Forecast, 2011 DSM - Option 2

Kelsey Rerunnering, Pointe du Bois rebuild 2030/31, Wuskwatim 2012/13, Bipole III Line 2017/18 (West)
Supply Includes: Keeyask 2019/20, Conawapa 2024/25, SCGTs starting in 2041/42, 500kV Interconnection in 2019/20
Demand Includes: Potential Sales to Wisconsin Public Service and Minnesota Power

Fiscal Year	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Power Resources																	
Hydro Generation	30744	30711	30693	30698	30460	30376	30813	33223	34587	34816	34757	36491	40442	41710	41676	41636	41637
Bipole III					392	392	392	315	315	315	315	315	27	27	27	27	27
Thermal Generation	341	359	343	355	416	457	324	338	330	340	337	334	276	289	307	302	304
Committed Wind	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963
Demand Side Management	411	508	608	696	699	774	830	882	911	944	971	996	1009	967	947	924	911
Imports	1420	1516	1494	1542	1625	1673	1937	1923	1791	1818	1953	1902	1856	2042	2160	2232	2307
Total Power Resources	**33878**	**34056**	**34100**	**34254**	**34554**	**34835**	**35259**	**37645**	**38898**	**39195**	**39295**	**41000**	**44573**	**45998**	**46080**	**46083**	**46148**
Demand																	
2011 Base Load Forecast	25930	26284	26406	26794	27205	27481	27966	28462	28887	29311	29733	30153	30570	30984	31396	31801	32208
Non-Committed Construction Power	10	25	50	60	85	105	80	75	55	80	100	90	40	25	30	30	35
Current Exports (with MP 250 MW sale)	3307	3307	2265	2161	2161	2161	2161	3500	4139	4213	4213	4213	2081	1902	1902	1902	1737
Proposed Exports													2142	2571	3107	3214	3214
Total Demand	**29247**	**29616**	**28721**	**29015**	**29451**	**29747**	**30207**	**32036**	**33081**	**33605**	**34046**	**34456**	**34833**	**35482**	**36435**	**36947**	**37194**
Exportable System Surplus	**4630**	**4442**	**5379**	**5239**	**5103**	**4888**	**5052**	**5608**	**5817**	**5590**	**5249**	**6544**	**9740**	**10515**	**9645**	**9136**	**8954**

Fiscal Year	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47
Power Resources																	
Hydro Generation	41837	41908	41938	41940	41936	41917	41927	41932	41929	41936	41926	41931	41924	41923	41935	41941	41911
Bipole III	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Thermal Generation	304	303	304	302	302	261	243	219	192	168	167	246	340	453	568	688	724
Committed Wind	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963	963
Demand Side Management	894	889	889	888	885	887	878	868	858	858	858	858	858	858	858	858	858
Imports	2344	2398	2446	2505	2562	2478	2465	2530	2547	2493	2596	2663	2751	2824	2822	2881	3011
Total Power Resources	**46368**	**46488**	**46567**	**46624**	**46675**	**46533**	**46504**	**46538**	**46514**	**46444**	**46536**	**46687**	**46882**	**47048**	**47173**	**47357**	**47492**
Demand																	
2011 Base Load Forecast	32608	33009	33409	33809	34209	34610	35010	35410	35811	36211	36611	37012	37412	37812	38213	38613	39013
Non-Committed Construction Power	30	10															
Current Exports (with MP 250 MW sale)	1704	1704	1704	1704	1704	365	97	97	97	97	97	97	97	97	97	97	97
Proposed Exports	3214	3214	3214	3214	3214	3214	2679	2036	1125	161							
Total Demand	**37557**	**37937**	**38327**	**38728**	**39128**	**38190**	**37786**	**37543**	**37033**	**36469**	**36708**	**37109**	**37509**	**37909**	**38310**	**38710**	**39110**
Exportable System Surplus	**8811**	**8551**	**8239**	**7896**	**7547**	**8343**	**8718**	**8995**	**9481**	**9975**	**9828**	**9578**	**9354**	**9139**	**8863**	**8648**	**8382**

C. RESOURCE OPTIONS SUMMARY TABLE

	Resource Option	Nominal Capacity (MW)	Flow Related Energy (GW.h)	
			Dependable	Average
Conventional Hydro	Notigi GS	100	585	750
	Manasan GS (High Head)	265	1070	1670
	First Rapids GS	210	890	1400
	Kelsey GS Extension	120	N/A	425
	Birthday GS	320	2100	2100
	Keeyask GS	695	2900	4430
	Conawapa GS	1485	4550	7000
	Gillam Island GS	1000	3150	5040
	Whitemud GS	310	1360	1700
	Red Rock GS (Low Head)	250	N/A	N/A
	Bonald GS	120	N/A	N/A
	Granville GS	125	N/A	N/A
Other Hydro	Run-of-River Hydro	1 to 50	5 to 230	5 to 230
	Kinetic Hydro	1 to 100	8 to 790	8 to 790
Wind	On-Shore Wind	70	193 to 209	227 to 245
Solar	Photovoltaic (Utility Plant Scale)	1 to 300	0 to 265	0 to 265
Geo.	Enhanced Geothermal System	10 to 50	85 to 415	85 to 415
Gas	Simple Cycle Gas Turbine	51	437	65 to 110
	Combined Cycle Gas Turbine	310	2636	1300 to 1750
	Blended Gas Turbine	50	427	100 to 140
Coal	Pulverized Coal Generation	400	2980	NA
	Integrated Gasification Combined Cycle	640	4490	NA
Nu.	Nuclear Power Plant	1350	10650	10650
Biomass	Agricultural Crop Residue	30	225	225
	Wood Waste	20	150	150
DSM	Additional DSM	256	1008	1008
Imp.	Contractual Import Agreements	N/A	N/A	N/A

Table 3: **Changes to Supply-Demand Balances in the Last Three Years**

Changes to Supply-Demand System Surplus in the Last Three Years 2009/10, 2010/11 and 2011/12															
	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Dependable Energy (GWh)															
2009/10	1686	2155	1823	1231	3175	2596	2350	1935	785	452	120	-227	-562	-938	-1354
2010/11	1353	1888	1350	1252	2213	1910	1897	1637	470	125	-218	-570	-925	-1302	-1525
2011/12	**823**	**1826**	**1256**	**990**	**2212**	**2062**	**1877**	**1666**	**406**	**-48**	**-454**	**-856**	**-1251**	**-1656**	**-1866**
Winter Peak Capacity (MW)															
2009/10	792	823	702	594	1264	1003	1053	765	352	290	228	165	101	31	-53
2010/11	617	642	493	457	420	356	398	345	175	110	45	-21	-89	-160	-287
2011/12	**448**	**625**	**447**	**395**	**389**	**327**	**343**	**291**	**102**	**17**	**-65**	**-146**	**-226**	**-305**	**-413**

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PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

a) Please provide a schedule that details all payments to municipalities and the Province by year for the fiscal years 2004 through 2032

ANSWER:

Please see the following schedule for all payments to municipalities and the Province for 2008 through 2032.

Payments to the Province and Municipalities (Millions)

Fiscal Year Ended	Water Rentals	Provincial Guarantee Fee	Sinking Fund Admin. Fee	Capital Taxes	Payroll Taxes	Provincial Mitigation or Settlement Obligations (1)	Municipal GILT and Business Taxes	Gross Electricity Operations Revenue	Gross Export Revenue	Total Provincial Payments (GILT & Business Tax Not Included)	Provincial Payments as a Percentage of Gross Revenue
2008	$ 117	$ 70	$ 1	$ 39	$ 8	$ 2	$ 11	$ 1,712	$ 625	$ 236	14%
2009	115	70	1	44	9	0	11	1,771	623	$ 240	14%
2010	114	72	1	46	9	0	20	1,583	427	$ 242	15%
2011	114	77	-	48	10	0	20	1,616	398	$ 249	15%
2012	111	82	-	52	10	1	21	1,573	363	$ 256	16%
2013	98	91	-	54	10	9	22	1,677	341	$ 262	16%
2014	103	100	-	58	11	0	23	1,762	363	$ 271	15%
2015	103	109	-	64	11	0	25	1,857	394	$ 286	15%
2016	103	122	-	71	11	0	25	1,990	469	$ 306	15%
2017	103	138	-	79	11	0	26	2,097	502	$ 331	16%
2018	102	154	-	88	12	0	26	2,206	531	$ 356	16%
2019	101	175	-	93	12	0	27	2,302	554	$ 381	17%
2020	103	184	-	100	12	0	27	2,448	611	$ 399	16%
2021	111	197	-	106	12	0	28	2,751	821	$ 426	16%
2022	116	211	-	112	13	0	28	2,938	913	$ 451	15%
2023	116	219	-	117	13	0	29	3,054	931	$ 465	15%
2024	116	228	-	121	13	0	30	3,173	946	$ 478	15%
2025	122	235	-	126	13	0	30	3,425	1,124	$ 496	14%
2026	135	244	-	127	14	0	31	3,786	1,408	$ 520	14%
2027	139	240	-	127	14	0	31	3,988	1,526	$ 521	13%
2028	139	240	-	128	14	0	32	4,089	1,544	$ 522	13%
2029	139	240	1	129	15	0	33	4,170	1,539	$ 524	13%
2030	139	240	1	130	15	0	34	4,261	1,544	$ 524	12%
2031	140	237	1	130	15	0	34	4,371	1,565	$ 523	12%
2032	140	230	1	130	15	0	35	4,474	1,574	$ 516	12%

(1) Hydro entered into an agreement with the Province whereby the Corporation assumed obligations of the Province with respect to certain northern development projects. Obligations totaling $143 million were assumed, with respect to which water rental charges had been fixed until March 31, 2001. Of these obligations, $9 million remain to be paid in fiscal 2013 and future years.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

b) Please provide a schedule that details the calculation of the debt guarantee fee for the fiscal years 2004 through 2012 and forecast for 2013 and 2014.

ANSWER:

Please see the following table:

Provincial Debt Guarantee Fee (PGF) Calculations
($ millions CAD)

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014
Long Term Debt Balance for PGF	7,160	7,486	8,132	8,538	8,528	9,434	10,274
Short Term Debt Balance for PGF	148	-	100	-	-	48	55
Trust Investment from Pre-Financing		(122)	(166)	(554)	-	-	-
Debt Balance for PGF Purposes	7,308	7,364	8,066	7,984	8,528	9,482	10,330
PGF Rate	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Amount PGF Paid to Province	73	74	76	80	85	95	103
PGF Portion Allocated to Centra	(3)	(3)	(3)	(3)	(3)	(4)	(4)
Net Hydro PGF	70	70	72	77	82	91	100

Notes: (1) The fee calculation is based on ending debt balances at March 31 of the prior fiscal year. Manitoba Hydro is not assessed the provincial debt guarantee fee on bonds issued for mitigation purposes. The fiscal year debt balances presented in PUB/MH I-49(b) represent that amount of debt upon which the PGF was paid or is payable for that fiscal year.

(2) The PGF on US debt is paid in US dollars using the stated PGF rate. For presentation purposes, US debt balances are translated to a Canadian equivalent using the year end exchange rate. The presentation of the US long term debt balance at March 31, 2009 was translated at the year end exchange rate of 1.2602 although the US dollar PGF payment was made at a 1.05036 exchange rate utilizing FX forward contracts. Therefore, the Canadian equivalent of the amount paid to the Province for 2010 was less than 1%. The forecasted year end exchange rates for 2012, 2013 and 2014 were 0.98, 0.99 and 0.99 respectively.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

c) Please provide a schedule that details the calculation of water rental payments for the fiscal years 2004 through 2012 and forecast for 2013, and 2014.

ANSWER:

Please see the following schedule for the water rental payment calculation for the years 2008 through 2014.

Water Rental Calculation

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Forecast 2013	Forecast 2014	
Megawatt-Hours Generated (billion kWh)	34.9	34.2	33.8	34.0	33.2	29.3	30.7	
Converted to Horsepower-years (million HP-YR)	5.7	5.6	5.6	5.6	5.5	4.8	5.1	(1)
Rental Rate per Horsepower-year	$ 20.32	$ 20.32	$ 20.32	$ 20.32	$ 20.32	$ 20.32	$ 20.32	(2)
Calculated Water Annual Rental ($ million)	$ 116.7	$ 114.3	$ 113.0	$ 113.8	$ 110.8	$ 97.8	$ 102.7	
Minimum Rental Adjustment		0.2	1.0	0.3				(3)
Other Adjustment	0.3							(4)
Total Water Rentals	$ 117.0	$ 114.5	$ 114.0	$ 114.1	$ 110.8	$ 97.8	$ 102.7	

(1) The Water Power Act defines "Horsepower-year" as kW.h/6535 X 1.075.

(2) The water rental fee was calculated at a rate of 9.90 per Horsepower-year generated up to March 31, 2001. Effective April 1, 2001 the rate was increased to its current level of $20.32 per Horsepower-year.

(3) The Water Power Act of Manitoba provides that the water rentals charged for each generation site be the greater of (a) a fixed rate multiplied by the installed capacity of that site and (b) a fixed rate multiplied by the electrical output for the year of that site. Generally, the calculation under (b) based on actual output results in the greatest amount for each generation site. In some years, such as 2009 it is necessary to adjust the amounts calculated under the (b) calculation for some specific sites to bring the total up to the amount calculated under the (a) installed capacity calculation method.

(4) Due to a rounding difference.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

d) Please provide a schedule that details all forecast payments to all Government by year from 2013 to 2032.

ANSWER:

Please see the response to PUB/MH I-49(a) for the forecast payments to municipalities and the Province for the years 2013 to 2032.

The only significant payments to the federal government are in the form of the employer premiums for Canada Pension Plan (CPP) and Employment Insurance (EI). For forecasting purposes these payments are included in the general employee benefit amount applied to salaries and are not forecasted as separate amounts.

The actual payments made for fiscal 2012 were $14.2 million for CPP premiums and $6.5 million for EI premiums.

PUB/MH I-49

Reference: Tab 5 25 & 31 of 36 Payments to Governments

e) **Please provide an update to the table in PUB/MH II-14 (a) adding the years 2025 and 2032.**

ANSWER:

Please see Manitoba Hydro's response to PUB/MH I-49(a).

PUB/MH I-71

Reference: **Tab 5 Section 5.1o Page 31 of 36Capital Taxes**

Please provide the details of the taxable paid up capital balance for Manitoba capital tax purposes for the fiscal years 2011, and 2012 and the projected taxable capital for the fiscal years 2013 through 2014.

ANSWER:

Please see the following table for capital tax information for the years 2011 through 2014.

Taxable Paid Up Capital Calculation:
($ Billions)

	Actual 2011	**Actual 2012**	**Forecast 2013**	**Forecast 2014**
Total Debt	8.9	9.6	10.6	11.4
Retained Earnings	2.4	2.5	2.4	2.2
AOCI	0.4	0.3	0.3	0.1
Total Paid Up Capital (A)	11.6	12.4	13.3	13.7
Temporary Investments	0.1	0.0	0.0	0.0
Sinking Fund Assets	0.3	0.3	0.3	0.1
Pension Investments	0.8	0.8	0.8	0.5
Investment in Subsidiaries	0.3	0.3	0.2	0.2
Loans to Subsidiaries	0.9	1.0	1.3	1.3
Total Eligible Assets (B)	2.3	2.5	2.7	2.2
Total Assets (C)	14.0	15.0	14.4	14.4
Total Paid Up Capital	11.6	12.4	13.3	13.7
Less Investment Allowance (B/C X A)	1.9	2.0	2.5	2.1
Taxable Paid Up Capital	9.7	10.4	10.9	11.6
Capital Tax Calculation ($ millions)				
Capital Tax at 0.5% X D	48	52	54	58

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PUB/MH I-134

Reference: **2010 GRA – WPLP Agreement/2011 GRA – PUB/MH II-38/PUB/MH I-42 Wuskwatim Partnership (WPLP)**

Please re-file PUB/MH II-38 and PUB/MH I -142 updated and provide a detailed illustration of WPLP revenue calculation process including 2013/14 components of:

a) **Contract sales and prices (if applicable)**
b) **Opportunity peak sales and prices**
c) **Opportunity off-peak sales and prices**
d) **Domestic sales and prices (if applicable)**

ANSWER:

Please see the attached schedules for updates to PUB/MH II-38 and PUB/MH I-42 from the 2010/11 & 2011/12 General Rate Application.

Wuskwatim's revenue related to energy generated during the on-peak hours is determined based on the average price Manitoba Hydro realizes for long-term export sales and import transactions. Wuskwatim's revenue related to energy generated during the off-peak hours is determined from the average price Manitoba Hydro realizes for all on-peak and off-peak opportunity export and import transactions, excluding the on-peak long-term transactions. The total of gross revenue related to on-peak and off-peak energy is reduced by transmission and related market participation charges and Manitoba Hydro's 3% marketing risk fee.

The WPLP revenue calculation cannot be broken down further as requested as contract and opportunity sales and prices are commercially sensitive information. Domestic sales are not included in the determination of the WPLP revenue.

Please note that the WPLP projected financial statements were prepared assuming a March 2012 in-service date for the first generating unit and the electric operations forecast was subsequently adjusted to reflect the deferral to June 2012 for the finalization of IFF11-2.

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
REVENUES											
Revenue	1	57	57	69	90	99	108	117	124	125	133
	1	57	57	69	90	99	108	117	124	125	133
EXPENSES											
Operating and Administrative	1	10	10	10	10	10	10	10	10	11	11
Finance Expense	3	62	71	73	75	74	73	72	70	68	66
Depreciation and Amortization	1	23	25	25	25	25	25	25	25	25	25
Water Rentals and Assessments	0	5	5	5	5	5	5	5	5	5	5
	5	99	110	113	115	114	113	112	110	109	106
Net Income	(3)	(42)	(54)	(44)	(25)	(15)	(5)	5	14	17	27
Financial Ratios											
Debt	75%	78%	82%	85%	85%	85%	85%	84%	83%	81%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
REVENUES										
Revenue	139	141	147	143	146	151	155	159	164	168
	139	141	147	143	146	151	155	159	164	168
EXPENSES										
Operating and Administrative	11	11	12	12	12	11	11	11	12	12
Finance Expense	61	60	59	58	57	56	55	54	53	52
Depreciation and Amortization	25	25	25	25	25	25	25	25	25	25
Water Rentals and Assessments	5	5	5	5	5	5	5	5	5	5
	102	101	101	100	99	98	96	96	95	94
Net Income	36	40	46	43	47	53	58	64	69	74
Financial Ratios										
Debt	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ASSETS										
Plant in Service	446	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337	1,337
Accumulated Depreciation	(1)	(17)	(36)	(55)	(74)	(93)	(111)	(130)	(149)	(168)
Net Plant in Service	445	1,319	1,300	1,282	1,263	1,244	1,225	1,207	1,188	1,169
Construction in Progress	821	(6)	0	0	0	0	0	0	0	0
Current and Other Assets	297	299	303	308	315	321	329	336	345	353
	1,563	1,612	1,604	1,590	1,577	1,566	1,554	1,543	1,532	1,522
LIABILITIES AND EQUITY										
Long-Term Debt	800	998	1,052	1,102	1,102	1,102	1,102	1,102	1,102	1,102
Current and Other Liabilities	450	327	316	297	285	278	272	255	231	204
Partners Capital	314	287	235	191	190	185	180	185	199	216
	1,563	1,612	1,604	1,590	1,577	1,566	1,554	1,543	1,532	1,522

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
ASSETS										
Plant in Service	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340
Accumulated Depreciation	(206)	(224)	(243)	(262)	(281)	(300)	(319)	(338)	(357)	(375)
Net Plant in Service	1,134	1,116	1,097	1,078	1,059	1,040	1,021	1,003	984	965
Construction in Progress	0	0	0	0	0	0	0	0	0	0
Current and Other Assets	373	384	395	407	420	433	448	463	479	496
	1,507	1,499	1,492	1,485	1,479	1,474	1,469	1,466	1,463	1,461
LIABILITIES AND EQUITY										
Long-Term Debt	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102
Current and Other Liabilities	151	141	143	140	141	144	146	149	153	158
Partners Capital	254	256	246	243	235	228	221	214	208	201
	1,507	1,499	1,492	1,485	1,479	1,474	1,469	1,466	1,463	1,461

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
OPERATING ACTIVITIES											
Cash Receipts from Customers	1	57	57	69	90	99	108	117	124	125	133
Cash Paid to Suppliers and Employees	(1)	(15)	(15)	(15)	(15)	(16)	(16)	(15)	(16)	(16)	(16)
Interest Paid	(39)	(66)	(71)	(74)	(76)	(76)	(75)	(75)	(74)	(72)	(71)
Interest Received	-	-	0	1	1	2	2	3	4	4	5
	(39)	(24)	(29)	(19)	0	10	20	30	39	42	52
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	200	-	50	50	-	-	-	-	-	-	-
Other	42	15	0	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
	242	15	50	49	(1)	(1)	(1)	(2)	(2)	(2)	(2)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(133)	(60)	(6)	-	-	(0)	-	-	-	-	(0)
Sinking Fund Payment	-	(8)	(10)	(11)	(12)	(13)	(13)	(14)	(14)	(15)	(15)
Other	-	198	4	-	-	23	10	-	-	-	-
	(133)	130	(12)	(11)	(12)	11	(3)	(14)	(14)	(15)	(16)
Net Increase (Decrease) in Cash	71	122	10	18	(13)	19	15	15	23	25	34
Cash at Beginning of Year	(223)	(152)	(31)	(21)	(3)	(16)	3	18	33	56	81
Cash at End of Year	(152)	(31)	(21)	(3)	(16)	3	18	33	56	81	115

WUSKWATIM POWER LIMITED PARTNERSHIP (IFF11-2)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
OPERATING ACTIVITIES										
Cash Receipts from Customers	139	141	147	143	146	151	155	159	164	168
Cash Paid to Suppliers and Employees	(16)	(16)	(17)	(17)	(17)	(16)	(16)	(16)	(17)	(17)
Interest Paid	(67)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)	(66)
Interest Received	6	6	7	8	9	9	10	11	12	13
	61	65	71	68	71	78	83	89	94	99
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	-	-	-	-	-	-	-	-	-	-
Other	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)
	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(3)	-	-	-	(0)	-	-	-	-	(0)
Sinking Fund Payment	(16)	(17)	(17)	(18)	(19)	(20)	(20)	(21)	(22)	(23)
Other	44	(70)	(38)	(56)	(46)	(54)	(61)	(65)	(71)	(76)
	25	(86)	(55)	(75)	(65)	(73)	(81)	(86)	(93)	(99)
Net Increase (Decrease) in Cash	84	(23)	14	(9)	4	2	(0)	(1)	(2)	(3)
Cash at Beginning of Year	115	199	176	189	181	184	186	186	185	184
Cash at End of Year	199	176	189	181	184	186	186	185	184	181

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST OM&A COSTS
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Operating and Administrative											
Generating Station O&A	1	9	9	9	9	9	9	9	9	9	10
Transmission Related O&A	0	0	0	0	0	1	1	1	1	1	1
Development Fund	-	1	1	1	1	1	1	1	1	1	1
	1	10	10	10	10	10	10	10	10	11	11

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST OM&A COSTS
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operating and Administrative										
Generating Station O&A	10	10	10	10	11	10	10	10	10	10
Transmission Related O&A	1	1	1	1	1	1	1	1	1	1
Development Fund	1	1	1	1	1	1	1	1	1	1
	11	11	12	12	12	11	11	11	12	12

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FINANCE EXPENSE FORECAST
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Finance Expense											
Interest on Long Term Debt	36	48	53	56	59	60	60	60	60	60	60
Interest on Short Term Debt	2	1	1	1	0	(0)	(1)	(2)	(3)	(4)	(5)
Interest on Interconnection Credit Facility	1	17	17	17	16	16	16	16	16	16	16
Sinking Fund Admin Fee	-	-	0	0	0	0	0	0	0	0	0
Interest Income	-	-	(0)	(1)	(1)	(2)	(2)	(3)	(4)	(4)	(5)
Capitalized Interest	(37)	(4)	-	-	-	(0)	-	-	-	-	(0)
	3	62	71	73	75	74	73	72	70	68	66

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FINANCE EXPENSE FORECAST
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Finance Expense										
Interest on Long Term Debt	60	60	60	60	60	60	60	60	60	60
Interest on Short Term Debt	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Interest on Interconnection Credit Facility	16	16	16	15	15	15	15	15	15	15
Sinking Fund Admin Fee	0	0	0	0	0	0	0	0	0	0
Interest Income	(6)	(6)	(7)	(8)	(9)	(9)	(10)	(11)	(12)	(13)
Capitalized Interest	(0)	-	-	-	(0)	-	-	-	-	(0)
	61	60	59	58	57	56	55	54	53	52

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INTEREST RATES
(In Millions of Dollars)

For the year ended March 31	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Short Term Debt Interest Rate w/ PGF	1.90%	2.25%	3.20%	4.80%	5.05%	5.25%	5.30%	5.30%	5.30%	5.30%	5.30%
Long Term Debt Interest Rate w/ PGF	4.75%	4.70%	5.05%	6.40%	6.90%	7.20%	7.40%	7.40%	7.40%	7.40%	7.40%
Equity Loan Credit Facility Interest Rate	2.90%	3.25%	6.05%	7.40%	7.90%	8.20%	8.40%	8.40%	8.40%	8.40%	10.40%

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST INTEREST RATES
(In Millions of Dollars)

For the year ended March 31	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Short Term Debt Interest Rate w/ PGF	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
Long Term Debt Interest Rate w/ PGF	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Equity Loan Credit Facility Interest Rate	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST REVENUE
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Average Generation (GW.h)	41	1,469	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Wuskwatim Revenue	2	59	58	71	93	102	112	121	128	129	138
Marketing Risk Fee	(0)	(2)	(2)	(2)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Wuskwatim Net Revenue	1	57	57	69	90	99	108	117	124	125	133
Average Price ($/MW.h) net of Risk Fee	35.98	38.79	37.29	45.38	59.45	65.49	71.42	77.22	81.95	82.71	87.99

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST REVENUE
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Average Generation (GW.h)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Wuskwatim Revenue	143	146	151	147	150	155	160	164	169	174
Marketing Risk Fee	(4)	(4)	(5)	(4)	(5)	(5)	(5)	(5)	(5)	(5)
Wuskwatim Net Revenue	139	141	147	143	146	151	155	159	164	168
Average Price ($/MW.h) net of Risk Fee	91.40	93.08	96.78	94.28	96.10	99.33	102.04	104.98	107.98	110.97

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST WATER RENTALS
(In Millions of Dollars)

For the year ended March 31	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Average Generation (GW.h)	41	1,469	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Water Rental Rate ($/MW.h)	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341
Water Rentals	0	5	5	5	5	5	5	5	5	5	5

WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)
FORECAST WATER RENTALS
(In Millions of Dollars)

For the year ended March 31	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Average Generation (GW.h)	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517	1,517
Water Rental Rate ($/MW.h)	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341	3.341
Water Rentals	5	5	5	5	5	5	5	5	5	5

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CAC/MH I-15

Subject: **Integrated Financial Forecast**
Reference: **Tab 4, Page 4**

a) **For each of MH09-1; MH10-2 and MH11-2 please indicate the annual impact of Wuskwatim on the operating statement through to the year 2013/14.**

ANSWER:

Please see the attached schedule.

Estimated Impacts of Wuskwatim on Net Income
($Millions)

	IFF09		IFF10		IFF11-2	
Projected capital cost of Wuskwatim (Including Transmission)	1,591		1,566		1,672	
	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14
Finance expense (net of internally generated funds)	61	62	61	61	65	71
OM&A costs	6	6	7	8	8	10
Depreciation	27	27	23	26	23	25
Capital tax and water rentals	10	10	10	10	10	11
Income statement impacts *	104	105	101	105	106	117

* Before non-controlling interest

Exhibit # MH-115
Transcript Pages #4487 &
#4489-4490

<u>Manitoba Hydro Undertaking #93</u>

Manitoba Hydro to provide calculation for the $4 million amount shown for 2012. Update the Income Statement for the Wuskwatim Limited Partnership Agreement for IFF10. To the extent we filed the balance sheet and cash flow statement, update those for IFF10 as well.

The non-controlling interest in 2011/12 of $4 million represents Nisichawayasihk Cree Nation's 33% share of the Wuskwatim Power Limited Partnership's (WPLP) projected $13 million loss in the year.

The WPLP projected financial statements corresponding to IFF10 are attached.

The Income Statement impacts of Wuskwatim in 2012/13 (the first full year of operation) can be calculated as follows:

Projected capital cost of Wuskwatim	$	1,566	million
Internally generated funds (35%)		(548)	
Long term borrowing requirements	$	1,018	
First year long term financing cost @ 6%	$	61	
OM&A costs		7	
Depreciation @ 1.5%		23	
Capital tax and water rentals		10	
Income statement impacts (first year)	$	101	
Income statement net cost per kW.h:			
$101 / 1515 GW.h =		6.7	¢/kW.h
Assumed revenue per kW.h		5.5	
Net loss per kW.h		1.2	
First year loss: 1515 GW.h * 1.2¢/kW.h =	$	18	million

WUSKWATIM POWER LIMITED PARTNERSHIP
PROJECTED OPERATING STATEMENT
IFF10
(In Millions of Dollars)

For the year ended March 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES										
Revenue	-	27	88	94	104	114	121	127	134	142
	-	27	88	94	104	114	121	127	134	142
EXPENSES										
Operating and Administrative	-	4	8	8	8	8	8	8	8	8
Finance Expense	-	24	66	66	65	63	60	59	57	56
Depreciation and Amortization	-	10	26	26	26	26	27	27	27	27
Water Rentals and Assessments	-	2	5	5	5	5	5	5	5	5
	-	40	106	105	104	103	100	99	97	96
Net Income/(Loss)	-	(13)	(18)	(11)	(1)	12	20	29	37	46

WUSKWATIM POWER LIMITED PARTNERSHIP
PROJECTED BALANCE SHEET
IFF10
(In Millions of Dollars)

For the year ended March 31	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ASSETS										
Plant in Service	-	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240
Accumulated Depreciation	-	(6)	(25)	(43)	(62)	(80)	(99)	(117)	(136)	(154)
Net Plant in Service	-	1,234	1,216	1,197	1,178	1,160	1,142	1,123	1,105	1,086
Construction in Progress	1,103	(16)	-	-	-	-	-	-	-	-
Current and Other Assets	270	287	289	290	292	295	298	301	305	309
	1,373	1,505	1,504	1,487	1,471	1,455	1,439	1,424	1,409	1,395
LIABILITIES AND EQUITY										
Long-Term Debt	800	918	930	930	930	930	930	930	930	930
Current and Other Liabilities	297	294	294	288	272	245	241	233	227	221
Equity	276	293	279	269	268	280	268	261	252	244
	1,373	1,505	1,504	1,487	1,471	1,455	1,439	1,424	1,409	1,395

WUSKWATIM POWER LIMITED PARTNERSHIP
PROJECTED CASH FLOW STATEMENT
IFF10
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPERATING ACTIVITIES										
Cash Receipts from Customers	-	(27)	(88)	(94)	(104)	(114)	(121)	(127)	(134)	(142)
Cash Paid to Suppliers and Employees	-	6	13	13	13	13	14	14	13	13
Interest Paid	33	53	66	66	66	65	63	62	61	60
Interest Received	-	-	-	(0)	(1)	(2)	(3)	(3)	(4)	(5)
	33	32	(9)	(16)	(26)	(38)	(47)	(55)	(64)	(72)
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	(400)	(118)	(12)	-	-	-	-	-	-	-
Proceeds from Issue of Units	(73)	(30)	(4)	-	-	-	-	-	-	-
Other	-	1	1	1	1	1	1	1	2	2
	(473)	(148)	(15)	1	1	1	1	1	2	2
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	258	92	16	-	-	0	-	-	-	-
Sinking Fund Payment	-	-	9	10	10	10	11	11	12	12
Other	-	-	-	-	-	-	-	32	36	46
	258	92	25	10	10	11	11	43	48	58
Net Increase (Decrease) in Cash	(182)	(24)	1	(5)	(15)	(26)	(34)	(10)	(15)	(13)
Cash at Beginning of Year	209	27	3	5	(0)	(15)	(41)	(76)	(86)	(100)
Cash at End of Year	27	3	5	(0)	(15)	(41)	(76)	(86)	(100)	(113)

PUB/MH II-50

Reference: PUB/MH I-39 (a), PUB/MH I-134,CAC/MH I-15 (a)

b) Please indicate the total internally generated funds assumed to be used for this project. Provide detailed calculations in support of the estimate.

ANSWER:

Please see the attached schedule.

Manitoba Hydro

Analysis of Wuskwatim Project Sources and Uses of Cash Flows

Based on actuals available to March 31, 2011 and forecast based on IFF11-2

			Total	2012/13	2011/12	2010/11	2009/10	2008/09	2007/08	2006/07	2005/06	2004/05	2003/04 & Prev.
1	Total Capital Expenditures		8,132	1,244	1,114	1,134	1,117	932	869	680	522	520	
2	Less Total Base Capital		(3,659)	(453)	(458)	(477)	(438)	(388)	(391)	(383)	(311)	(361)	
3	**Total MNG&T Capital**	(2 -1)	**4,473**	**791**	**656**	**657**	**679**	**544**	**478**	**297**	**211**	**159**	
4	Total Wuskwatim Capital (Generation & Transmission)		1,672	71	213	326	367	254	207	77	36	36	85
5	% Total Wuskatim Capital/ Total MNG&T Capital	(4 / 3)	37%	9%	32%	50%	54%	47%	43%	26%	17%	23%	
6	Cash Flow from Operations		5,032	537	427	572	589	688	633	443	710	433	
7	Less Total Base Capital		(3,659)	(453)	(458)	(477)	(438)	(388)	(391)	(383)	(311)	(361)	
8	**Total Surplus Cash Flow from Operations for MNG&T Capital**	(6 - 7)	**1,373**	**84**	**(31)**	**95**	**151**	**300**	**242**	**60**	**399**	**72**	
9	Total Surplus Cash Flow from Operations Attributed to Wuskwatim Capital	(5 * 8)	481	8	-	47	82	140	105	16	68	16	-
10	Total Financing Activities Attributed to Wuskwatim Capital		1,191	64	213	279	285	114	102	61	(32)	20	85
11	**Total Wuskwatim Capital** (Generation & Transmission)		**1,672**	**71**	**213**	**326**	**367**	**254**	**207**	**77**	**36**	**36**	**85**
12	**Total IGF Allocated to Wuskwatim/Total Wuskwatim Capital Cost**	(9 / 10)	**29%**	**29%**	**30%**	**34%**	**40%**	**50%**	**46%**	**43%**	**54%**	**13%**	**0%**

PUB/MH I-45

Reference: 2012 Annual Report & 2011 Annual Report, Note 6, Page 80

With respect to the Construction in Progress balances outlined in note 6 to the financial statements, please provide the following:

a) Describe MH's policy for capitalizing Construction in Progress costs and how the policy has changed as a result of IFRS.

ANSWER:

Manitoba Hydro capitalizes all project costs related to asset additions, including direct labour, materials, contracted services, a proportionate share of overhead costs and interest applied at the average cost of debt. Capital project costs are charged to Construction Work in Progress until the corresponding asset becomes available for use, at which time the transfer to in-service property plant and equipment is made, interest expense allocated to construction ceases, and depreciation and finance expense charged to operations commences.

Overall, MH's policy for capitalizing construction in progress costs is not expected to change as a result of IFRS. However some of the costs eligible for capitalization will change upon the adoption of IFRS. Please see Appendix 5.5 pages 30 – 32 for more information on MH costs not eligible for capitalization under IFRS.