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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Executive Summary

Among other requests, Manitoba Hydro (MH or the Corporation) applied to the Public Utilities Board (Board) for across-the-board 2.9% rate increases to take effect both on April 1, 2010 and April 1, 2011, and for a further 0.9% rate increase to take effect August 1, 2011. As is always the case with applications made to the Board, the onus is on the applicant, in this case MH, to fully and adequately support requests made. In this case, MH failed to discharge that onus.

In past Board orders arising out of public proceedings concerning MH, the Board has raised concerns with the scale of capital expenditures and new debt MH plans to undertake, plans premised in large part on the expectation of "profitable" net export sales. In those past orders, the Board has suggested there was a risk that if the Corporation's plans were implemented MH may not be able to both meet its domestic and export commitments and achieve its financial targets without having to (with the Board's approval) increase domestic rates not only beyond the levels now projected by MH, but above a level consistent with both public expectations and the general public interest.

Accordingly, within the proceeding just concluded, which not only considered MH's requests but, also, other related matters, the Board undertook an in-depth review of MH's operational business risks and its risk management practices. This review included consideration of the probabilities of occurrence, and possible cost consequences of occurrence, of all identified operational and business risks – this in the context of the Corporation's planned capital spending and concurrent pursuit of export contracts with American utilities.

Unfortunately, in the public hearing that concluded on July 4, 5 and 7 of 2011 (with the closing statements of both interveners and MH), the Corporation either refused or failed to provide the Board information that the Board considers critical to it reaching a comprehensive and final perspective on the prudency of MH's actions and plans, and the implications for domestic rates of MH's operations and plans.

In particular, MH not only failed to provide the Board a fully updated 20-year Integrated Financial Forecast (IFF) – to include recognition of presently very low spot, opportunity and average export prices, and financial scenarios, with stated assumptions, based on capital expenditure plans differing from MH's "preferred development plan", but also refused to comply with a subpoena issued by the Board on July 6, 2011 that seeks the filing of MH's export contracts.

MH intends to seek leave to appeal to the Manitoba Court of Appeal towards its objective of quashing the Board's subpoena. This Board will oppose the granting of leave to appeal and, if granted, plans to oppose MH's effort to quash the Board's subpoena. (The position of the Board with respect to its access to the export contracts is set out in Board Order 95/11, issued July 22, 2011, available on the Board's website: www.pub.gov.mb.ca.)

With respect to alternate capital development scenarios (models providing forecasts of financial results out twenty years) not provided by MH, one scenario among others that the Board wants to be modelled involves the deferral (potentially partial, and potentially to represent a "staggering" of elements of MH's current capital development plan) of the Corporation's current major capital development plan along with the modelling of the expected consequences of the construction of a combined cycle natural gas generation plant in southern Manitoba.

In this Order, and based on the evidence available to it, the Board establishes its concerns with MH's preferred capital expenditure development plan. That plan would have MH construct two new hydro-electric generating stations (a third new plant, Wuskwatim

Generation Station, is nearing completion) and Bipole III, and the Corporation entering into new export contracts towards meeting the costs of advancing the construction of the planned new generation stations well ahead of expected domestic electricity load requirements.

Since MH's plans were conceived "much has changed" – the expected costs of constructing MH's planned new generation and transmission assets has soared by approximately $3.5 billion (to-date); the price MH receives from its American utility counterparties for spot and opportunity export sales – which are anticipated to represent at least 50% of the Corporation's export sales - has fallen dramatically. (MH generally expects "firm" export sales, sales made at prices set in long term contracts, to represent no more than 50% of its total export sales, with the remaining sales being spot or opportunity sales at then-market prices.)

For an extended period of time, and since the fall 2008 when the global credit crisis and recession began to the present time, MH's off-peak spot and opportunity export sales have realized prices as low as 0.5¢/kWh, reducing the average price received for its exports, including its "firm" and peak sales, to below 3.5¢/kWh.

The presently low export prices are generally understood to be attributable to:

a) the employment of new natural gas extraction methods, allowing for the production of natural gas from seemingly abundant shale deposits in North America, and, as well;
b) a reduction in industrial demand, in both Manitoba and in its export market, from previous levels.

The reduction in industrial demand, and reduced projections of future industrial load growth, are due in part to the slow recovery, particularly in the United States, from the recession, and, also, here in Manitoba with the recent closure of a pulp and paper plant and an announcement of an impending closure of an existing Manitoba smelter and refinery operation in Thompson (which follows the closure of another industrial smelter in Flin Flon).

From the evidence currently available to the Board (and in advance of receipt of the export contracts for which the Board has issued a subpoena), the Board is concerned that if MH proceeds with its “preferred development plan” the consequences for Manitoba ratepayers, as to be evidenced in rate increases, may be much higher than MH currently projects.

Ahead of regulatory approvals in both Canada and the United States, MH has already expended hundreds of millions of dollars (and it continues to spend to “protect” the planned in-service dates of its planned new generation and transmission), on its capital development plan, a plan outlined in more depth within the body of this Order.

The Board believes a thorough ‘Needs For and Alternative To’ (NFAAT) process should be held to consider MH’s planned major capital expenditure plans and related new export contracts far in advance of MH making final commitments to enter into its proposed export contracts and undertaking massive new investments.

While MH currently projects that the implementation of its capital expenditure and export contract plans will result in domestic rate increases cumulating over twenty years at approximately 70%, the Board fears that MH has both understated the costs of its preferred development plan and overstated future export sale revenue, with the result potentially being a compound overall increase in domestic rates over the twenty year period twice that forecast by MH.

MH's primary objectives include serving domestic load reliably, and at rate levels consistent with Manitoban expectations. The Board indicates within this Order its concern that if MH proceeds with its development plan "as is" the inadvertent result could be domestic ratepayers subsidizing export sales to the United States. The Board is not at all confident that the risk tolerance exhibited by MH is shared by the majority of its ratepayers.

Thus, despite the lengthiest, most complex and certainly most expensive public proceeding ever held by the Board, a hearing that has involved several interveners and numerous expert witnesses, the Board concludes that, on an interim basis, it must deny not only MH's requests for the finalization of interim rate increases but also approval of a further rate increase at this time.

This is the first of two Board Orders to be issued arising out of the recent public hearing, and, as suggested above, it is focused on MH's rate requests, risks and risk management. The second Order will follow in due course, and will not only address in more depth matters dealt with herein, but also provide the Board's findings on other matters considered in the recent hearing (including ex parte interim rate orders outstanding with respect to MH's Surplus Energy Program, SEP, and MH's Curtailable Rate Program; MH's application for the Temporary Billing Demand Concessions for General Service Medium and Large customers provided in Board Order 126/09 being made permanent; the "firmness" of MH's equity components; the prudency of MH's expenditures; and, the approach to be taken with respect to lower income customers and other rate design matters, including Cost of Service issues).

The second Order will also provide commentary and findings with respect to the participation in the proceeding of interveners and expert witnesses, and address the recommendations made by the interveners and their expert witnesses.

1.0 Application

In November 2009 and pursuant to *The Public Utilities Board Act* and *The Crown Corporation Public Review* and *Accountability Act*, MH applied to the Board for the following:

a) *Approval of rate schedules incorporating an across-the-board 2.9% average increase in General Consumer's rates effective April 1, 2010 (with the exception of Area & Roadway Lighting Class;*

b) *Approval of rate schedules that incorporate a further across-the-board 2.9% average increase in General Consumers' rates effective April 1, 2011;*

c) *Final approval of all Surplus Energy Program ("SEP") ex parte rate orders outstanding;*

d) *Final approval of Curtailable Rate Program ex parte Orders /09 and 63/11; and*

e) *Final approval of Order 126/09, which resulted from MH's application for Temporary Billing Demand Concessions for General Service Medium and Large customers related to the impacts of the economic downturn. MH requests that the Temporary Billing Demand Concessions be made permanent under the program.*

2.0 Background

MH's preceding General Rate Application (GRA) was held in 2008, and was the subject of Board Orders 90/08, 91/08 and 116/08, all of which are available on the Board's website (www.pub.gov.mb.ca).

In Order 90/08, as in prior Orders going back to 2004, the Board raised many concerns about the risks faced by MH. In particular, and more recently, the Board has raised concerns with the scale of capital expenditures and new debt MH plans to incur over the next 15 years. The Board also suggested that there is a risk that the Corporation may not be able to meet its domestic and export commitments without having to resort to high-priced imported power and/or Manitoba thermal generation (also at a high cost), and both with environmental implications during years of lower than median water conditions.

The Board, in Order 90/08, granted a 5% rate increase effective August 1, 2008. In granting the increase, the Board stated:

> *"Despite the Board's limited mandate with respect to capital costs, the Board expresses concern, not to be confused with opposition, with the unprecedented capital expenditure levels, and questions whether the export revenue stream from new generation and transmission projects will be sufficient to cover the financial obligations related to these works, given the inherent risks that are present and lie ahead.*
>
> *The Board will seek further assurances from MH that new contracts are priced at or above forecast average export prices."*

The Board also directed MH to file information in support of a 4% conditional rate increase, which was to be effective April 1, 2009. MH filed additional information that included updated financial forecast information (IFF 08-1). Upon a review of the information, the Board, in Order 32/09, revised the 4% conditional rate increase to 2.9%, and noted recent improvements in MH's published financial position to be balanced with the Board's ongoing concerns related to the Corporation's multiple and major risks.

In that Order, Board Directive 4 required:

> *"MH to file by September 30, 2009 for Board approval, a conceptual line for an in-depth and independent study of all of the operational business risks facing the Corporation. The study to be a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending taking into account export revenue growth, variable interest rates, drought, inflation experience and risk, and potential currency fluctuation."*

On December 1, 2009, MH filed a General Rate Application (GRA) seeking across-the-board 2.9% average rate increase in General Consumer rates effective both April 1, 2010 and, also, April 1, 2011.

In accordance with previous directives issued by the Board, MH filed (in confidence with the Board) documents related to its risk management assessment and practices. Through a review of the information, the Board determined that a special hearing process was required to consider how best to address the confidential information that would allow for an appropriate review of MH's risk management.

Accordingly, on December 10, 2009 and December 22, 2009 the Board held Pre-Hearing Conferences, the first considered whether and how to incorporate a review of MH's risks and risk management into the GRA process; the latter dealt with which Interveners should be approved for participation in the GRA public process and the establishment of a timetable for the orderly exchange of evidence (to lead up to public hearings, then-planned to commence in 2010).

Among the issues canvassed was whether the Board should retain an independent risk consultant. Subsequently, the Board issued Order 17/10 (dated February 9, 2010) which concluded that a detailed risk and risk management review would be addressed in the GRA.

Order 17/10 also approved the following parties as Interveners to the GRA:

i) Consumers' Association of Canada (Manitoba) Inc., Manitoba Society of Seniors (CAC/MSOS);

ii) Manitoba Keewatinook Ininew Okimowin, (MKO)

iii) Manitoba Industrial Power Users Group (MIPUG);

iv) City of Winnipeg (City); and

v) Resource Conservation Manitoba (now Green Action Centre) and Time to Respect Earth's Ecosystems (RCM/TREE).

The Board then issued Order 30/10 (dated March 26, 2010), and, in Schedule C of that Order, the Board provided the terms of reference for the engagement of independent experts by the Board to undertake an independent risk and risk management review. Additionally, Southern Chiefs Organization (SCO) was added as an Intervener.

Matters related to the risk review and other procedural matters led to a lengthy delay in the commencement of the GRA, which was held over 41 hearing days (commencing January 5, 2011 through and including June 9, 2011). Closing submissions by Interveners were heard by the Board on July 4 and 5th of 2011, followed by MH's closing submission provided on July 7, 2011.

Due to the delay in the commencement of the hearing, the Board heard submissions from MH and Interveners on January 19, 2010 to consider whether an interim rate increase should be granted effective April 1, 2010. The Board (in Orders 18/10 and 33/10) provided an interim approval of a 2.9% across-the-board rate increase (except for the Area and Roadway Lighting Class, for which no rate increase was approved). Subsequently in 2011, the Board received submissions from Interveners and MH as to whether an additional interim 2.9% rate increase (as applied for by MH) should be granted effective April 1, 2011. Following receipt and consideration of submissions, the Board issued Order 40/11, which approved an interim 2% across-the-board rate increase for all classes (again except for the Area and Roadway Lighting Class, for which no rate increase was approved).

In MH's closing submission of July 7, 2011, MH requested the two interim rate Orders be finalized and an additional 0.9% rate increase be granted (the latter to take effect August 1, 2011).

To respond to MH's request for the finalization of the two interim rate Orders and approve an additional 0.9% rate increase to be effective August 1, 2011, the Board issues this interim Order, it being the first of two planned Orders to address all issues raised in MH's GRA. Findings and information in this first Order are to be expanded upon in the second Order, which is to follow in due course. The positions of MH, Interveners and experts on various issues will be detailed in the second Order, which may also include additional Board findings and directives.

3.0 Key Information

3.1 Operating Results

In support of its Application, MH filed an Integrated Financial Forecast (IFF), MH IFF 09-1 for its electric operations, as well as a Capital Expenditure Forecast (CEF) CEF 09-1, both forecasts extended from MH's fiscal year 2009/10 to fiscal year 2019/20. Updated forecasts (IFF MH 10-1 and CEF 10-1) were filed later in the hearing. IFFs and CEFs are prepared to provide an indication of the long-term financial direction, plans and expectations of the Corporation, and are based on numerous assumptions.

MH's actual results for fiscal year 2009/10 and its forecasts for fiscal years 2010/11 and 2011/12 (the annual report of MH, to include its audited financial statements for 2010/11 has yet to be released) projected accumulated net income for fiscal years 2009/10 to and including 2011/12 will be $148 million higher (pursuant to IFF 10-1) than was indicated in IFF 09-1 (IFF 09-1, the IFF which was filed in the Application).

The projected improvement in accumulated net income and period ending retained earnings (retained earnings represent MH's "equity" or capital) was primarily attributed to lower than forecast depreciation, finance expense and fuel & power purchase costs. As well, the forecast represented a continuation of MH's accounting practice of capitalizing and deferring expenses incurred in current and past periods associated with the Corporation's plans to construct additional generation and transmission assets.

MH's IFF 09-1 indicates MH achieved its 75:25 debt to equity ratio financial target. While the 75:25 debt to equity ratio target has generally been accepted as being representative of an adequate capital structure, this Board has questioned the "firmness" of components of the equity factor (which include contributions in aid of construction, Accumulated Other Comprehensive Income, and intangible and deferred costs – all "illiquid"), and has raised doubts as to whether the present target ratio of 75:25 will remain adequate if MH's proceeds to expend (largely based on additional borrowings) approximately $20 billion on new major generation and transmission assets over the next ten or so years).

MH's IFF 10-1, a partially updated forecast still largely based on assumptions that underlie IFF 09-01, supports in part the Board's interim rate approvals of 2.9% and 2% effective April 1, 2010 and April 1, 2011, respectively.

MH's actual and currently forecast operating results compared to forecasts of the preceding 2008 GRA are as follows:

Table 1

Pro Forma Statement of Operations & Retained Earnings

($ Millions)		**Actual**			**IFFIO-1**	
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**	**Total 2008-2012**
Revenue						
Domestic	1,006	1,014	980	1,006	1,048	
Estimated PUB Approved Increases	77	130	162	195	224	788
Export	625	623	427	444	461	
Total Revenue	1,708	1,766	1,569	1,645	1,733	
Expenses	1,371	1,478	1,409	1,496	1,612	
Non Controlling Interest					4	
Net income(loss) Actual/[IFF 10 -1]	337	288	160	149	125	
Compared to 2008 GRA Forecast						
Net income(loss) [IFF 10 -1]	264	156	105	116	114	
Net income difference	73	132	55	33	11	304
Retained earnings Actual/IFF 10 -1	1,790	2,078	2,238	2,354	2,479	
Retained earnings IFF07-1	1,735	1,891	1,996	2,112	2,226	
Cumulative Retained Earnings difference						
2008 GRA vs 2011 GRA	55	187	242	242	253	

Note: Board approved increases granted in prior Applications: 5% effective August 1, 2004 (a $48 million addition to annual revenue); 2.25% effective April 1, 2005 ($21.8 million of additional annual revenue); and, 2.25% effective February 1, 2007 (an additional $23.0 million of annual revenue). The interim increases provided as of April 1, 2010 and 2011 represent a further addition to annual revenue of, in aggregate, approximately $48 million.

Overall, and on the "face of it" (setting aside the Board's ongoing concern with respect to MH's practice of deferring and/or capitalizing a significant amount of its annual OM&A expenditures), MH's financial position since the 2008 GRA is projected by MH to improve by approximately $253 million over the period 2007/08 through to and including 2011/12.

It is important to note that since 2008, this Board has approved rate increases that are expected to provide MH over $788 million in accumulated additional revenue through to and including fiscal 2011/12.

In the decade prior to 2004/05, in essence domestic rates remained "frozen" and MH relied on net export revenues to meet its increased reported annual expenditures and pursue its financial targets (debt to equity ratio, interest coverage and capital expenditure coverage).

3.2 Financial Targets

MH's most recent financial targets (as established by MH's Board of Directors and generally accepted by this Board – with reservations given the components of equity and the plans for massive borrowing - and Interveners to MH GRA proceedings, to-date) are as follows:

1. Achieve and maintain a minimum debt to equity ratio target of 75:25 by no later than 2011/12;
2. Achieve and maintain an annual gross interest coverage ratio of 1.20 annually; and

3. Fund all new capital construction requirements (except major new generation and/or major new transmission facilities, plus the new head office), from internal sources (net income and non-cash expenditures).

Debt to Equity

The debt to equity ratio has been the focus of attention at this and prior hearings and this ratio has been employed as one means of assessing the capital adequacy of MH – i.e. its "financial strength", by comparing MH's debt to its equity.

While MH's debt is secured for its lenders by the guarantee of the Province (which annually charges MH a 1% debt guarantee fee), lenders and credit rating agencies relied on by lenders, given the significant percentage of overall Provincial Government debt that is comprised of MH borrowings, pay attention to the reported capital adequacy of MH when considering the interest rates the Province itself will have to bear when it issues debt.

At the 2008 GRA, MH's filed IFF 07-1 did not project MH reaching its debt to equity target of 75:25 during the then-forecast ten year period through fiscal 2017/18. However actual events and the latest forecast suggest a changing "landscape".

MH's actual and forecast debt to equity ratios for its fiscal years 2007/08 to and including 2017/18, from IFF 10, as compared to IFF 07-1 as it was filed at the preceding GRA, are as follows:

Table 2

Debt to Equity Ratio Comparison

	Actual			Forecast		
Fiscal Year	2008	2009	2010	2011	2012	2018
Actual/IFF10	73:27	77:23	73:27	74:26	74:26	82:18
IFF07-1	77:23	77:23	77:23	78:22	78:22	78:22

Based on MH's IFF 10-2, again a partially updated version of IFF 09-1, MH will continue to meet the 75:25 debt to equity ratio target as of March 31, 2011, continue to meet the target through to the end of fiscal 2011/12, then, as a result of planned capital expenditures, fall below the equity target.

Since the 2003/04 drought, where a loss of $436 million was reported driving up the debt component of the debt to equity ratio, MH's capital structure (as reported by MH) has improved.

MH's "reportedly" improved financial position relates to three major factors:

a) higher than expected extra provincial revenue (net export revenue) in fiscal 2006 – this driven in large part by a spike in natural gas prices following hurricanes Katrina and Rita that "drove up" opportunity export sales prices at a time of high water flow conditions;
b) rate increases granted by this Board in 2004 (5%), 2005 (2.25%), 2007 (2.25%), 2009 (5%), and interim increases granted as part of the current proceeding in 2010 (2.9%) and 2011 (2.0%); and,
c) a decrease in borrowing rates, particularly short-term rates, this largely the result of government actions following the global credit crisis and recession (the former commencing in the fall of 2008 and both concluding in 2009/10).

On an overall basis, domestic electricity rates have increased, on a compounded basis, by over 22% since 2004 – an increase that exceeds the general rate of inflation through the period.

MH having attained the debt:equity target (again, this Board has reservations with respect to how MH's calculates the equity component of the ratio), and despite the Corporation's forecasts of annual rate increases of 3.5% for the years 2013 through 2021, a rate of increase much higher than the expected rate of inflation, MH does not anticipate maintaining its target debt:equity ratio. MH projects that its debt to equity ratio will "slip" (deteriorate) due to MH's planned major capital program.

MH currently forecasts, (forecasts having only been partly updated) that its debt to equity ratio will decline to 82:18 as of March 31, 2018, a ratio worse than that MH contemplated in its IFF 07-1 (filed in the 2008 GRA). MH's capital structure is forecast to weaken even further after 2018, before the Corporation's anticipated in-service dates of both Keeyask and Conawapa generation stations, with the debt to equity ratio now projected by the Corporation to reach 84:16 as of March 31, 2021.

In support of its most recent Application, and as previously indicated, MH filed IFF MH 09-1 and CEF 09-1. MH then-anticipated capital spending of $13.1 billion on three major Generation and Transmission projects (Keeyask Generating Station, Conawapa Generating Station and the Bipole III Transmission line). MH concurrently forecast that its long term debt would increase from $7.8 billion (as of March 31, 2010) to $17.7 billion as of March 31, 2029, a projected increase of $9.9 billion.

However, MH has since revised its capital cost projections for the three major projects. As reflected in MH's IFF 10-2, MH now projects the capital cost of the three major projects to be in the range of $16.6 billion – approximately $3.5 billion higher than MH forecast in CEF 09-1, only one year earlier. Concurrently, MH also increased its forecast of required additional debt, now projected by the Corporation to increase by over $15 billion, and to reach $23 billion as of March 31, 2029, an increase in projected long term debt in excess of $5 billion from the Corporation's previous forecast.

As a result of the increased capital expenditure forecast, MH has now projected that its debt to equity ratio as of March 31, 2029 will change from the 51:49 projected in its IFF 09 forecast (that forecast represented an expectation that significant annual net income results would result in what the Corporation denoted as its "decade of return", which was projected to follow MH's "decade of investment") to 72:28 (that ratio drawn from MH's partially updated IFF 10). It is important to note that MH's revised debt to equity ratio projection of 72:28 still does not take into account the current low prices being received for spot, opportunity and average export sales.

The change in MH's forecast of its debt to equity ratio as of March 31, 2029, a date at which MH currently plans to be operating Keeyask, Conawapa (relying on Bipole III), and exporting significantly increased volumes of power to the United States, represents a material negative financial change – one that appears to acknowledge the new and higher capital cost forecast and the impact of higher capital expenditures on forecast annual amortization and finance expense.

Changes to Generally Accepted Accounting Practices (GAAP), with the move to International Financial Reporting Standards (IFRS) expected to occur in MH's fiscal year 2012/13, raise the potential for an expensing (write-off to retained earnings) of Rate Regulated Assets of over $300 million (OM&A expenditures that were deferred, not included as a period expense in the year of incurring, and now classified as an "asset" in MH's balance sheet). If this occurs, MH's debt to equity ratio will be negatively affected.

3.3 Operating, Maintenance and Administrative Expenses (OM&A)

3.3.1 Capitalization of Operating and Administrative Expenditures

While MH's rates are largely driven by its capital assets (generation, transmission and distribution), they also reflect the Corporation's Operating, Maintenance and Administrative (OM&A) expenditures. In setting rates, the Board's goal is that those rates are not only just and reasonable, but also reflect prudent expenditures (the concept of prudency extends not only to capital expenditures, but also to OM&A costs).

A particular difficulty in setting what is to be "just and reasonable rates" reflective of prudent actions by the Corporation is that the Board does not have jurisdiction with respect to MH's capital expenditures. Since the Corporation is wholly owned by the Province, i.e. it is a Crown Corporation, the practice of disallowing expenditures, whether capital or OM&A, considered not to be prudent is more problematic than in the case of privately owned utilities, where disallowance affects private not public interests. To disallow an expense of a Crown Corporation would, in effect, send a "message", but as to who is to "pay the cost", it would simply "move" the disallowed cost from the utility's ratepayers to the taxpayers of the Province.

As previously indicated, MH defers and/or capitalizes certain of its operating, maintenance and administrative expenditures. A significant percentage of MH's annual OM&A expenditures incurred in its fiscal years have been or are to be capitalized or deferred (and then categorized as "assets" and not expensed), to be amortized over a period of years (with the amortization period for certain of those capitalized expenses to begin only after the "in service" date of a new Generating Station or transmission line).

The outcome of “capitalization” is, in essence, the transfer of a cost incurred in one particular fiscal year to other years, as the initial cost could be amortized over the expected service life of the “asset” it is associated with. With capitalization of OM&A, the rates of current ratepayers are restrained, with responsibility, in the form of impact on rates, transferred to future generations of ratepayers.

Private corporations, which pay income taxes, tend to “write-off” period expenses rather than capitalize or defer them, the effect of doing so reduces the income tax liabilities of the corporations while relieving future annual statements and, potentially, customers, of costs that would, if capitalized, fallen in future years.

MH segregates its costs between operating activities, which are a direct charge against the operating income for the year the expenditure occurs, and “capital” activities, which are deferred or capitalized in the year of incurrence and charged to future periods and amortized over the future life of the respective capital project. In addition, MH also capitalizes a significant component of its annual administrative overhead by applying predetermined overhead rates to all capital projects.

Over 75% of operating and administration costs (OM&A) relate to labour costs, including employee benefits. Manitoba Hydro had total (OM&A costs before capitalization or deferral of $543 million in 2003/04, an annual amount that increased to over $688 million in 2010, and was recently forecast to increase further to $704 million in fiscal 2010/11 and $714 million in 2011/2, before capitalization and/or deferral.

In 2003/04, MH capitalized or deferred a significant portion of its period costs, including approximately 28% of labour and benefits costs.

Actual and forecast operating and administrative expenses, before and after capitalization, for the fiscal years 2007/08 to and including 2011/12 are as follows:

Table 3

Operating and Administrative Costs ($000's)

	Actual			IFF10-01	
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**
Labour					
Wages, Salaries	$359.3	$380.0	$408.0	$415.2	$424.8
Overtime	$41.8	$45.9	$50.3	$48.1	$49.2
Employee Benefits	$76.8	$83.7	$82.7	$93.0	$95.2
Labour and Benefits	$477.8	$509.9	$541.0	$556.3	$569.1
Employee Safety & Training	$3.7	$4.2	$4.6	$4.8	$4.9
Travel	$28.3	$31.8	$32.4	$33.0	$33.7
Motor Vehicle	$22.4	$24.1	$24.3	$23.1	$23.7
Materials & Tools	$27.8	$29.4	$26.9	$26.2	$26.8
Consulting & Professional Fees	$7.5	$9.7	$14.8	$10.9	$11.2
Construction & Maintenance Services	$15.9	$18.4	$20.1	$21.8	$22.3
Building & Property Services	$25.7	$29.0	$22.9	$20.7	$21.2
Equipment Maintenance & Rentals	$11.7	$13.0	$14.4	$13.9	$14.2
Consumer Services	$4.7	$5.3	$5.8	$5.7	$5.8
Computer Services	$1.1	$0.9	$1.0	$0.7	$0.7
Collection Costs	$5.3	$5.0	$4.6	$4.5	$4.7
Customer & Public Relations	$6.7	$6.9	$8.2	$6.0	$6.2
Sponsored Memberships	$1.2	$1.5	$1.3	$1.3	$1.3
Office & Administration	$14.4	$14.7	$15.3	$15.7	$15.9
Communication Systems	$1.4	$1.5	$1.8	$1.6	$1.6
Research & Development Costs	$3.0	$3.1	$4.0	$4.1	$4.2

	Actual			IFF10-01	
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**
Contingency Planning				$5.4	$3.9
Operating Expense Recovery	($23.3)	($21.5)	($21.6)	($16.5)	($16.7)
Total Costs	**$638.6**	**$687.2**	**$723.0**	**$740.2**	**$755.6**
Operating and Administration Charged to Centra	($56.3)	($59.0)	($61.0)	($63.4)	($64.0)
CICA Accounting Changes*		$5.0	$9.0	$9.0	$9.0
Provision for Accounting Changes				$18.0	$13.5
	$582.3	**$633.1**	**$688.0**	**$703.8**	**$714.1**
Capital Order Activities	($192.3)	($203.1)	($224.3)	($235.0)	($239.7)
Capitalized Overhead	($67.3)	($65.7)	($69.2)	($71.0)	($72.5)
O&A Attributable to Electric Operations	**$322.7**	**$364.3**	**$377.6**	**$397.7**	**$401.9**

The amount of annual labour and benefits being capitalized has increased to the point where MH now capitalizes over 32% of its annual labour and benefit costs. The increase in amounts capitalized mutes, or masks, the growth in OM&A expense recorded on an annual basis.

If MH were to expense, i.e. charge against annual revenue/net income, labour and benefit costs that it now capitalizes, MH would, in the absence of larger rate increases than those now projected for future years, report net losses in many of its forecast future operating years, rather than forecasting annual net income for every one of its projected future years as it currently does.

Including overheads, in total MH forecast the capitalization of $306 million ($235 million with respect to in capital asset construction activities and $71 million of administrative overhead) of OM&A expenses in fiscal 2010/11, and over $312 million ($240 million in capital order activities and $72 million in overhead) in fiscal 2011/12, representing over 43% of its annual electric operating expenses in those two years.

A further analysis and discussion of the cost deferral and capitalization practices of MH will be provided in the subsequent second Order of the Board to arise out of the recent hearing.

3.3.2 Growth in OM&A

Operating and Administration Expenses, as recorded in MH's audited financial statements – after capitalization, have increased from $323 million in fiscal 2007/08 to $364 million in fiscal 2008/09; the two "test years" from the 2008 GRA (and representing an increase in one year of 13%). OM&A expenses, as recorded as an expense in MH's accounts, further increased to $378 million in 2010, an additional $13 million or 3.6% change from the prior year.

From fiscal 2004/05 through fiscal 2009/10, MH's OM&A expenses have grown at a compound average growth rate of almost 5% annually, while inflation for that period has been under 2% per year. MH forecast OM&A expense to be $380 million in fiscal 2010/11 and $403 million in fiscal 2011/12. And, MH provided an update at the hearing with its IFF 10-1, wherein the OM&A expense projection was revised, to $398 million for fiscal 2010/11 and $402 million for fiscal 2011/12 (as reflected in the above table).

MH attributed the increases in part to accounting changes (to conform with changes to GAAP, as GAAP transitions to comply with International Financial Reporting Standards, IFRS). Canada is in the process of converging its accounting practices with international accounting standards, which will, when the transition is complete, become the new Canadian GAAP.

OM&A increased in 2009/10 by $11 million, and MH recently forecast further increases in the order of $31 million for fiscal 2010/11 and $27 million for fiscal 2011/12 (incorporating provisions for expected IFRS mandated accounting changes to impact OM&A by $18 million and $14 million, for the respective years).

OM&A are direct expenses within the control of MH (some of these direct expenses have a “fixed” aspect – required annual expenses such as insurance premiums and building operation costs, while others are more of a variable nature, such as external legal and consulting fees, more susceptible to reduction).

MH indicated in the recent proceeding that it plans to “control” and restrain OM&A spending by implementing a number of measures, including a “general” hiring freeze (which provides for exceptions), restricting travel to only “out of Province” trips deemed very essential, and extending the service life of computer equipment (which lowers annual amortization expense, while extending the number of years amortization expenses occur related to those assets).

These actions, together with other measures related to targeted initiatives, were forecast by MH to save between $11 million to $13 million in expenses in the current year, fiscal 2010/11. MH also considered freezing management and executive salaries, an action that would have been consistent with the freezing of civil service salaries undertaken by the Province, but did not do so, asserting that to do so could risk the loss of key personnel to other utilities in other provinces. (MH testified that it had lost five employees to Saskatchewan Power over the last year, this out of a total complement of approximately 6,700).

A further discussion and analysis of MH's OM&A expenditures and the Board's perspective on the prudency of MH's OM&A expenses and its recent cost constraint measures will be provided in the subsequent Order of the Board.

3.3.3 Staffing Levels

A major driver of increases in OM&A expense (both before and after capitalization of OM&A) is increased staffing levels, which, despite MH's assertion that it seeks to restrain hiring, have been projected to increase from 5,769 Equivalent Full Time (EFTs) in 2004 to 6,669 EFTs, an increase of 900 EFT's (over 15%).

The increase in staffing levels and related labour costs was attributed by MH to be largely due to increased work requirements, with the largest additions to staffing levels taking place in three of its operating divisions: Power Supply (an increase of 498 EFT), Transmission & Distribution (an increase of 151 EFT), and Customer Service & Distribution (an increase of 146 EFT).

MH indicated that a large percentage of those recently hired were engaged to work on current and planned capital projects.

3.3.4 International Financial Reporting Standards (IFRS) Transition

Canadian accounting standards for financial accounting and reporting by publicly accountable private businesses and government business entities (the latter includes MH) are established by the Accounting Standards Board (of Canada, AcSB). AcSB's decisions represent Generally Accepted Accounting Principles (GAAP) in Canada. The International Accounting Standards Board (IASB) – which assumed the responsibilities, in 2001, of the previous International Accounting Standards Committee - establishes accounting standards meant for universal global adoption.

Standards adopted by IASB are denoted as International Financial Reporting Standards (IFRS), and AcSB has adopted IFRS as the new GAAP for Canadian enterprises, and is transitioning to that end.

The opinions of auditors of publicly accountable enterprises on the financial statements of those enterprises are based on compliance with GAAP, and those opinions, and the associated financial statements, are carefully considered not only by the general readership of such statements, but also investors in, lenders to (also the credit rating agencies relied upon by lenders) and regulators of those enterprises.

While the general accounting principles of what was Canadian GAAP are similar to those of IFRS, there are differences, and those differences, as IFRS has prevailed, have already affected and, particularly in the case of rate regulated utilities, will continue to affect financial reporting in Canada. IFRS provides a principle-based approach that values substance over form, relies more on fair (market) value, and seeks to achieve enhanced transparency. “Fair value” accounting, as compared to previous GAAP, has and will require adjustments to enterprise balance sheets and income statements.

IFRS was adopted as Canadian GAAP effective January 1, 2011. However, Canadian utilities were granted an optional one year deferment of implementing of IFRS, this to allow for an orderly transition from current Canadian GAAP accounting standards that recognize “rate regulated” assets and liabilities to those that do not.

Rate regulated assets represent expenditures currently allowed under Canadian GAAP to be capitalized or deferred, and not recorded as period expenses (for later amortization, over periods of time extending as much as 60 years), but which will be required to be recorded as period expenses under IFRS for fiscal years commencing on or after January 1, 2012.

MH has advised that it will be required to prepare IFRS compliant financial statements for its fiscal 2012/13 year, with comparative financial information for 2011/12.

MH has advised that its pending implementation of IFRS has prompted it to delay undertaking certain long outstanding Board-requested studies, including: a) an Independent Benchmarking Study of Key Performance Metrics, to compare MH's operational costs against those of other utilities; and, b) an Asset Condition Assessment Report, to assess the present condition of MH's assets and provide for possible future action such as asset upgrades and/or replacements.

These studies, which remain outstanding, were ordered to be developed and filed with the Board by way of Directives 4 and 7, respectively, of Order 150/08.

Pursuant to IFRS, and as previously indicated, MH reported that it may be required to write-off "rate regulated" assets, and that doing so would be expected to reduce its retained earnings by over $300 million (which would negatively affect MH's present and future debt to equity ratio).

MH has indicated that it will propose to the Board an approach that would allow for the continuation of "rate regulated" assets for rate setting purposes, although no details of such an approach has been provided. The Board would have to accept amendments to MH's audited accounts for rate setting purposes (i.e. "two sets of books"), if it were to agree to the approach being considered by MH.

A further discussion of IFRS and related accounting matters will be provided in the subsequent Order of the Board.

3.4 Power Resource Planning

The Wuskwatim Clean Environment Commission (CEC) hearing of 2003 (two members of the Public Utilities Board sat on that panel with members of the Commission) reviewed MH’s then-plans to construct Wuskwatim Generating Station and related Transmission (at a cost then projected to be of approximately $900 million. CEC is an advisory body, not a quasi judicial administrative tribunal such as the Public Utilities Board.

While the CEC’s review considered MH’s Wuskwatim proposal, then based on an expected cost of $900 million, as being advanced for export sales and not domestic purposes, the latest estimate is $1.6 billion, approximately 75% higher, while MH first adjusted its view of the project, suggesting that it was required for domestic load requirements; it has reverted to its initial expectation that Wuskwatim will be employed for export sales.

Projects advanced for export purposes are expected to produce annual profits representing an acceptable rate of return on investment, whereas projects required for domestic load do not. With Wuskwatim now expected to be in-service in fiscal 2011/12, its generation understood to be sold, at least until new export sales contracts “kick-in”, at spot or opportunity export sales prices, which, currently, are only one-third of Wuskwatim’s expected per unit in-service costs.

The experience of Wuskwatim suggests that MH's planning for future investments in generation and transmission require significant testing ahead of approval, yet MH has put forward a very limited range of development scenarios with respect to meeting future domestic load growth.

Since 2004/05, MH's Power Resource plans have contemplated new major generation to meet projected future increases in domestic load requirements. The following table provides a snapshot of the progression of MH's expectations with respect to "dependable" hydraulic generation output:

Table 4

Dependable Hydraulic Growth

POWER RESOURCE PLAN YEAR	POST-WUSKWATIM DEPENDABLE HYDRO GWh	RECOMMENDED POWER RESOURCE PLAN GENERATION GWh/Additions	ALTERNATIVE POWER RESOURCE PLAN ADDITIONAL GWh/Additions
2004/05	22,500	26,900 – Conawapa (2024/25)	25,400 – Keeyask (2024/25)
2008/09	22,500	25,400 – Keeyask (2018/19) 29,800 – Conawapa (2022/23)	28,900 – 400 MW CCCT (2018/19) 30,400 – Conawapa (2020/21)
2009/10	22,500	25,400 – Keeyask (2018/19) 29,800 – Conawapa (2022/23)	26,900 – Conawapa (2021/22) 30,400 – 40 MW CCCT (2023/24)
2011 Outlook	22,500	25,400 – Keeyask (2020/21) 29,800 – Conawapa (2023/24)	Not Identified

For MH's recommended major development plan (the construction of Wuskwatim, nearing completion, plus Keeyask and Conawapa Generation Stations and Bipole III), the Corporation's dependable hydraulic power resources can be compared to domestic load requirements (and hydraulic shortfalls) as follows:

Table 5

Power Resources, Domestic Load and Dependable Hydraulic Shortfalls

Forecast Year	Projected 2020/21 Domestic Load (GWh)	Shortfalls (GWh)	2025/26 Projected Domestic Load (GWh)	Hydraulic Shortfalls[1] (GWh)
2004/05 Forecast	26,600	4,100	27,900	1,000
2008/09 Forecast	29,700	4,600	31,200	1,400
2009/10 Forecast	28,800	3,400	30,600	800
2011 Outlook	27,000	4,500 Pre-Keeyask 1,600 Post-Keeyask	28,900	900

It should be noted that each of these forecasts rely on about 4,000 GWh/year of non-hydraulic dependable resources in MH's fiscal year 2020/21. However, in MH's Outlook IFF 10-2 that level of shortfall of dependable hydraulic energy requirement is, pre-Keeyask, the same as it was in MH's 2004/05 forecast.

MH's preferred Power Resource Plan remains essentially unchanged since 2008/09, a time when domestic load forecasts were about 2,500 GWh/year higher than MH's most recent forecasts. In the absence of the recently announced additional export sales to Minnesota Power, Wisconsin Public Service and Northern States Power, it would appear MH could defer Keeyask G.S. (G.S., generation station) by about six years, rather than the one year deferral modelled in MH's IFF 10-2.

During the proceeding, MH modelled only two alternatives: a) build (MH's preferred approach - the construction of Wuskwatim, Keeyask, Conawapa and Bipole III, a plan that requires new export contract commitments); and, b) "no build", i.e. the development of Wuskwatim, Conawapa and Bipole III, to service domestic load when required and sell excess generation through opportunity export sales).

MH's witness, ICF, provided an estimated present value of MH's preferred approach which indicated that the approach, compared to the "no build" scenario (which omits Keeyask), the only other scenario seriously modelled by MH, could be expected to be moderately beneficial for domestic customers.

However, that estimate was made prior to ICF's awareness of the recent increases to MH's capital cost projections and the steep "fall off" of average export prices. As well, there has been a substantial "run-up" of the Canadian dollar (export sales to American counterparties are prices in USD), and a change in the outlook for carbon pricing has occurred. MH has reported that in its new export contracts with American counterparties, all "environmental" attributes or benefits associated with "clean" power is to go to the counterparties, and not to MH.

When ICF was cross-examined at the hearing, the witness acknowledged that the now expected $3.5 billion increase in the capital cost of MH's development scenario invalidated the consultant's earlier estimate.

MH also advised that it had, earlier, considered an alternative approach beyond that of the "no build" option, one relying on the construction and use of Combined Cycle Combustion Turbine (CCCT) thermal generation (refer to MH's 2008/09 and 2009/10 Alternative Development Sequences), MH did not, in the end, consider employing CCCT generation as a means to defer new hydro generation, and possibly transmission, as is now proposed for in its capital development plan.

The deferral of new hydro-electric generation in favour of the diversification of supply through the construction of CCCT generation would represent an approach that may not require additional firm export contracts.

MH asserted that Keeyask G.S. cannot proceed without Bipole III being in place. While the primary rationale for Bipole III has been to enhance reliability, MH asserts Bipole III is also required if Keeyask or Keeyask and Conawapa are to be built.

While there is no doubt Bipole III is required to transmit Conawapa generation, based on the capacity of the current system, existing Bipole I and II transmission appear capable of handling perhaps 80% of the maximum capacity of Keeyask/Kettle/Long Spruce/Limestone Generating Stations. This approach would have been adequate to transmit the entire output of those generating stations in 29 of the last 30 years, and without Bipole III.

Further discussion and analysis of these matters not only follow later in this Order but will also occur in the subsequent Order, and, presumably, would be one of the matters to be considered in a NFAAT proceeding.

3.5 Capital Expenditures

MH's capital estimates for major generation and transmission projects have been subject to significant periodic and dramatic upward cost adjustments.

In total, the estimated cost of MH's planned major generation and transmission expenditures has risen from $16 billion (from MH's CEF-08) to $20.5 billion (March 2011's CEF), and, more recently, to at least $23 billion (this estimate includes $1.9 billion now apparently required to upgrade Point du Bois, circa 2031).

As the volume of additional power that would be generated from Wuskwatim, Keeyask and Conawapa exceeds expected domestic requirements for decades, MH's "business plan", or strategy, seeks to sell the generated power that is expected to be in excess of domestic requirements to export customers, those primarily being American utilities. In fact, MH expects to obtain approximately 40% of its foreseeable future total electricity revenues from the export market.

In short, export sales would not be a “by product” of MH generation directed to fulfill domestic needs, but a significant market component in itself, one undertaken with the “hope” that domestic ratepayers would not be negatively impacted. To accomplish such a high level of overall revenue coming from export sales, MH plans to advance, well ahead of projected Manitoba demand, new major generation and transmission projects.

MH’s recommended and preferred development plan was first outlined in its 2008/09 Power Resource Plan, and, as well, in MH’s CEF-08. The focus of the plan is the construction of three major projects – Keeyask, Conawapa and Bipole III. The purpose for Wuskwatim, originally conceived as a generation source for export sales, was revised by MH in this proceeding as being required for domestic purposes, although domestic load is not expected to require additional generation until 2019.

Generation and transmission to meet domestic requirements are not subject to an economic evaluation, whereas plants constructed for export purposes do. The increase in the capital cost of Wuskwatim (which was first forecast at $900 million and is now forecast at $1.6 billion), in conjunction with the currently low average export sales prices and reduced domestic load growth, is unlikely to allow for a positive “economic” evaluation at this time.

The Board acknowledges that events post-2008, which have “dimmed” future immediate year net income prospects for the generation to flow from Wuskwatim, could not have been anticipated at the time of the CEC hearing.

Since MH's 2008/09 Power Resource Plan, the estimated construction costs for the three major projects have been adjusted upward, as follows:

Table 6

Major Generation and Transmission Projects Capital Cost ($billions)

	CEF-08	CEF-09	MAR/2011 CEF	LATEST
Bipole III	$ 2.25	$ 2.25	$ 2.25	$ 3.20 to $4.1 [1]
Keeyask G.S.	$ 3.70	$ 4.59	$ 5.64	$ 5.64
Conawapa G.S.	$ 4.98	$ 6.33	$ 7.77	$ 7.77
TOTAL	$10.93	$13.17	$15.66	$16.61 to $17.5

[1] The higher estimate has not been endorsed by MH.

3.5.1 Keeyask & Conawapa

Keeyask G.S.

In MH's 2004/05 Power Resource Plan, MH's cost estimate for Keeyask G.S. was $1.7 billion. This has subsequently been increased as follows:

CEF-08	$3.70 B	
CEF-09	$4.59 B	(25% increase)
CEF-10	$5.64 B	(18% increase, accumulated increase 52.4%))

MH cited material supply and labour shortages (which MH claimed resulted in "sticker shock") as the primary cause of cost forecast escalation when it submitted CEF-09; no specific cause was identified for the most recent increase.

Conawapa G.S.

When (circa 1990) MH looked to building Conawapa G.S. (then in order to service an expected Ontario export sale), the estimated construction cost was $3.8 billion for the Generating Station - this similar to the estimated cost of $4.0 billion reflected in CEF-04 for the project.

MH's CEF-05 and CEF-06 reported escalations in the projected cost of Conawapa, first to $4.5 billion and then to $5.0 billion. MH did not further increase its cost estimate for Conawapa in either its CEF-07 or CEF-08 reports. However, MH's CEF-09 indicated a further 25% increase in the estimated cost for Conawapa, to $6.3 billion, and, with MH's CEF-10, the cost estimate was increased by a further 25% to $7.8 billion (73% over the CEF-05 and CEF-06 estimates).

MH has not provided any specific details to support these large increases.

3.5.2 Bipole III

Bipole III, then with an "east side" of the Province alignment, was proposed initially in 1990 to accommodate a then-expected 1,000 MW sale to Ontario, at a cost of $1.7 billion for the transmission line and converters. The building of this line, as well as Conawapa G.S., was cancelled when the Government of Ontario repudiated its power purchase agreement with MH (Ontario compensated MH for most of the costs expended by MH on the project, MH advised that a "relatively" low charge against retained earnings took place).

With the vast majority of Manitoba's population being in southern Manitoba and with the majority of MH's power generation located in northern Manitoba, the reliability of MH's transmission from the north is of the highest importance. In October 1996, a severe wind event destroyed towers on both Bipoles I and II, and the event, understandably, changed MH's view of the adequacy of Bipole I and II's reliability. Subsequently, MH has planned on constructing additional transmission to reduce the risk of "brown-outs" in southern Manitoba (a distinct possibility given an event such as 1996's wind storm).

In both MH's CEF-03 and CEF-04 forecasts, MH proposed building additional HVDC transmission on the east side of Lake Winnipeg. The new transmission was intended to address reliability concerns (the evident risk of a failure of either Bipole I or II, or both), and was also expected to reduce HVDC line losses. However, at that time, the proposed HVDC project cost was estimated to be only $350 to $400 million.

MH's CEF-05 and CEF-06 forecasts both included a $1.88 billion cost estimate for an east side of Lake Winnipeg routing, now including converting resources, while MH's CEF-07 increased the projected costs of Bipole III to reflect a western route, preferred by the Province. The cost estimate then rose to $2.248 billion, the additional cost reflecting the longer distance inherent with a "western" rather the "eastern" routing.

The switching to a western route from the initial plan for an eastern route came about as the result of concerns related to environmental matters, and general public, First Nation and American acceptability of an east side alignment for Bipole III. (The potential for another HVDC line through the Interlake, paralleling Bipole I and II, was rejected, being viewed as compounding existing risks).

The Board's understanding is that a reliability concern with respect to a substantial outage of Bipole I and II similar to the 1996 event could be met by several means. Two of these (applied to a forecast 2018/19 situation) being:

1. An outage of Bipole I and II up to 2018/19 (one that occurred during the summer peak season) could, it appears, be adequately served by the addition of 600 MW (plus reserve capacity) of CCCT thermal generation, or, alternatively by the in-service of Bipole III. Such an outage could be triggered by any of forest fires, wind storms and/or right of way flooding during the summer. Outage impacts are anticipated to be less in the spring and fall.

2. An outage of Bipole I and II (up to 2018/19) that occurring during the winter peak season could be met by the addition of 1,800 MW (plus reserve capacity) of CCCT thermal generation, or by Bipole III. Such an outage could result from winter blizzards and/or extreme cold temperatures. Ice storms are also a possibility, but less likely in mid-winter.

It seems that an outage shortfall would more probably be in the 800 to 1,500 MW range, which could be met either by new CCCT generation or Bipole III. (The Board understands that employing CCCT generation to meet the shortfall would disqualify the output from being certified as "green power" by Minnesota and Wisconsin.)

Failure of the existing Bipole (Bipole I and II) presents the greatest risk to Manitobans in the winter when domestic demand is generally at its highest. Peak winter domestic demands in 2018/19 are estimated in the order of 5000 MW. Loss of the existing Bipole would then require that domestic loads be served by AC connections (that are not dependant on the Bipole), existing thermal resources and emergency imports. Manitoba Hydro has approximately 1600 MW of hydro generation capacity not connected to Bipole, 370 MW of thermal resources and an emergency import capability of approximately 1500 MW. Therefore, to completely meet Manitoba's peak domestic loads in the winter, if Bipole III were not available Manitoba would need a gas plant having a capacity of approximately 1500 MW. This represents a worse-case scenario should a

Bipole failure coincide at the moment in time of the peak winter demand. In the summer, the situation is not as difficult as peak domestic summer demands are in the order of 3900 MW. In the absence of Bipole III failure of the Bipole lines in the summer would require a gas plant in the order of 400-500 MW.

A Question of Credibility and Process

While MH did not revise its new Bipole III (with converting station costs) estimate of $2.248 billion in either its CEF-08, CEF-09 or CEF-10 forecasts, even though MH then-raised its capital cost estimates for both Keeyask G.S. (by $0.9 billion) and Conawapa G.S. (by $1.3 billion), MH did cite ‘sticker shock’ as one of the reasons for the 25% jump in the estimated costs of the generating stations.

Subsequently, a September 2009 capital cost estimate for Bipole III surfaced in the fourth quarter of MH’s 2010/11 fiscal year, suggesting that the projected cost had increased to $3.9 billion. This Capital Project Justification Addendum (CPJ, a form employed by MH to record and, potentially, “approve” project cost estimates) was rejected by MH’s senior management, although it was signed on September 10, 2009 by two MH division vice-presidents. MH advised that while the estimate was discussed by senior management it was not brought forward to MH’s Board of Directors.

Ahead of that discovery, the matter of the cost estimate for Bipole III was reviewed by Board Counsel in discussion with Mr. Warden, MH’s Senior Vice-President and Chief Financial Officer. What follows are excerpts from the record of the hearing:

MH Senior Vice-President and Chief Financial Officer testified that an internal process exists with respect to changing construction cost estimates. Apparently, the division or divisions with responsibility for the proposed project “bring forward proposals for approval of (MH's) executive committee which, if approved, gets incorporated in the integrated financial forecast (IFF) …" and that "… in the case of Bipole 3, there was no revision approved".

So, from the time when CEF-07 was developed, and although four years had passed, during which the cost forecasts for Wuskwatim, Keeyask and Conawapa had substantially increased, MH "stayed with" with its forecast of $2.248 billion for Bipole III.

With respect to the CPJ signed by two MH vice-presidents which projected Bipole III at $3.9 billion, MH's Senior Vice-President and Chief Financial Officer initially testified, in response to a question from Board Counsel ("… with respect to Bipole 3, did the line divisions bring up changes in the capital forecast cost for Bipole 3 through the internal channels up to its vice-president?"), his response was "I don't know whether it made its way to the vice-president or not. It never made its way to executive committee though".

Following a follow-up question by Board Counsel: "Does the Board understand your previous evidence to be that the document (the CPJ that identified a forecast cost of $3.9 billion for Bipole 3, signed by two vice-presidents)) … never made its way to Manitoba Hydro's executive committee?", and, Mr. Warden testified "Yes, that's right", and, subsequently, "… it's the first time I've seen this document, it's never, been presented to the executive committee … it has no signatures. It's not signed by the … vice-president of transmission and power supply … until those signatures are affixed, this document is just a preliminary estimate which is subject to change…".

And, in response to Board Counsel's follow-up question "… you're suggesting that Hydro was not aware that on August 18th (2009) that … Hydro's transmission planning and design division was recommending a revision to the capital expenditure budget for

Bipole 3?", Mr. Warden responded "...it's the first time I've seen this document, it's never been presented to the executive committee, you'll note … it has no signatures … it's not signed by the vice-president of transmission and power supply … until those signatures are affixed, this document is just a preliminary estimate which is subject to changes".

Board Counsel then asked two more questions of Mr. Warden with respect to the above references CPJ: "… you're saying that until I showed (the CPJ, an unsigned version) to you this morning, you've never seen the document before?", and "… (would you) have expected to see this document in your capacity as a member of the executive committee if it had come up through the line divisions through the vice-presidents?".

And, Mr. Warden responded: "That's right", and "… I note that the division has not signed off. The process would be for the division to forward it to the respective vice-president to allow him the opportunity to challenge the document and – when he's satisfied – he or she, in this case he, but when he's satisfied with the document then it's brought forward for a review by the executive committee. That hasn't happened."

Board Counsel also asked Mr. Warden "What you're telling the Board … is that in 2007 and 2008 Manitoba Hydro saw no need to check to see whether the cost of Bipole 3 was escalating even though the costs for Conawapa and Keeyask were?" Mr. Warden responded "The process is to come up with an in-service cost for all projects and unless there's a reason to revise that estimate, there's no addendum (CPJ) brought forward. So it's not unusual to have a project that is estimated and unchanged" and "I'm telling you that we have an approved estimate of $2.2 billion for Bipole 3, and until it's officially revised that is the approved estimate … this is no different from any other capital estimate at MH in that respect. Until we have a number that we are satisfied with … a number that we can have confidence in we don't revise that number …".

Board Counsel concluded his cross-examination of Mr. Warden on this topic with the request “Mr. Warden, can you tell the Board whether (MH’s) Audit Committee was provided a copy of the … revised Bipole (3) calculation?” Mr. Warden responded “No, they were not … the Audit Committee would not typical receive these documents … they receive a very consolidated summary of all capital expenditure forecasts for … the twenty year financial document”.

Two days following this series of exchanges between Board Counsel and MH’s Senior Vice-President and Chief Financial Officer, MH tabled the CPJ referenced above in the dialogue between Board Counsel and Mr. Warden. The CPJ was signed by two vice-presidents, as Mr. Warden then stated:

“Mr. Tymofichuk, the Vice-President of Transmission, did in fact sign this document on September 10th of 2009 … and the Vice-President of Power Supply signed the document on the very same day … the CPJ would have been forwarded to Finance and Administration (the division for which Mr. Warden is responsible) for the preparation of an (executive committee) recommendation, which was done and was, in fact, forwarded to my office… I did not recall having seen the document, however I would have … been aware of the amount at that point in time … I would have consulted with Mr. Brennan as to how we would deal with it… of course, we were both concerned about the increase … and, therefore, did not move forward.”

Further, Mr. Warden reported: “I consulted again with Mr. Brennan just to make sure my memory and his memory was somewhat aligned, and following September of 2009, there would have been a lot of internal discussion about the amount of the capital cost estimate, or the revision to that estimate and it took approximately twelve months before we referred that to an outside consulting firm to resolve this issue for us, or at least to come up with an estimate that … we would have more comfort with”.

Thus, MH, accepting that estimated cost of Bipole III may be subject to a dramatic revision higher, in January 2011, MH sought an independent review of Bipole III costs by Rashwan (and Associates), the principal being a former MH employee.

While Rashwan & Associates reviewed the design concept and costs for the converter station and collector lines, the firm did not review the cost estimates for the HVDC transmission line. The firm concluded that MH could reduce Bipole III costs by eliminating a provision (included in the $3.9 billion estimate rejected by senior management) of a contingency reserve in case synchronous converters were required and, also, eliminate the escalation cost provisions usually employed by MH. Incorporating the changes suggested by the consultant, MH provided a revised CPJ with a $3.2 billion overall total costs for Bipole III, which was “accepted” by MH’s Board of Directors.

3.5.3 Project Economics

When prior to 2009, MH was negotiating with Northern States Power (NSP) on an extension of export sales contracts beyond MH’s fiscal year 2014/15, and with Minnesota Power (MP) and Wisconsin Public Service (WPS) for new sales contracts beyond 2020, the average value of new energy projected to be realized from MH’s planned new Keeyask G.S. was in the range of 6 to 7¢/kW.h. However, subsequent to negotiations that resulted in term sheets being entered into in 2007 and 2008, ahead of the global credit crisis and recession and the recognition of a substantial increase in the projected cost of Bipole III, the capital cost estimate for the construction of Keeyask increased (first by 25% as identified in CEF-10, and, later by another 18% in CEF-11, together representing an aggregate compounded increase of 50%).

Similarly, the expected average value of new energy arising from the planned construction and operation of Conawapa G.S. was in the range of 7¢/KWh in 2009. However, the estimated construction cost for the Conawapa generation station has since increased (by 25% in CEF-10 and by a further 25% in CEF-11, an aggregate increase of 56%).

Indications from publicly available documents from American regulatory hearings suggest that the term sheet negotiations carried out in 2007 and 2008 resulted in contract prices with NSP/WPS/MP that, at best, have not been increased in the NSP Agreement.

The evidence of the recent proceeding suggests that the subsequent and major project cost escalations for MH's preferred development plan will not be "covered" (met) by increases in export revenues. In short, it would appear that any profitability that may have appeared present with respect to these sales when the initial term sheets were entered into in 2007 and 2008, before the global recession and lower natural gas prices and industrial load, shale deposits, have been, at minimun, significantly reduced if not totally offset as the result of the capital cost increases (which were also not projected at the time of the signing of the term sheets).

3.5.4 Development Partnership Agreements

Manitoba Hydro has entered into agreements with First Nations with respect to the almost completed Wuskwatim Generation Station and the planned Keeyask Generation Station. The agreements provided the First Nations with the opportunity to participate in the equity ownership of the new generating stations, and represented a "new way" of approaching developments on lands occupied by First Nations, a way which involved negotiations ahead of construction, a way that allowed for First Nation approval and cooperation.

In both cases, taking into account the increases in construction costs from the original estimates, Wuskwatim – which is expected to be in operation in this fiscal year - and Keeyask, which is planned, are expected to produce power at or about 10¢/kWh.

According to MH's projected initial "Operating Statement", which was prepared by MH from the perspective of the partnership rather than MH's overall operation, Wuskwatim's probable initial years' revenue stream will be based on opportunity export prices.

MH's projected initial "Operating Statement" for the partnership, as reflected in IFF 09-1, projects revenues based on average opportunity export sales prices of about 7¢/KWh. Unfortunately, the export sale estimate is significantly higher than the current average MH is receiving for export opportunity sales to American counterparties, which appear to have been in the range of 2 to 3¢/kWh (2009/10 and 2010/11).

Accordingly, in the case of Wuskwatim and, if the Keeyask project is undertaken and completed, Keeyask's, revenue stream as well, at least initially, if based on current opportunity export prices or, in the case of Keeyask, an average of firm and opportunity export sales prices, may prove insufficient to fully meet costs.

Also, from the evidence available, it appears the allocation of expenditures to be incurred by MH favour the new partnerships, resulting in an even lower overall “economic” value of the new generation stations to MH overall (details discussed below under Board Findings).

3.6 Finance Expense

Finance expenses, as reported in MH’s audited accounts, were $401 million in 2009, representing over 29% of total operating expenses, and were forecast (MH’s IFF 09-1) to be $417 million in fiscal 2009/10. Actual finance expenses decreased to $373 million in fiscal 2009/10.

For the fiscal years 2007/08 through to and including 2009/10, actual finance expenses were approximately $76 million lower than that forecast in IFF 07-1, this the result of declining and relatively low interest rates during the period (largely the result of the global credit crisis and recession, and the slow recovery from the event), the rates particularly low for short term debt. MH forecast its overall finance expense at $413 million for fiscal 2010/11 and to increase to $468 million for fiscal 2011/12, representing approximately 25% of its annual operating expense.

The variation between actual and forecast is attributable to two factors, a growth in debt levels, more than offset by lower interest rates.

As it does with respect to certain OM&A expenses, MH capitalizes interest on all capital projects during construction, and only begins to record the costs as expenses once the project is complete and in service.

MH's finance expense for electric operation before capitalized interest is forecast to be $509 million for fiscal 2009/10, $417 million on a net basis after adjusting for capitalized interest of $92 million. MH forecasts net finance expense of $413 million in fiscal 2010/11 and $468 million in fiscal 2011/12, after capitalizing $131 million and $137 million, respectively.

As the major new generation and transmission projects commence construction, MH expects to capitalize a greater proportion of its finance costs, with $449 million or 43% of net interest expense being capitalized in its 2017/18 fiscal year.

MH's gross finance expense is forecasted to grow from $605 million in fiscal 2011/12 to $1,104 million by fiscal 2018/19; or, $674 million on a net basis after adjusting for capitalized interest of $430 million. Finance expense and capitalized interest for fiscal years 2009/10 through to fiscal 2018/19 are as follows:

Table 7

Finance Interest & Capitalized Interest

Finance Expense ($ millions)	**IFF MH09-1**									
For the years ended March 28/29	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Gross Finance Expense	$509	$544	$605	$635	$671	$752	$835	$953	$1,036	$1,104
(Less) Capitalized Interest	(92)	(131)	(137)	(110)	(144)	(208)	(306)	(408)	(449)	(430)
Total Finance Expense	$417	$413	$468	$525	$527	$544	$529	$545	$587	$674
% Capitalized	18%	24%	23%	17%	21%	28%	37%	43%	43%	39%

Based on MH's IFF 09-1, by its fiscal year 2028/29, MH forecasts to have capitalized, in aggregate, over $4.8 billion in interest costs to the in-service dates of the planned two new generation stations. When considering the estimated cost of MH's capital expenditure plans, it is important to consider financing costs, which are a significant element in capital intensive operations such as hydro-electric based utilities.

IFF 10-1 Update

MH provided a partially updated IFF MH 10-2 during the hearing, which reflects recently adopted increases in the capital costs of the Major Generation and Transmission projects in the order of $3.6 billion. In total, MH now projects an increase in its long-term debt from current levels by over $15 billion, to $23 billion, by 2029 ($5.3 billion higher than that forecast in IFF 09-1).

Given updated capital costs, capitalized finance expense will exceed $5 billion by 2029 (capitalized finance expense would be amortized over the expected service life of the assets).

Based on IFF 10-2, MH's forecast for finance expense was updated from $413 million to $393 million for fiscal 2010/11 and from $468 million to $411 million for fiscal 2011/12. The updated forecast reflects expected reduced interest rates in the near term, as rates have remained relatively low due to the slowness of the North American economic recovery. Finance expense is forecast to grow from an annual $411 million to over $1.5 billion by fiscal 2025/26, when the last of MH's planned major new Generation and Transmission projects, Conawapa, is expected to be in-service.

Based on the updated cost estimates in IFF 10-2, MH's debt is forecasted to grow from $8.7 billion as of March 31, 2011 to $22.9 billion as of March 31, 2030, an increase of $14.2 billion. The debt to equity ratio for 2029 has also changed, and, as indicated previously, MH now forecasts that implementation of its development plan (which includes the construction of new generation and transmission assets, from the 51:49 ratio projected in MH's IFF 09 forecast to 72:28 in its partially updated IFF–10 forecast, representing a material financial change from one forecast to the next. (The latest forecast includes the assumption of a series of 3.5% annual rate increases for a decade, to be followed by annual 2% rate increases.)

In MH's current forecast, the overall finance interest rate is projected to increase to 6.6% (excluding the 1% Provincial Debt Guarantee Fee) by fiscal 2016/17, and from then projected to remain constant at that rate through fiscal 2029/30. MH has not forecast any increase in long term interest rates beyond 2029/30.

4.0 Risk

4.1 Financial Forecasts

MH's initial Application, as indicated based on MH's IFF 09-1 forecast, is supported in part by 2008 export pricing forecasts, now at question, and capital expenditure estimates for Bipole III/Keeyask G.S./Conawapa G.S. totalling $13.1billion (CEF-09), those since updated to a current construction cost projection of $16.6 billion (IFF 10-2).

There has been a major increase in expected capital costs, which will be exacerbated by finance costs on the additional debt. Finance costs over the full term of the debt, can be expected to exceed the initial construction cost by a wide margin by the time the debt is fully repaid. MH's net export revenue assumptions have, essentially, remained unchanged from its IFF 09-1 forecast, this notwithstanding a 30-40% reduction in natural gas price forecasts that has developed since IFF 09-1 and MH's plans were established (reduced natural gas prices are a primary driver of lower spot prices on in the American electricity market, MISO, that MH operates in).

The now-forecast decrease in natural gas forecasts, which, if realized, would reduce CCCT natural gas generation costs by, say 25%, and affect, lower, at least spot and opportunity export sales prices, are not reflected in the financial forecasts placed by MH before the Board.

Again, the implication of the major reduction in actual and projected natural gas and spot and opportunity electricity prices in the MISO market is the suggestion of a significant pending drop from MH's currently forecast net export revenues. MH plans for firm export volumes to represent no more than 50% of overall export volumes, the other 50% to be represented by opportunity export sales - much of that at off-peak hours where pricing has been as low as 0.5 kWh over the last year and more.

While net income reduction scenarios are intended to illustrate the sensitivity of net income to changes in export and import pricing assumptions, MH declined to test, as requested by the Board, its export revenue forecast against assumptions of low opportunity export sales prices (related in part to lower natural gas prices, the current lack of indication of a price being placed on carbon and reduced industrial demand in the United States), both in response to Information Requests/Pre-Asked Questions from the Board or in MH's latest (IFF 10-2) financial forecasts (and despite ICF, a MH's expert witness, testimony on natural gas price decline and recent trends in the export market sales).

While MH's financial position as reflected in the partially updated IFF 10 reflects a marked decline from MH's projections of IFF 09-1 (covering a 20 year period), due to increased costs of Keeyask G.S., Conawapa G.S. and Bipole III, MH's current projection of its future financial position does not include the potential for lower overall export revenues.

As it is, MH's net income and retained earnings forecast as of fiscal 2028/29 – while subject to question and likely further adjustments, has changed, as follows:

Table 8
Changes in Net Income, Retained Earnings & Long Term Debt

	Net Income	**Retained Earnings**	**Long Term Debt**
IFF 09-1	$1,224M	$11.0B	$17.7B
IFF 10	$ 906M	$ 9.2B	$21.2B
OL 10-2	$ 741M	$ 7.7B	$23.0B

The changes that have been made by MH reflects revised and increased capital costs of over $2.3 billion for Keeyask G.S. and Conawapa G.S. (reflected in IFF 10-1) and an additional $0.9 billion increase in the capital cost of Bipole III (reflected in IFF 10-2). On a cumulative basis, the “accepted” increase in the capital cost of MH’s capital expenditure plans amount to $3.5 billion and results in a $3.3 billion reduction in MH’s IFF 10-2 projected retained earnings, and an increase in MH’s projected long term debt of over $5.3 billion compared to IFF 09-1.

Again, the accepted “decline” in MH’s forecast financial results does not take into account any implications that may be related to potential lower than forecast export prices.

4.2 Domestic Load Forecast

In MH’s IFF 09-1, the Corporation identified a projected decline from its 2008 GRA forecast of domestic demand of about 800-1,000 GWh. in its 10-year forecast of total domestic base load. Subsequently, and taking into account the slow recovery of industry (in the United States in particular), the closure of a Manitoba pulp and paper plant and the announced future closure of a smelter and refinery in Thompson, it could be argued that MH’s domestic load forecast should, or at least could, have been further reduced by 1,400-1,800 GWh./year.

As it is, MH’s latest forecast suggests total domestic loads of 25,700 GWh. in fiscal 2015/16 (down 1,400 GWh from IFF 09-1), and 27,000 GWh. in fiscal 2025/26 (down 1,700 GWh from IFF 09-1).

Almost the entire projected decline in domestic load forecasts rests with the industrial sector (or “Top Consumers” category), for which MH has forecast loads being down by

1,300 GWh./year from MH's IFF 09-1 forecast for fiscal 2015/16 through fiscal 2025/26. The major pulp and paper plant closure and "Primary Metal" industrial "cutbacks" could account for about 600 GWh/per year of the above decline. That noted, relying on notices issued by existing industrial companies concerning operational closures could add another 500 GWh/year of industrial demand loss after fiscal 2014/15.

Overall, and based on the evidence of the proceeding, growth prospects for the industrial sector, which currently account for about 1/3rd of annual domestic demand, appear to be very limited. MH testified that it was unaware of any new industrial customer planning to come on line over the current projection period, i.e. to fiscal 2028/29, not to say that either a new large industrial operation could choose to locate in Manitoba or an existing industrial concern expand.

Overall, MH's IFF 10 forecast does not forecast any reduction in total domestic revenue from the projections of IFF 09-1; MH's assumption being that load growth from residential or other classes will "make up" load losses as a result of industrial slow-downs or cut-backs. (The Board notes the potential that may lie with "electric" cars, though there are technological and economic issues to resolve (battery and "cold weather" among them).

MISO Market Impacts

MH's current actual export revenues (since the onset of the economic downturn in the fall of 2008 and the advent of enhanced forecasts of shale gas production and natural gas price declines) have reflected steep opportunity export price declines, from in excess of a 5¢/kWh range, that of the pre-economic slowdown period, to the 2 to 3¢/kWh. range.

Despite high river flows and excellent hydraulic generation potential, MH's overall export revenues remain depressed (due to not only low prices but also less volume that had been anticipated).

Going forward, export prices, taking into account low opportunity sales prices, may remain lower, perhaps considerably lower, than what is currently forecast by MH. The advent of commercially extractable shale gas and the absence in the near term and delay in the evolution of CO_2 emission pricing is reflected in ICF's revised long-term natural prices being 30% to 40% lower than the firm forecast in 2008.

Because MH exports "compete" with CCCT natural gas generation in the peak and shoulder period, and MH's exports "compete" with incremental coal and wind generation in off-peak periods, the lower natural gas prices could, hypothetically, result in a substantial reduction from what MH currently forecasts as its expected future net export revenues.

With MH declining to provide additional lower export price scenarios, for which MH was asked, the Board can only impute what domestic revenue requirements could be in the next 20 years. Shortfalls from expected net export revenue will be reflected in domestic rates, if MH's financial targets (particularly debt to equity) remain as is.

4.3 Export Revenue Pricing Assumptions

MH sales into the U.S. MISO Market over the last decade can be summarized as follows:

Table 9

MH's Exports into MISO & Canadian Markets (GW.h)

Year	**Dependable**	**Opportunity**	**Total**	**CDN Sales[1]**	**Total**
2000/01	4,895	4,511	9,406	3,047	12,153
2001/02	4,767	5,083	9,850	2,449	12,299
2002/03	4,947	2,713	7,660	2,075	9,735
2003/04	5,245	507	5,752	1,214	6,966
2004/05	5,683	3,218	8,851	1,680	10,431
2005/06	4,044	8,879	12,923	1,424	14,347
2006/07	3,654	5,877	9,531	373	9,904
2008/09	3,921	7,332	11,053	682	11,735
2009/10	4,087	6,071	10,158	418	10,576
2010/11	2,613	6,218	8,831	336	9,167

[1]Non-merchant sales from MH's own resources.

Typically, MH has purchased wind and thermally generated energy to support its hydraulic generation in the range of 1,500 to 3,000 GWh: drought period exceptions occurred in fiscal 2002/03, at 3,800 GWh, and in 2003/04, at 10,500 GWh.

With only the existing transmission tie-lines to rely upon, MH is generally limited to, assuming adequate water levels, about 7,000 GWh./yr of peak energy sales. Except for fiscal 2008/09, peak firm and opportunity sales over the last 10 years have accounted for 2/3^{rds} of MH's export; meaning the other 1/3rd of total export sales serve off-peak markets (in both MISO and Canada).

During that period, MH achieved average annual export prices of about 5¢/kWh. From 2004/05 to 2008/09 firm contract prices were 5 to 6¢/kWh, opportunity peak prices were 6.5 to 7.0¢/kWh, and opportunity off-peak export sales came at prices in the range of 2.5 to 3.5¢/KWh.

Unfortunately, this situation changed in 2009/10 after MH's IFF 09-1 had been filed. In IFF 09-1 and IFF 10 MH assumed average export revenue rates as follows:

Table 10

Forecasted Average Expert Revenue Rates

Fiscal Year	**IFF 09-1**	**IFF 10**
	(¢/kWh)	**(¢/kWh)**
2010/11	4.10	3.26
2014/15	7.41	6.63
2015/16	9.09	8.11
2019/20	10.56	10.84
2020/21	10.66	11.12
2021/22	10.94	11.13
2025/26	12.25	12.20
2026/27	12.64	12.58
2028/29	13.45	13.45

MH's IFF 09-1 forecast of export prices reflect the input (which occurred in or before 2008) of a panel of external consultants engaged by MH. ICF, one member of the panel, provided evidence in this proceeding that the natural gas prices employed by ICF's forecast in 2008 are 30-40% higher than ICF's current forecasts, and that, as a result, MH's previously forecast spot and opportunity electricity prices for the MISO market could be lower.

A comparison of MH's IFF assumptions to more current data as to Single Cycle Combustion Turbine (SCCT) thermal generation costs confirms that MH did not alter its export energy price forecasts in its IFF 10 projection from those of its IFF 09-1 forecast.

The chart which follows largely results from the expected change in natural gas prices and provides a comparison of four various export price scenarios, namely:

- Scenario #1 – MH's IFF 09-1 Export Revenue Prices
- Scenario #2 – MH's IFF 10 Export Revenue Prices
- Scenario #3 – 0.75 x MH's IFF 09-1 Export Prices
- Scenario #4 – PUB/MH Pre-Ask #4 Export Price Scenario

The first two scenarios are extracted from MH's filed export revenue price assumptions for IFF 09-1 and IFF 10. Scenario #3 at 75% of IFF 09-1 prices is intended to reflect the 35 to 40% reduction in ICF's natural gas price forecasts as of 2008 and 2010. Scenario #4 is drawn from PUB/MH – Pre-ask #4 (which MH declined to respond to).

The export revenue rates illustrated for the 20 years of forecast show very little change between IFF 09-1 and IFF 10, particularly from 2019/20 on-ward. As expected a 25% revenue rate reduction in Scenario #3 would see 8 to 10¢kWh export electricity prices after 2019/20 to 2029/30. This could be considered a conservative position, relative to Scenario #4 which at about 65% of IFF 09-1 prices is more pessimistic.

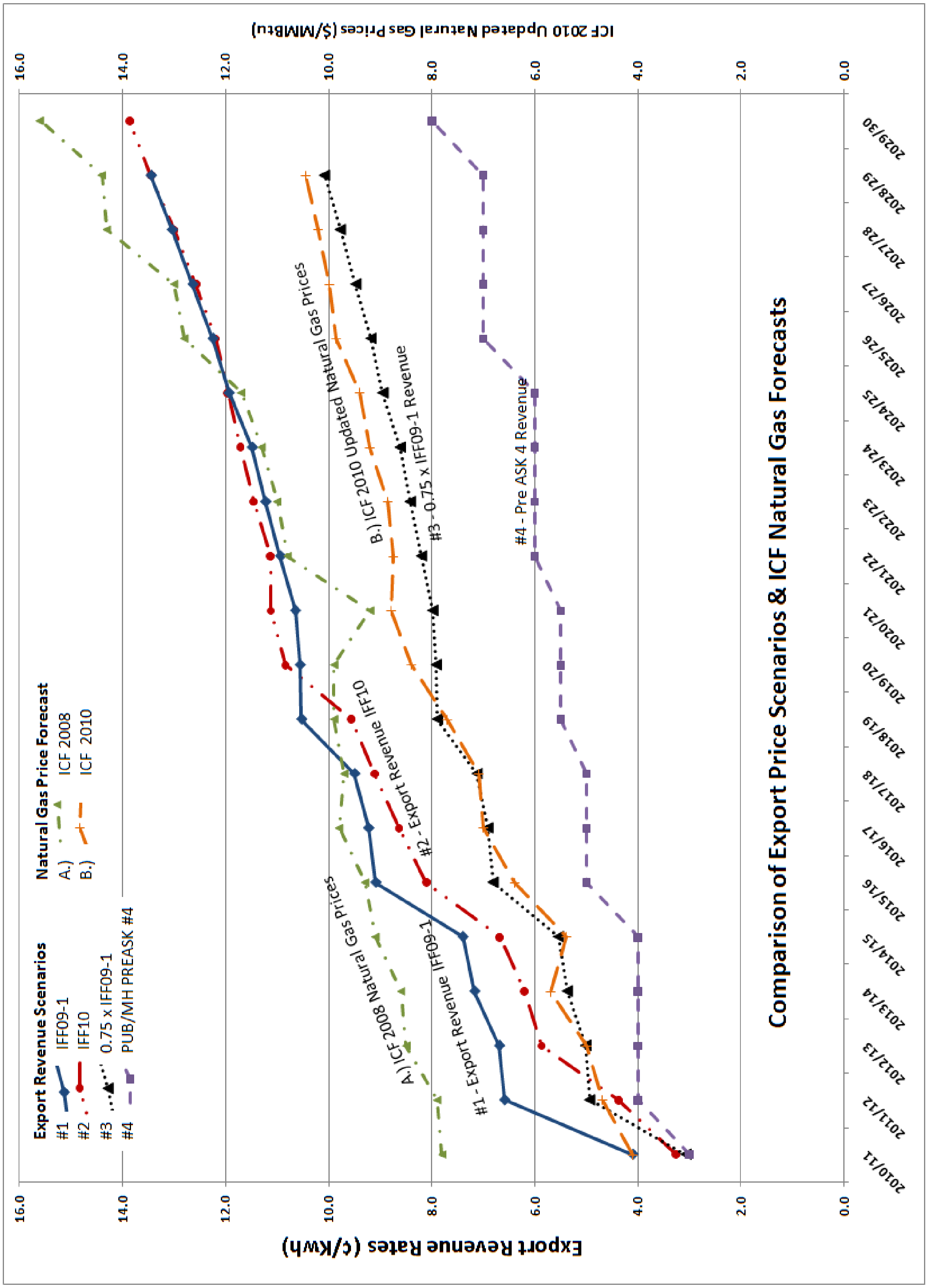
Also indicated as Scenarios A and B on the chart are the natural gas price forecast for 2008 and 2010 drawn from ICF presentations and subsequent exhibits.

ICF now expects natural gas prices to remain below \$6/MMBtu until fiscal 2014/15, then remain below \$8/MMBtu until 2018/19, and not achieve \$10/MMBtu before 2026/27. (As a comparison, in the last decade natural gas prices have exceeded \$10/MMBtu on at least two occasions – following hurricanes Katrina and Rita in 2005, natural gas prices soared to in excess of \$15/MMBtu – these events precede the advent of shale gas production.)

In 2008, when MH developed its export price forecast for IFF 09-1, natural gas prices were upwards of \$7/MMBtu, and were expected to progressively rise, achieving about \$10/MMBtu (as CO_2 emissions factors kicked in circa 2015), and rising further to \$15/MMBtu by 2028/29. CCCT thermal generation was then generally expected to dominate the peak period electricity generation market, and to a lesser extent compete for base load with coal generation. Other new energy resources for MISO, such as MH exports and northern states' wind farms would presumably be constrained price-wise by now expected lower CCCT operating costs.

Chart 1

Comparison of Export Price Scenarios & ICF Natural Gas Forecasts



According to the public record, MH expects to achieve on average at least 8.7¢/kWh for peak "firm" sales from its new export contracts, from 2015/16 onward. Even allowing for some escalation (MH advised of a formula within its new contracts that allow for price escalation related to a partial recognition of general inflation), this "expected" average price is at least 10% lower than MH's IFF 09-1 and IFF 10 assumptions for average export sales prices.

Intuitively this suggests that MH's spot and opportunity export sales (the average of peak and off-peak) may have to average about 1-2¢/kWh higher than the "firm" peak prices encapsulated in its contracts to meet the revenue forecasts made by MH. The historical record provides no evidence of such a past situation.

4.4 Export Contracts

4.4.1 Current Export Contracts

Currently, MH has firm long term obligations under Northern States Power (NSP) contract that extends from 2005-2015 and involves 500 MW. The contract requires MH to provide 500 MW to NSP or an annual supply of 2,100 GWh of "5x16" energy (five days a week, sixteen hours each day). The contract extends to 2015 with fixed pricing. Although this obligation could, theoretically and presumably, be reduced under drought conditions more severe than the worst case on record, the Board has not been in a position to review the contract.

Yet, according to NSP's public documents, as filed in the United States, MH has not, at least to the date of the filing of those documents, curtailed supply under this contract, and NSP has indicated to its regulator that it does not expect MH to ever curtail supply.

During the 2003/04 drought, MH continued to supply "firm" power to its American counterparties, despite the Board's understanding that the Corporation had the right to curtail supply in the event of a drought, but that it chose not to curtail to preserve the business arrangement and MH's reputation as a reliable supplier. In any case, if there was misunderstanding, that contention was corrected by MH in this proceeding, wherein MH indicated that the contract did not allow for the Corporation to curtail due to the drought, and that it had an obligation to supply that it could not set aside.

Additionally MH has entered into diversity agreements out to 2015 with NSP (and others) for about 350 MW of capacity. The arrangement, as reported, provides for a summer-winter exchange of capacity availability (variable energy as/when required to be supplied and billed at market prices). When MH imports power from the United States that power arises largely from thermal (coal primarily) generation, while MH exports hydro-electric power to the United States.

MH also annually enters into bilateral agreements with various parties in the MISO region to supply summer (5x16) firm energy. Typically these arrangements involve about 1,000 GWh./year of energy at prices that are annually adjusted.

As well, MH engages in day-ahead and real-time opportunity sales into the MISO market. These forays have, in above average flow years (since 2003/04), been in the 3,000 to 7,000 GWh/year range. Prices for such sales have dropped sharply since the fall of 2008, and now average about 3¢/KWh. (average includes both peak and off-peak sales).

4.4.2 Future Export Contracts

MH has recently announced that it has entered into new export contracts (subject to regulatory approval in both the United States and Canada and dependent on MH proceeding with its preferred capital development plan, pertaining to periods beyond 2015.

These include:

(i) Northern States Power (NSP)

NSP [2015 to 2025] - 375/325MW summer (5x16) winter (5x12) – fixed price/firm

- 350MW Diversity Exchange Agreement – market price based
- 125MW summer (5x16) winter (5x12) – fixed price/firm

(Defined energy obligation: 2100 GWh)

(ii) Minnesota Power (MP)

MP [2020 to 2035] - 250MW summer/winter (5x16) - fixed price/firm

- 250MW summer/winter weekend (2x16) - market price based

(Defined energy obligation: 1,400 GWh.)

(iii) Wisconsin Public Service (WPS)

WPS [2020 to 2035] – 100MW summer/winter (5x16) - fixed price/firm

- 100MW summer/winter weekend (2x16) – market price based

(Defined energy obligation: 600 GWh)

While individual contract specifics on pricing have been deemed confidential by MH, and have yet to be shared with the Board, ICF, an expert retained by MH, presented information at the proceeding suggesting MH's combined capacity and energy prices were in the range of about 8.7¢/kWh, on average, for firm (peak) energy.

When price escalation is factored in, the price suggested appears to represent about 90% of MH's IFF 09-1 export price assumptions. Consequently, if MH's forecast export prices for its IFF 09-1 are "reasonable", the required assumption appears to be that the average price of spot and opportunity export sales was expected to be higher than the contract values.

Without access to the unredacted contracts, it is not possible for the Board to either agree or disagree with either MH's views on pricing or that of its various consultants' on the adequacy of any curtailment or 'adverse water' clauses that may reside within the contracts.

However, and significantly, the evidence suggests that MH cannot reduce summer sales to its American counterparty under the 'adverse water' clause cited by MH at the proceeding. It is unclear at this time, and without present access to the contracts, as to what extent contract provisions mitigate against the likely or possible cost consequences associated with drought conditions.

From the evidence provided, MH's exports to NSP after 2015 come with environmental attributes included in the negotiated price – i.e. environmental attributes of power supplied by MH to its American counterparties are to be attributed to the American counterparties (the exact conditions of the Clean Energy Clause were redacted from the information placed on the record of the hearing).

What does appear clear is that there are no defined Clean Energy premiums to be paid MH by NSP. Rather, any future CO_2 premium costs would increase MH's import and thermal generation costs.

4.5 Drought

One of the major risks faced by MH is drought. Lack of available water during a drought severely limits MH's power supply.

Despite commitments made by MH to provide the Board, by April 1, 2011, a formal "written" Drought Preparedness Plan, nothing has been filed. Nonetheless, MH asserts that drought planning is a constant activity within the Corporation and is incorporated in its business processes. Both ICF and the Independent Experts recommended a formal written plan be prepared.

In 2003/04, MH experienced drought conditions that resulted in a net loss of $436 million. Despite the evident cost consequences of drought conditions for a utility relying on hydro-electric generation and involved in significant power exchanges with American utilities, with commitments and/or understandings with respect to supply involved, MH has suggested that a written Drought Preparations Plan would be redundant given MH's current practices, which were reported to have been employed in 2003/04.

Despite the Board having directed MH to engage an independent risk expert to conduct a post-audit of MH's actions through the drought, no such report was filed. And, no evidence was presented either at a prior or recent hearing indicating that MH undertook a detailed assessment of its water resource management and decisions employed in 2003/04.

MH's past planning position is that preparing for a five-year drought (as defined by the specific historical period from 1987/88 to 1991/93) provides an adequate drought risk stress test. It remains unclear as to what degree of shortage pricing, such as experienced in 2003/04, should be anticipated.

MH has projected that the financial consequences of a five-year drought to be in the range of $2.0 billion in reduced retained earnings ($2.4 billion when increased finance costs are considered). MH indicated that if shortage/ high import price situation coincided with a drought period this could increase the cost of a five year drought from $2.0 billion to $2.5 billion (with finance costs included, an even larger overall shortfall).

The Independent Experts also projected the cost of a five-year drought, and arrived at an estimate of $1.6 billion, with a $2.0 billion cost anticipated in the case of a seven-year drought. However, when an assumption of high import prices are incorporated and coincide, and are modelled as being sustained throughout the drought periods, the estimated cost of a drought may, in the view of the Board, be significantly higher.

The Independent Experts also recommended that MH not solely rely on retained earnings as the only buffer against a drought, but to also incorporate a reservoir storage buffer as a mitigation measure.

Evidence was presented at the hearing modelling varying duration of droughts, including efforts to ascertain the implications of droughts with durations longer than five years. During the period of 1928 to 1941, MH experienced low water flow conditions in 12 of the 14 years (this reflective of an extreme drought condition). While no estimate was provided as to the impact on MH if such a prolonged drought now occurred, it seems obvious that a repeat of such difficult conditions would have a significant financial impact on MH.

A similar situation occurred during the 1980/81 to 1991/92 period, with ten out of 12-years of drought, but the financial consequences at that time were much lower than would now be expected, particularly if the new export contracts were consummated. During that period, MH's exports to the United States were not a major factor.

On the issue of drought frequency, it may not be essential to define the return period of a 5-year or 7-year drought (by "return period", the concept is how many fiscal periods would be expected to have to occur before the losses were recovered). However, it is appropriate that MH's business strategies be tested against the entire historical drought experience, an experience that includes the 1928-1941 period, when 12 of 14 years were drought conditions.

Even after establishing the volumetric drought risk, the question that remains is what import prices should be expected in the case of an extended period of low hydraulic generation. The concept of shortage pricing is broadly acknowledged (when a shortage develops and the supplier seeks to meet demand through alternate sources, the price of obtaining the supply may be far higher than the normal cost of production for the supplier), but differences exist on whether volumetric shortfalls and shortage pricing are mutually exclusive and independently variable, or whether the two events are closely linked.

It could be postulated that for MH's export business shortage pricing is unlikely to occur and only be an issue in the absence of adverse or low water supply situations. In negotiating long term contracts, again yet to be shared with the Board, MH has advised that it has obtained 'price cap' clauses applying to the purchase costs of energy or buyback costs that might be occasioned under 'adverse water' conditions. This suggests that shortage pricing could be a serious issue, otherwise why would MH simply not rely solely on the MISO market for imports as well as exports?

Droughts are expected to result in negative financial implications when MH's long term contracts are reliant only on hydraulic generation (and do not involve thermal and wind generation). In addition to being less profitable, dependable energy sales, and also peak opportunity sales, in volumes in excess of hydraulic generation can involve comparably priced energy purchases under the best of circumstances (while they can result in significantly greater financial losses for MH under adverse – low water flow - water conditions).

4.6 Financial Risks

Among the many and diverse high consequence risks faced by the Corporation (risks which include drought, the loss of export markets, and infrastructure – transmission or generation - failure), MH has also identified financial risks associated with interest rates and exchange rate volatility.

MH has indicated that a 1% upward change in interest rates can be expected to have a $170 million negative impact on its net income over an eleven year period. The analysis arriving at that forecast was based on using MH's IFF 07-1 as the base case and applying a 1% increase in interest rates to derive the interest rate risk scenario. MH compared the effect to its IFF 07-1 net income forecast for the fiscal period 2007/08 to 2017/18 (that being the base case employed to test the resultant total net income impact of a 1% upward and sustained movement in interest rates).

MH also provided an updated risk analysis for 2010, with an updated cost consequence related to a change in interest rates. The financial exposure risk was updated to approximately $430 million negative for a 1% increase in interest rates over a ten-year period, this up substantially from the previous estimate of $170 million.

The current higher estimate was likely based on MH's IFF 09–1 and, accordingly, has not reflected the more recent projection of higher capital costs for MH's planned major generation and transmission projects (the increase in projected capital costs being in the order of $3.5 billion).

Accordingly, the negative financial consequence of an increase in interest rates of 1% is likely to be even higher than the current estimate of $430 million over a 10-year period, and would have further negative financial implications over a 20-year term through to and including fiscal 2029/30.

Currently, MH has in excess of $7 billion in long term debt, the majority of which is locked in for terms as long as 30 years. As previously indicated, MH is planning, and acting currently on those plans – expending significant sums ahead of regulatory approvals, to undertake an ambitious capital expansion program requiring additional borrowings of $15 billion or so over the next fifteen years.)

With current interest rates, particularly short-term rates, being quite low, MH is forecasting long term interest rates to be 6.6% (excluding the provincial debt guarantee fee of 1%) by fiscal 2016/17, with that rate to remain constant to and including fiscal 2029/30.

MH is also at risk to economic losses due to unfavourable foreign exchange movements with respect to the Canadian dollar (CDN) vis a vis the United States dollar (USD).

Export sales to U.S. counterparties are denominated in USD, as is a component of MH's long term debt. MH's risk exposure to USD/CDN changes primarily arise through the sale and purchase of electricity and fuel into and from U.S. firms.

MH attempts to "manage"/offset the exchange risk through a long-term "natural hedge" involving USD cash inflows from export revenues and USD cash outflows for long-term debt interest and principal payments. MH's Exposure Management Program (EMP) is designed to match cash outflows for USD debt [principal and interest] with cash inflows from net exports sales (export sales net of U.S. fuel and power purchases).

To bridge the timing differences between the inflows and outflows of USD requirements, MH may utilize various financial instruments, including derivative foreign exchange contracts, debt, investments, swaps etc. Nonetheless, MH has estimated the potential negative financial impact of a reduction in the value of USD compared to CDN to be approximately $125 million over a ten-year period.

While presently CDN is valued above par with USD, MH is forecasting the US-CAD exchange rate to rise to 1.04 by 2012/13, 1.09 by 2014/15, and to 1.11 by 2015/16, with the 1.11 ratio to continue through to the end of MH's 20-year forecast. (In other words, MH's currency forecast has the Canadian dollar below par with the USD throughout the twenty year period.)

Currently, MH's accounts include within its equity component Accumulated Other Comprehensive Income (AOCI), that balance largely represented by "unrealized" gains on foreign exchange. MH borrowed funds in USD in the past at exchange rates much different than is currently the case, and the "current market value" ascribed to those debts is much lower expressed in CDN that it was when the debt was incurred. This situation also is assisting MH when it pays interest on American debt, converted to CDN the cost is less than the "coupon rate" of the debt.

As present unrealized gains on foreign exchange are realized through annual payments of principal and interest, the "gains" are expected to offset by the countervailing effect of exports to American counterparties being priced in USD. In short, it would appear that AOCI is but a temporary "credit" component of equity as its value will diminish and eventual be extinguished through lower values of export sales that would have been the case if the CDN/USD ratio had not changed.

And, going forward, while export sales to American counterparties will continue to be priced in USD, or so it appears, there is no guarantee that further downward movements in the USD ratio to the CDN to offset the loss of revenue will occur. As well, there is no guarantee that MH will continue to borrow in USD at the same rate as it has in the past.

A more detailed discussion and analysis of the financial risks, interest rates and currency, faced by MH will be provided in the second Order.

4.7 Power Resource Modelling

MH employs a fairly extensive array of models to define energy, energy demand and net revenue streams. MH models were the focus of much study and commentary ever since the 2003/04 drought event, and particularly in the recent proceeding.

There appears to be a reasonable consensus (among the various experts that testified in the hearing) that MH's models are more effective in defining and considering the effects of high flow circumstances than defining and considering the effects of low flow circumstances. Except for MH's 2003/04 fiscal year, the available data essentially reflects above average water flow situations. Prior to 2005/06, market price information did not readily provide peak and off-peak volume and price data, inhibiting the back-testing of drought events such as the drought of 2003/04.

A common theme in the various reviews was that the models lacked hydrologic predictive components and instead relied on antecedent forecasting. Lack of consistency in model assumptions was also a concern.

The use of the assumption of "perfect foresight" in MH's SPLASH modeling allows reservoirs to be drawn down to zero storage; a situation that would not be acceptable in MH's HERMES model. The result is that SPLASH-based IFF revenue projections may be overstated.

Unlike SPLASH, HERMES employs only "limited foresight": that is, hydrologic run-off predictions based on previous precipitation levels is not a direct factor in MH's forecasting of hydrologic generation. Evaporation losses are not actually determined on an ongoing basis, rather average conditions apparently are assumed for this and ungauged local stream flows.

It was noted by the Independent Experts that MH's various models (SPLASH/HERMES/PRISM, etc.) lack an integrated platform. The Independent Experts suggested that the lack of a common/integrated platform left uncertainty as to the consistency of the assumptions employed in the various models.

All of MH's recent external reviews (particularly KPMG, Independent Consultants and NYC) focused on the need for MH managing a more transparent operation, particularly as it relates to having an effective "middle office" function. The middle office is intended to operate as a check to the sales operation, to ensure that sale and purchase decisions from external counterparties are in MH's best interests. A strong middle office, with a defined mandate and a broader expertise in staffing, was seen as an essential step to assure appropriate MH Power Resource Management, Drought Mitigation and the derivation of other risk element evaluations.

Again, in the second Order more will be said on this topic.

4.8 Interveners and Positions on Rates

CAC/MSOS submitted that the Board eliminate the 2% interim rate increase for 2011/12, or at least cut the increase in half. CAC/MSOS asserts that the evidence does not support the increase.

MIPUG submitted that the Board should given final approval to the 2010 – 2.9% and 2011- 2.0% interim increases as granted, but with proposed rate adjustments between customer classes incorporated to reflect MIPUG's position respecting required rebalancing based on differences in revenue to cost coverage ratios.

RCM/TREE submitted that the Board should give final approval to the 2010 – 2.9% and 2011 – 2% interim increases as granted, and requested by MH, and the Board should add a further 0.9 of 1% from the date of the Board's order for a rate increase of 2.9% forward for the balance of the 2011/12 year. RCM/TREE also proposed rate structure changes for the residential class.

The City of Winnipeg submitted, in agreement with the position of MH, that no increase in rates be applied to its rate category of Area and Roadway Lighting; the City took no position on the general issue of rate increases.

SCO submitted that if the Board approves the interim rate increases for 2010/11 and 2011/12, those revenues arising from the increases should be set aside and earmarked for all Manitoba First Nations, to be used as a compensation fund. MKO made no submissions.

It is fair to say that, in general, all participants await the outcome of MH's pending Cost of Service Study (COSS), and all interveners see the need to have further input on rate design/rate class issues. MH seeks across the board increases at this time (as noted), excluding Area and Roadway Lighting, given that the COSS is not complete.

5.0 Board Findings

Two Rate Orders

As previously indicated, on December 1, 2009, MH filed its 2010/11 and 2011/12 GRA.

The proceeding that followed included a detailed review of MH's risks and risk management as practised by MH, and spanned a period of 19 months and involved 41 hearing dates (not including pre-hearing conferences and three days of closing statements) and the filing of 27 binders of information (including over 5,300 filed interrogatory responses, over 200 exhibits, and testimony from several expert witnesses), all providing an extensive record of the proceeding for the Board to evaluate.

While the record of the hearing is extensive, it is, unfortunately, not complete. MH has failed to provide export contracts, financial projections, alternative development scenarios and other information requested by the Board, despite the Board's need for the information to allow for a finalization of various interim decisions, and the Board's commitment to maintain commercially sensitive information confidential.

During the course of the proceeding, and particularly concerned with the risks faced by the Corporation in difficult and uncertain economic conditions, the Board granted MH interim rate increases of 2.9% effective April 1, 2010 and 2% (rather than the 2.9% applied for) effective April 1, 2011, both of which Orders MH now requests be finalized.

In addition, MH has requested a further 0.9% rate increase; in seeking the additional 0.9% MH requested that the additional rate increase be approved effective August 1, 2011.

To respond to MH's requests, the Board will issue two Rate Orders. This first Order addresses issues on certain rate and risk related issues, with the second Order to provide a much more detailed and comprehensive review of the issues before the Board (the issuance date and comprehensiveness of the second Order cannot be assured at this time, dependent in part on whether the Board receives information it deems necessary and within its jurisdiction to receive).

Rates

Particularly since the 2003/04 drought, the Board, MH, along with certain Interveners, have recognized the importance of MH having an adequate and stable financial structure.

While the Board retains serious concerns with how MH calculates the equity component of its debt and equity ratio, the attainment of MH's target ratio of 75:25 (debt to equity) was not, at the 2008 GRA proceeding, envisioned to occur within the then 10-year planning horizon. And, at that time, the anticipated result of achieving the 75:25 target was the expectation of modest annual rate increases to follow, to reflect general inflationary pressures, no more.

While, with the filing of this GRA, MH asserts the achievement of the 75:25 debt-to-equity target, this coming four years in advance of the most previous target date, rather than annual "inflation level" rate increases to follow, MH is now seeking rate increases of 2.9% in both 2010/11 and 2011/12, and projects further rate increases of 3.5% per year for each year of the following decade, to be followed by annual rate increases of 2%, the 2% level coinciding with the target of the Bank of Canada for inflation.

The years of 2.9% and 3.5% projected annual rate increases coincide with the decade that MH would have marked by the construction of major new generation and transmission investments, advanced ahead of Manitoba demand requirements to meet expected and presumably profitable U.S. export contracts.

MH acknowledges that its operations involve risk in virtually every aspect of the Corporation's operations. As one and a major component of a plan to mitigate risks, the assumption has been to achieve the 75:25 debt to equity ratio and hold it there through inflation level annual increases thereafter.

However, as indicated above, MH's planned "decade of investment" (to involve major capital construction at a cost of $20 billion or more), despite larger annual rate increases than previously thought required, once the 75:25 debt to equity ratio was reached, is now projected by MH to deteriorate to 83:17, before fully recovering following several years after the in-service dates of the planned major construction.

In determining whether or not, particularly in the circumstances now in "play", MH's capital structure and rate proposals mitigate the various and serious risks faced by the Corporation, the Board reviewed MH's risks and risk management in this proceeding.

It has become very clear that a major risk is associated with MH's planned "decade of investment" (to be supported by sought-after long-term energy sales to American counterparties). The capital costs of the new generating stations, to be built well ahead of domestic load requirements, and transmission are very high, and while the planned new export contracts bring significant obligations they, perhaps, do not produce enough assured revenue to avoid higher domestic rate increases than may be acceptable.

Manitoba Hydro's historical record of having domestic rates that are the lowest or among the lowest in North America has been described as the *Manitoba Advantage*. And, despite these low rates, Manitoba's cold weather and the lack of province-wide availability of natural gas mean that some customers, particularly lower income households, receive electricity bills that they have difficulty paying (some 80,000 or so accounts are apparently delinquent following any billing date – being delinquent does not mean the account ends up written-down or off, but it does infer late payment fees).

In addition, large industrial consumers, represented by presenters at MH GRA hearings, have often cited the importance of Manitoba retaining low electricity rates to their operations remaining and expanding in the Province.

Rate increases above the rate of inflation are regularly opposed by consumer advocates, including an Intervener to this hearing. And, MH currently projects just that through its planned "decade of investment". It is far from clear whether the risk tolerance level of MH matches that of its customers, particularly its household and industrial customers.

It is also far from clear for the Board, which has yet to receive (in confidence) MH’s export contracts, whether MH’s proposed new export arrangements can be expected, if not assured, to generate enough additional revenue to fully meet the cost of advancing new generation ahead of domestic need, or whether, in the end, domestic customers will end up subsidizing exports to the U.S.

And, with respect to Bipole III, while the Board readily identifies with the vulnerability of southern Manitoba, in particular, to outages caused by the failure of Bipole I or II or both, and understands the Corporation’s focus on reliability, the Board is, despite the hearing, still not assured that the costs of the new transmission will be met by net export profits and not have to be absorbed by domestic customers through rate increases higher than those now projected.

The Board notes that MH’s plan (major construction and new export sales) preceded the negative economic events of the summer and fall of 2008, which involved a credit crisis and the beginning of a global recession that still “lingers”. It also preceded changes in the American political landscape, where the focus has moved from “climate change” and efforts to reduce green house gas (GHG) emissions to pressing economic and budgetary challenges.

This said, the Board observes that American politics is a volatile environment and a resurgence of support for measures to reduce GHG emissions could reappear in the future. Currently, America is locked in a critical debate centered around its federal budget and an ongoing slow recovery from the recession.

However, it is the Board’s understanding that MH’s recent export contracts, conditional upon regulatory approval and the construction of new generation and transmission by MH and the construction of new transmission by the American utility counterparties, provide for the exporting of power for a considerable length of time with any “clean energy” credit that could develop to accrue to the benefit of the American counterparties, not MH.

To further complicate the situation, since MH entered into term sheets in 2007 and 2008 with American counterparties, new engineering methodology has allowed for the affordable extraction of natural gas from North American shale deposits, further depressing the price of natural gas (already depressed by the slow recovery from the recession), which affects the marginal cost of production of electricity within the American component of the MISO market.

(The Board notes that the production of shale gas from shale deposits has been associated with negative environmental consequences primarily associated with the use of water and the condition of such water after its employment in gas production. Accordingly, the Board cannot be “sure” that the shale gas “revolution”, described as a “game changer” by academics, producers and others, will be realized as now anticipated.)

Yet, despite all of the changes that have occurred since MH developed and put into action its preferred development plan, which counts on new export contracts, changes which also extend to the rise of the Canadian dollar to above par with the respect to the American dollar, and hyper-inflation with respect to major construction projects, MH has not changed its “game plan”.

The main question before this Board is whether MH’s “game plan” will require higher domestic rates than MH projects. At this point, and with the information that MH has provided the Board, while the “jury is still out” the Board has serious concerns.

Through this proceeding, the Board gained the understanding that the approximate cost of creating and supplying the energy to service the planned export contracts from major new generation projects is estimated to be in excess of $0.10/kW.h. However, the record of the proceeding also indicates that the expected export prices, which include not only firm energy obligations and opportunity export sales, may not, in aggregate, be sufficient to cover the cost of advancing the projects ahead of domestic demand, leaving a financial shortfall to be reflected in the rates of domestic ratepayers (that being in addition to the rate increases currently forecast by MH).

In order to appropriately assess the risks faced by domestic Manitoba customers. The Board first requested and later subpoenaed copies of MH's new export contracts, this to allow the Board to assess whether the prices and the terms in the contracts either mitigate or increase risks for domestic ratepayers. The obtaining of the export contracts is currently subject to procedural motions; to-date, the Board has not yet been provided with the specific information requested.

The appropriateness of the current 75:25 debt-to-equity target is predicated on the Board's understanding of MH's risk profile, and, as well, the Board's acceptance of MH's calculation of its equity. As to the terms of the new export contracts and the implications for the risks assumed and rates to be assessed domestic ratepayers, these have not been fully assessed by the Board, given the withholding of the subpoenaed contracts and the failure of MH to provide a fully updated IFF and additional development scenarios.

Thus, the Board is currently unable to determine whether the interim and the requested additional rates are just and reasonable.

Therefore the rate increases granted on an interim basis in this proceeding will remain interim, subject to finalization, amendment or further continuation as interim until such time as the Board has sufficient information to reach a further decision. As well, and for the same reason, the additional rate increase sought of 0.9% across all rate classes will not be granted at this time.

The capital expenditures and planned capital expenditures and the related export contracts have a direct financial bearing on domestic rates and speak to whether MH's projected rate increases through to fiscal 2028/29 are likely to be sufficient to meet the growing capital and other associated costs of the new generation and transmission projects required to service the export contracts.

MH has expended hundreds of millions already on its "preferred development plan", a plan yet to receive regulatory approval on either side of the Canadian-U.S. border. MH continues to spend to "protect" the in-service dates required to meet the obligations of its new export sales contracts.

Regardless of the "good faith" and "good intentions" likely attached to this pre-spending, expending massive funds ahead of final regulatory approval appears to represent speculation, and, given the hundreds of millions that have been spent and the ongoing spending, a degree of speculation rarely found with private utilities, let alone Crown Corporations.

If the plans do not work out, then the pre-spending may well have to be "written off", with implications for rates and the current generation of ratepayers.

These interim findings may be continued or otherwise varied in the Board's next Order.

Operating Results

The Board notes that MH has projected an improved financial position from that it reflected in its IFF 09–1, and accepts that, on the surface of the evidence before the Board, MH has reached its long-sought 75:25 debt to equity ratio. Assuming Board acceptance of the methodology employed by MH to derive its projected debt to equity ratio, a methodology the Board currently continues to question, the Board would have to question the need for any further rate increases other than that required to sustain the capital structure.

The planned major Generation and Transmission projects required to support the announced new export contracts reflect seemingly ever-escalating capital costs, which, pursuant to the filings made by MH, are expected to result in the debt to equity ratio forecast deteriorating from the current asserted 75:25 to 84:16 for fiscal 2020/21.

And that “weakened” projected capital structure is predicated on the Board providing consecutive annual rate increases that compound to reflect an overall increase of over 40% by 2021, and to almost 60% by fiscal 2027/28, required, according to MH’s projections, just to return to the 75:25 ratio now claimed to have been achieved.

All considered, MH’s business case is predicated on stepping up domestic rates by 60% from current levels to support the development of generation and transmission projects, the projects to be advanced for export ahead of domestic requirements, projects yet to receive regulatory approval.

Given the changing circumstances within the North American and MISO market, it is not clear whether the export contracts negotiated can be expected to provide sufficient 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:*

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.

Partnerships and Wind Purchases

The contracts entered into by MH with respect to partnerships with First Nations (the partnership with respect to Wuskwatim Generation Station signed off on and with the generating station well on the way to completion; the partnership with respect to Keeyask Generation Station, being conditional on Keeyask proceeding and that requiring regulatory approvals on both sides of the border) and wind generators are based on factors that go beyond the economic.

There is an "accounting" and "business" aspect to these completed and/or pending arrangements that need to be understood. While MH "treats" the generation and direct payments to the wind farm owners as "purchased power" and intends to amalgamate the power to be generated from Wuskwatim and Keeyask within its consolidated accounts as if Wuskwatim and Keeyask were just another MH hydro-electric generation station, and will record any payments due the First Nations from future partnership net income as deductions from consolidated net income denoted as "minority interest", the accounting fails to identify nuances of some importance.

MH will incur costs that while associated with the First Nations-MH partnerships and the wind farms will neither be charged against the partnerships nor be allocated to its Manitoba wind generation purchases; those costs will simply "fall" to overall operations and so affect domestic rates. These "ignored" costs (ignored only as to recognition in respect to partnership and wind generation costs) include, at least, capital tax (which will be assessed on MH with respect to loan balances attributable to the partnerships and wind farms) and general operating and administration costs that could, fairly, be allocated to the partnerships and the wind purchases.

Power Resource Planning

The Board is not satisfied that MH has explored all reasonable power resource scenarios based on the following assumptions:

- Domestic customers and their rates are the priority;
- Domestic customers and exports share in both fixed and incremental costs; and
- Exports are an independent profit centre, separate from domestic customer classes.

In particular, the Board finds it troubling that MH has not explored in any depth natural gas (CCCT) thermal generation supply alternatives to the new major hydraulic generation and transmission projects now planned for by MH. Yet, MH chose to compare the Keeyask and Conawapa hydraulic generation options to a natural gas (SCCT) thermal generation base case scenario in 2004/05 (a time when natural gas prices were much higher than current prices).

MH's current reluctance or failure to consider CCCT thermal generation as a potentially viable option to its current development plans ignores the presently very competitive position of CCCT generation in the MISO market.

As well, to further "cloud" the present situation, MH's apparent decision to proceed with the Keeyask G.S. to serve the "announced" 125 MW (NSP)/250 MW (MP)/100 MW (WPS) export sales instead of proceeding first with the Conawapa G.S. is a significant departure from both MH's previously devised recommended development plan and, as well, the possible merits of an alternative development sequence.

MH's current plans, backed by expenditures in excess of $400 million on pre-construction Keeyask costs, appear to contemplate a power resource scenario without

Conawapa G.S. if the 400 MW (WPS) contract is not achieved. If this approach was actually taken, it seems the full benefits of Bipole III would not be realized.

With the considerable escalation of project costs for Keeyask G.S., Conawapa G.S. and Bipole III, the Board would prefer MH justify (on a Net Present Value basis) the need for and alternatives to each of these three projects.

Accordingly, the Board strongly believes a thorough 'Needs For and Alternative To' (NFAAT) process, presided over by a quasi judicial panel with independent adjudicative authority and evidence based process should address these issues far in advance of MH making final commitments to enter into its proposed export contracts, and as soon as possible to avoid further massive new investments in MH's preferred development plan ahead of a thorough NFAAT proceeding.

That proceeding should examine not only MH's preferred development plans, but also consider alternative development scenarios including the potential construction of a combined cycle natural gas generation plant, that to diversify supply, reduce drought risk and, potentially defer Keeyask, if not Bipole III.

As to the alternative of proceeding with Conawapa ahead of Keeyask, it also needs a thorough hearing.

Such a proceeding needs to have access to all needed information, including export contracts, and, as well, MH's IFF 20-year forecast needs to be fully updated, to take into account the reality of current and expected market prices in the MISO market.

The Independent Experts suggested to the Board that MH should be focused on 'least cost scenarios' in exploring future power resource and export initiatives. By this recommendation, the Board understands that the Independent Experts, as does the Board, place domestic ratepayers, reliable domestic service, and the rates domestic ratepayers are to pay in future years as the number one priority.

The Board is also concerned about MH's inability to achieve significant (if any) premiums for "clean energy" in its pending export contracts. When MH commits to providing substantially CO_2-free energy without a defined premium, it seems that there is a risk that future environment costs of importing thermally generated electricity could be expected to flow to MH's domestic customers and result in higher domestic rates.

Capital

The Board views with concern MH's infrequent updating of not only its capital cost estimates for major new generation and transmission assets but also its forecasts of spot and opportunity sales export prices. It seems inappropriate to make commitments on major projects and large export contracts when the capital expenditure forecast remains unchanged through three or four years of CEF submissions, and when issued financial forecasts do not reflect changing export market conditions.

There has been a material increase in the capital costs of MH's Major Generation and Transmission Projects, and this has implications, which include increased debt requirements and the related carrying costs (amortization of assets – the cost of which include pre-construction costs - and finance costs on assumed debt) when the projects are placed into service. These projects are being advanced to meet recently entered into export commitments.

Export contract negotiations that appear to use outdated costs of generation and transmission as a point of reference could, in the Board's opinion, seriously undervalue the total energy being sold. Belated capital cost updates will not, it appears, achieve any cost recovery from exports with respect to the additional capital costs.

The Board is unaware of any MH explicit policy or process for ensuring adequate capital investment recovery on facilities built or advanced for export purposes.

Finance Expense/ Financial Risks

Ultimately the total finance expense associated with MH's planned new major capital construction of generation and transmission will need to be recovered from future revenue as the major projects come on line and capitalization of interest ceases.

As it is, a significant percentage of MH's annual finance expense is currently being capitalized, and MH has forecast that over $5 billion will have been capitalized when all developments are complete. The Board remains concerned with the significant escalations in the capital cost for these major projects, which appear to be resulting in seemingly ever increasing borrowing requirements. Such capitalized amounts will form part of the capital base and will be need to be recovered from future revenue.

Once the major projects have been completed, the capitalization of finance expense will cease and will need to be recovered from revenue. If net export revenues are insufficient to meet all of the period costs that will begin to be recorded in MH's accounts following the in-service dates of the new assets, then domestic rate payers will be required to subsidize the investments through rates (if the debt to equity ratio target is to be maintained).

As the cost of the major programs escalate there will be, as demonstrated in the recent increase of over $3.6 billion from prior IFF 09-based estimates, both increased debt levels and ultimately higher finance costs (which may well have to be recovered solely from domestic ratepayers as the export sales prices were developed prior to the construction cost escalation).

There remains a real risk that interest rates may rise from what has been forecast by MH. Given the increases in Long Term Debt from the ever escalating cost of the Major Generation and Transmission projects, such a higher interest rate environment with the increased borrowing requirements, will further erode MH's financial strength to the detriment of domestic ratepayers. To the extent that export revenues do not materialize, interest costs do not disappear and will have to be met by domestic ratepayers.

As for foreign exchange rate risk, the Board notes that the Canadian dollar is currently above par with its USD counterpart, yet MH continues to project a weakening Canadian dollar relative to USD within MH's forecast period. In the Board's view, there is a real risk that the current exchange paradigm (with the Canadian dollar at or above par with its US dollar counterpart) may be sustained for a long period of time.

While the Board is not certain on how such an eventuality would impact MH's financial position, it is concerned that MH's current forecast of future export revenues may be overstated. As MH has experienced in the past couple years, a Canadian dollar at or above parity with its USD counterpart has resulted in lower realized export revenues.

MH's preferred Development Plan is predicated on export revenues derived from the new export contracts with US counterparties to support the costs incurred to build the Major Generation and Transmission Assets required to service them. A weakening USD would place further pressure on MH, which may then have to seek to recover any shortfall from domestic ratepayers.

The Board will require MH to provide a full analysis of the implications of a Canadian dollar at or above parity on its long-term Preferred Development Plan.

Domestic Load Forecast

With MH's forecast of domestic load being down by 1,400 to 1,800 GWh, the unit revenue (rate per kWh) would have to increase to retain MH's forecast of future annual electricity revenue. However, MH has not made any significant adjustment to its projection of domestic rates and MH's forecast of total residential and commercial load was identical in IFF 10 and IFF 09-1. MH has yet to explain how this is possible.

The Board is unable to reconcile MH's domestic load forecasts with domestic revenues and is concerned that MH's forecast domestic revenues may be overstated.

In MH's Recommended Development Plan, (IFF 09-1 assumptions) Keeyask G.S. had an in-service date of 2019/20; in the Board's view domestic load, only, would have required a 2021/22 in-service date, and now with the reduced domestic load forecasts a 2025/26 in-service date could be more appropriate.

It is the Board's view that MH's most recent domestic load forecasts for the longer term:

- Do not adequately recognize the longer term implications of the recent economic downturn;
- Are overly optimistic, given the stagnation (lack of growth) over the last five years in the load of the industrial sector - particularly when coupled with an actual major pulp and paper plant closure and imminent announced smelter and refinery closures; and

- Do not support the significantly advanced dates for new generation, but rather, in the absence the new export contracts, suggest a 2025/26 in-service date is required to meet domestic load.

The Board understands that the recent MP and WPS announced contracts essentially commit MH to building Keeyask G.S. by 2020/21. This is about five years earlier than domestic load requires.

Export Contracts

Without access to MH's new export contracts, the Board continues to see these ventures as potentially unfavourable risk issues. There is no certainty that the revenue streams from those announced contracts will cover the incremental revenue requirements of new generation and transmission.

The Board does not see that the volumetric drought risks are being reduced with the new export contracts. Cost consequences of a drought may well be greater with the contracts in place. As of now, the question is open for debate, as there are experts that say the consequences of a drought with the new export contracts should be lower.

However, these experts have all seen the export contracts and are, presumably, relying on MH's, and perhaps their own, interpretation of the Adverse Water clauses. Because the Board has not seen the contract to verify the salient terms, the Board advises that it may change its view after it receives and has reviewed the contracts.

Export Revenue Pricing

It is the Board's understanding that MH's IFF 09-1 forecast (particularly for electricity export revenues) was based on 2008 circumstances, and, presumably, employed ICF predicted natural gas prices. The forecast predated the advent of shale gas and lower natural gas prices, the collapse of CO_2 emissions charges and the severe economic downturn that has transpired in the U.S. economy.

With ICF's revised (October 20, 2010) natural gas prices being 30-40% lower than its 2008 forecast, projected electricity prices with respect to the fuel cost portion of CCCT generation may well be lower by a comparable amount. (If fixed costs were included in the IFF assumptions, the forecast electricity price would be about 25% lower, rather than 30-40% as projected by ICF).

While MH has declined to provide an IFF using the export electricity pricing assumptions advanced by the Board (PUB/MH/PREASK-4), MH has not refuted the proposed pricing scenario, which, at about 65% of IFF 09-1 pricing assumptions, are in the Board's view relatively consistent with ICF's revised natural price forecast when applied to CCCT generation fixed and variable prices.

In the absence of any significant MH downward revisions of export market electricity prices to reflect the drastic shift in the forecast cost of CCCT thermal generation, the Board has elected to address this issue by postulating two alternative electricity export pricing scenarios. These are not the only, or necessarily correct, views of MH's export market over the next 15 years.

And, at 75% and 65% of MH's IFF net export revenues assumptions, the Board's price forecast could be viewed as somewhat pessimistic if not very pessimistic as to a recovery of past and higher MISO Market electricity prices.

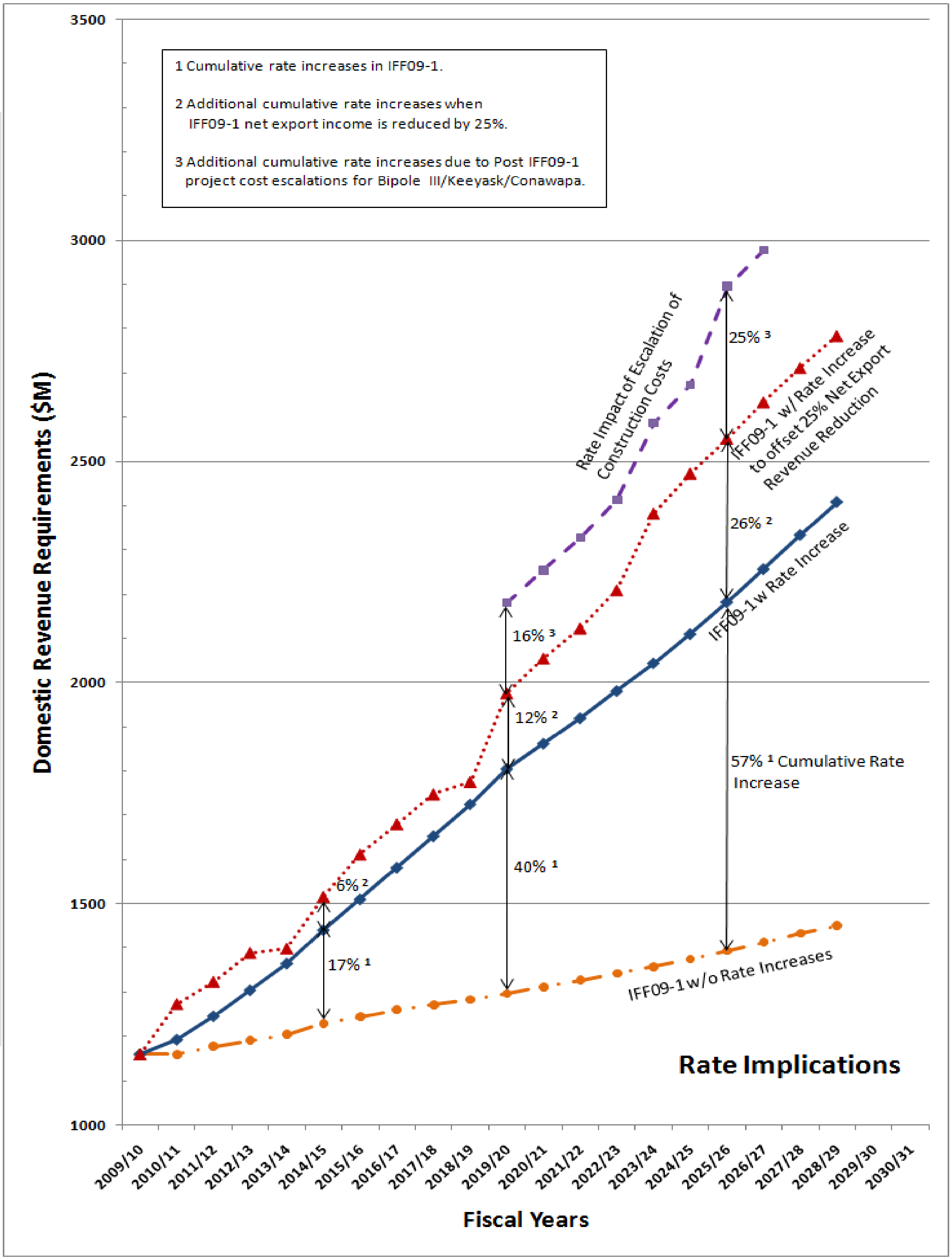
In Chart 2, which follows below, the lower line (red-dashed) projects MH's domestic revenue in the absence of any domestic rate increases over the next 20 years. The next line up (blue-solid) illustrates MH's IFF 09-1 based domestic revenues with MH's projected rate increases (2.9% to 3.5%/year, annually). In 2025/26, such an eventuality would be expected to result in overall domestic revenue of about $2.2 billion (57% of which would arise from rate increases).

If, as a result of ICF's projected lower natural gas price forecasts, MH's export revenue projections of IFF 09-01 were reduced by 25%, this would negatively affect IFF 09-1 projections for net income, retained earnings and MH's debt:equity ratio. Accordingly to meet MH's targets of its IFF 09-01, domestic revenue would have to be increased as shown in the 3rd line from the bottom (red–dotted). In 2025/26, such a scenario suggests that domestic revenue of about $2.25 billion would be required (which would represent another 26% increase from the 57% projected by MH in IFF 09-1).

This upper line (blue-dashed) models the required addition of domestic revenue that appears to arise from the major project price escalation that has developed since MH's IFF 09-1 forecast. In 2025/26, recognition of this factor suggests that the domestic revenue requirement would be approximately $2.85 billion (up a further 25% from that projected by MH).

Chart 2

Domestic Revenue Requirements and Rate Implications (75% of IFF 09 Export Revenue Rates)



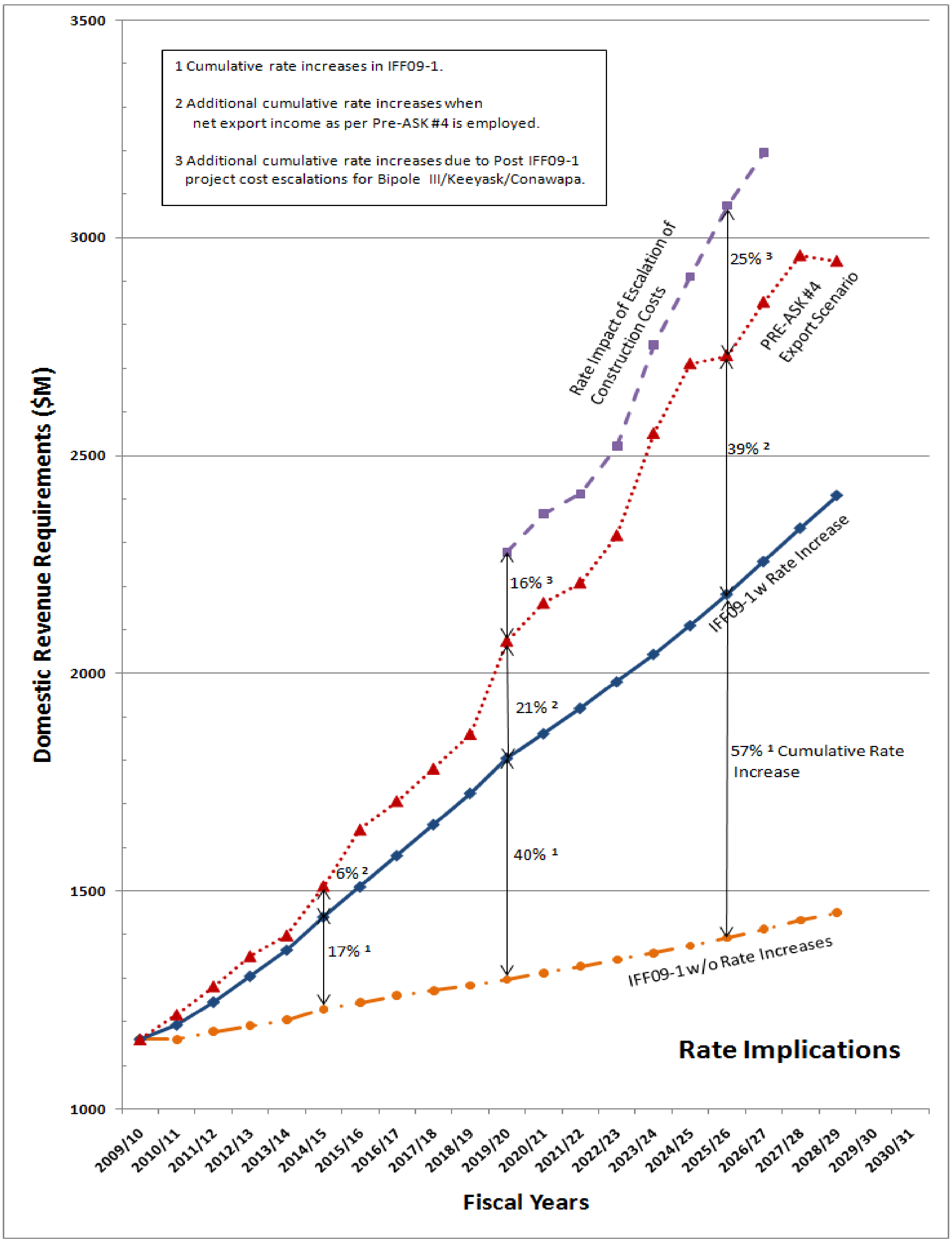
In Chart 3, which follows, the lower line (red-dashed) projects MH's domestic revenue in the absence of any rate increase over the next 20 years. The next line up (blue-solid) illustrates MH's IFF 09-1 projected domestic revenues with MH's projected rate increases (2.9% to 3.5%/year). In 2025/26, MH's assumptions project domestic revenue of about $2.2 billion (57% of which would come from rate increases).

The third line (red-dotted) on the chart illustrates the domestic revenue requirement if export revenues were consistent with the export/import price scenarios PUB requested MH provide in PUB/MH-Pre-ask #4, and if MH's IFF 09-1 targets for net income, retained earnings and debt-equity were to remain unchanged. In 2025/26, this assumption requires domestic revenue of $2.7 billion (up another 39% increase from the 57% projected by MH in its IFF 09-1).

The upper line (blue-dashed) indicates the additional domestic revenue requirement that would presumably result from meeting the major project cost escalation that has occurred since IFF 09-1 was developed by MH. In 2025/26, recognizing this development would require domestic revenue of about $3.1 billion (up a further 25% from the 57% modelled by MH's IFF 09-1 and the 39% projected by the presumed response to PUB/MH-Pre-ask #4).

Chart 3

Domestic Revenue Requirements and Rate Implications (PUB/MH Pre-Ask #4 Export Revenue Rates)



These charts suggest that MH's IFF 09-1's rate increase assumptions may prove significantly too low if ICF's lower natural gas prices "prevail" and MH's latest capital estimates are realistic. It is possible that actual domestic rates could be more than doubled over the next two decades if the Board's modelled assumptions were realized.

In the Board's view, MH's IFF 09-1 and IFF 10-2 export price assumptions are not reflective of the current and likely near-term energy market. As such, the suggested progression of rate increases for domestic customers may well not be adequate to cover, even after taking into account projected additional export revenues, the costs of MH's CEF 09 Major Capital Expenditure Program. And, when the latest major project cost escalation is considered, the potential revenue insufficiency appears to be substantially magnified.

Export Revenue Pricing

In Board Order 116/08, it was the Board's opinion that MH's export revenue pricing forecasts provided in the preceding 2008 GRA, and in MH's 2008 Energy Intensive Industry Rate (EIIR) application, were overly optimistic. Prior to 2008/09, MH's forecasts counted on future high natural gas supply prices (forecast to continue to rise and anticipated an early introduction of substantial CO_2 emissions pricing. These are no longer realistic expectations.

IFF 09-1 export revenue pricing (based on advice to MH from an external consultant panel, which, as previously indicated, included ICF) was prepared in 2008 and neither reflected the lower natural gas prices with shale gas availability now being experienced nor the evident major resistance to CO_2 emissions pricing in the U.S.

ICF testimony at this hearing provided a much lower future natural gas price outlook and suggested that a substantial deferral of CO_2 emission pricing would take place. Despite this, MH did not significantly alter its IFF 10 Export Revenue Assumptions from those MH employed in IFF 09-1. Notably both ICF and KPMG indicated that, pursuant to their terms of reference, which were provided by MH, they did not challenge MH's views on market energy prices. Apparently, neither ICF nor KPMG nor the Independent Experts had access to MH's IFF market price derivations.

The Board also notes that MH declined to provide any alternative IFF scenarios based on the now obviously lower natural gas prices and absence of CO_2 emissions regulations.

Overall, the Board does not accept MH's export revenue forecasts to-date as representing a realistic basis for determining the economic viability of MH's proposed new major generation and transmission facilities, to be supported by export sales in advance of domestic load requirements.

Implications for the Domestic Revenue Requirement

Based on the evidence in this proceeding, the Board suggests that the cumulated rate increase required of domestic customers would, by fiscal 2025/26, be significantly greater than the approximately 60% (57%) forecast in IFF 09-1, and, more probably, the cumulated rate increase in 2025/26 could be in the 100% to 120% range (roughly double MH's forecast).

In the next MH rate application, the Board will require MH to file a revised 20-year electric IFF, reflecting as of December 31, 2012:

- Updates to construction costs;

- Projected extra-provincial gross and net revenues;
- Projected domestic and export loads;
- Projected net income;
- Debt equity ratios;
- Projected retained earnings; and
- Projected future domestic rate increases (2012/13 to 2032/32).

Further to the above, the Board will also require MH to analyze and file the implications associated with limiting annual domestic rate increases to 2%, using a 7% discount rate net present value analysis of MH's Development Plan.

This should indicate the adjusted:

- Projected net income;
- Debt/equity ratios; and
- Projected retained earnings.

Drought

Without going into a detailed litany of the various critiques of MH's drought risk processes issued by various parties since 2003/04, the Board is convinced that there are many areas of MH's Drought Risk Management processes that could be improved upon.

These include a more open and transparent management of volumetric risks and price risks. As well, annual post-mortems (back-testing of decisions) should be normal practice. (The Board, in its 2004 GRA Order directed MH to provide such a post-mortem of its actions through the drought of 2003/04, that report was never filed.)

In the Board's view, and in the Board's present predicament of not being privy to MH's export contracts, MH's export business model does not appear to be the assured profit generator that it may have been in past decades. Specific concerns relate to what appears to be MH's misconception that export sales are always profitable when they exceed water rentals and transmission losses; subsequent repurchase costs and the need for export contributions to embedded costs seem to be ignored.

The Board cannot be sure that MH's drought management actions in the period 2002/03 to and including 2004/05 were optimal, when a $436 million net loss required a rate increase aggregating 9.5% to restore MH to its financial targets. That result cannot, in the absence of detailed post-mortem review, be considered ideal. MH should be looking to do better in the future than it did in 2003/04.

In a response to an interrogatory submitted by the Board, MH responded that it would file a written Drought Preparedness Plan by April 1, 2011; MH did not. In cross-examination, MH suggested that a written plan was not needed as MH reacts "everyday" on the basis that a drought could be starting, and it would be difficult to reduce all of MH's experiences into a written plan, when MH has to plan given an infinite number of variables. However, another MH executive appear to over-rule the other executive by indicating "…(it) would be a good idea to have a written drought preparedness plan… "

MH was disingenuous in its response to the Board's interrogatory and it remains to be seen if the Corporation will follow through on its written evidence and oral testimony by a Vice-President.

The Board recommends MH act to meet the urgent need for such a document.

There appears to have been a prodigious amount of study and analysis since 2003/04 (KMG, ICF, Independent Experts, 2008 and 2010 GRA) on MH's risk practices and management. Further work is still warranted. The severe consequences that can attend a drought or less than optimal decisions on major capital projects and export contracts require the attention now apparently being given to the risks.

Power Resource Modelling

The Board accepts that there have been valuable insights gained from the rather extensive number of experts involved on the broader risk issues since the 2003/04 drought event. Significant contributions were made by the following:

- Risk Advisory (engaged by MH);
- Manitoba Water Stewardship Expert Panel (Wuskwatim Hearings);
- NYC (initially engaged by MH);
- Dr. Bhattacharyya (engaged by MH);
- ICF and KPMG (engaged by MH); and
- Independent Experts (engaged by the Board).

The Board has been given to understand that MH has and will be acting on many of the recommendations made in these various reports. The Board sees a need to verify the status of those changes and to seek assurance as to further improvements to MH's modeling process.

Despite an extensive and protracted process that involved numerous experts, there is still no clear indication of the appropriate level of retained earnings required as a drought reserve. While MH does not formally target a specific level of retained earnings, or provide for a specific drought reserve, achieving and maintaining a debt-equity ratio of

75:25, debt to equity, is viewed by MH as the best way to financially position itself for a severe drought, such as has been experienced within the historical record.

The Board has heard recommendations and commentary about:

- Dedicated drought reserve;
- Greater energy-in-storage;
- Export contract value-at-risk reserves; and
- Domestic rate-riders to track export price volatility.

In the Board's view, none of these absolutely preclude the diversion to other purposes of reserves intended for drought recovery. However, the Board favours measures that may reduce the volumetric domestic and export load shortfalls and thus limit the cost impact of drought events. Such measures could include:

- More clearly defined curtailment opportunities within the long term export contracts;
- Stricter volume limits on summer bilateral agreements;
- Redefinition of dependable energy to reduce the non-hydraulic generation components that go to defining dependable surplus energy;
- Adding CCCT thermal generation units to MH's power sources to beef-up dependable generation (generation diversification, as practised by most North American electricity utilities);
- A minimum energy-in-storage policy, in effect a water reserve that cannot be tapped into except in below average flow years;
- Hydrologic predictions of potential spring runoff and potential summer evaporation losses; and

- Disclosure of annual back-testing of supply system operations and net export revenues achieved.

The Board is aware that ICF/KPMG/Independent Experts reports alluded to the ability to gain domestic rate increases (if approved by the Board) as a risk mitigation factor. This is not inconsistent with what happened after both 2003/04 drought and the 2006/07 mini-drought, where rate increases were provided to MH; increases that have provided ongoing revenues that, as a present value, has provided well in excess of the specific revenue shortfalls experienced. Ratepayers have not seen any subsequent rate relief.

Concluding Note

On a positive note, and recognizing that the in-depth risk assessment explored in this hearing (limited by MH's refusal to provide its export contracts, fully updated 20-year financial forecasts and alternative development scenarios, as requested by the Board) was partially stimulated by the dire predictions of bankruptcy and blackouts by NYC, the Board is satisfied by the unanimous evidence of all the experts heard from that such dire predictions are without merit.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure (Rules). The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

6.0 IT IS THEREFORE ORDERED THAT:

1. Manitoba Hydro's requests to finalize existing interim rates and for an additional 0.9% rate increase for all customer classes, effective August 1, 2011, BE AND IS HEREBY DENIED;

2. Existing interim rates and MH's request for a further 0.9% rate increase will be further considered and may be adjusted on a final basis in a subsequent Order of the Board;

3. This Order shall remain interim until a further Order of the Board.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE CA"
Chairman

"HOLLIS SINGH"
Secretary

Certified a true copy of Order No. 99/11 issued by The Public Utilities Board

Secretary

Appendix A

Appearances

R. Peters A. Southall	Counsel for The Manitoba Public Utilities Board (Board)
M. Boyd P. Ramage	Counsel for the Manitoba Hydro Electric Board (Hydro)
B. Williams M Bowman	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc./ Winnipeg Harvest (COALITION)
A. Hacault	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson (np)	Representing *Manitoba Keewatinook Ininew Okimowin*. (MKO)
W. Gange D. Rempel P. Miller	Counsel for Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Pambrum	Counsel for the City of Winnipeg (CITY)
D. Coad (np)	Southern Chiefs Organization (SCO)
G. Wood	Independent Experts

(np)- not present at the hearing

Appendix B

Witnesses for Hydro

V. A. Warden	Vice-President, Finance & Administration and Chief Financial Officer
H. M. Surminski	Section Head, Generation System Studies, Resource Planning and Market Analysis
K. R. Wiens	Division Manager, Rates & Regulatory Affairs
D. Cormie	Division Manager, Power Sale
L. J. Kuczek	Division Manager, Consumer Marketing and Sales
D. Rainkie	Corporate Controller, Corporate Controller Division
M. Schulz	Corporate Treasurer

KPMG Panel

W. Lipson	Partner
F. Chen	Director, Financial Risk Management
J. Erling	Managing Director, Toronto
A. Gupta	Senior Manager

ICF International Panel

J. Rose	Managing Director

Appendix C

Interveners of Record

Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors/Winnipeg Harvest (Coalition)

Manitoba Industrial Power Users Group (MIPUG)

Manitoba Keewatinook Ininew Okimowin (MKO)

Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)

City of Winnipeg (CITY)

Southern Chiefs Organization (SCO)

Independent Experts Panel

Dr. Atif Kubursi	Professor Emeritus, Department of Economics McMaster University
Dr. Lonnie Magee	Professor, Department of Economics, McMaster University

Appendix D

Intervener Witnesses

CAC/MSOS

W. Harper	Manager, Econalysis Consulting Services, Inc.
R. Colton	Fisher, Sheehan & Colton
G. Matwichuk	Stephen Johnson Chartered Accountants
J. McCormick	McCormick Financial Services Inc.
T. Carter	Professor, University of Winnipeg

MIPUG

A. McLaren	Consultants, InterGroup Consultants Ltd.
P. Bowman	

RCM/TREE

P. Chernick	President, Resource Insight Inc
J. Wallach	Vice-President, Resource Insight Inc.

Appendix E

Presenters

Mr. A. Ciekiewicz	Citizen
Mr. B. Turner	Chair, Manitoba Industrial Power Users Group
Mr. R. Rader (written only)	Managing Director, Koch Fertilizer Canada, Ltd.
Mr. John Gray	Citizen
Mr. Lynn Jones (written only)	Citizen
Mr. Norm Gruhn (written only)	Citizen
Mr. Mark Shirley (written only)	COO, Amsted Rail
Mr. Art Carriere (written only)	Citizen
Mr. Graham Starmer	Manitoba Chambers of Commerce