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

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

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

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1.0.0 EXECUTIVE SUMMARY

In this Order, the Public Utilities Board (Board or PUB) finalizes Manitoba Hydro's (MH or the Corporation or the Utility) April 1, 2010 average consumer rate increase at 1.9% and also finalizes MH's April 1, 2011 average consumer rate increase at 2.0%.

MH requested finalization of a 2.9% average consumer rate increase effective April 1, 2010 and a further 2.9% rate increase effective April 1, 2011. Since those two dates, MH has been charging Board-approved interim rates of 2.9% and 2.0% respectively.

This final Order should be read in conjunction with Order 99/11 – which, along with all Board Orders, is available through the Board's office or by viewing its website www.pub.gov.mb.ca.

As indicated by the Board in Order 99/11, MH failed to discharge its statutory and legal onus in its substantiation of its requested rate increases. The Board therefore finalizes the rate increases at a level less than applied for by MH.

Based on the evidence before the Board, for MH's fiscal 2010/11 and 2011/12 years, the finalized rate increases in this Order, which are aligned to MH's forecast rates of inflation, yield just and reasonable rates that are in the public interest. MH also put before the Board its plans for the ten-year period to 2020, a period which is described by MH as its 'decade of investment', during which MH's major capital investments – namely new generating stations and transmissions line – are forecast to total approximately $20 billion. MH's 'Business Model' includes building new generating stations in the expectation of being able to export the energy generated by these stations prior to the output being gradually required by Manitoba consumers.

The Board finds MH's business model to parallel MH's development of the Limestone Generating Station. History records Limestone G.S. as producing electricity at a cost of approximately 3¢ kWh but selling it for 1.5 - 2¢ kWh on the export market. MH lost money during the early years of Limestone's generation.

Based on MH's most recent estimates of the capital costs to construct Wuskwatim G.S. (scheduled to come into service in 2012), Keeyask G.S., and Conawapa G.S., the unit cost of electricity when these generating stations will be in service approximates 10¢ kWh. There will also be additional annual costs of approximately $150 Million per year for Wuskwatim, $500 Million per year for Keeyask and $700 Million per year for Conawapa. All of these fixed costs, along with operating expenses, will appear on MH's Operating Statement and will have to be recovered from export revenues and domestic customers. If the revenue generated is insufficient to recover the costs, higher consumer rates would be expected.

While MH has yet to file the detailed pending export agreements (the Board's request is being contested by MH in the Courts), from the record it is apparent that the export prices will not recover 100% of the costs incurred by MH to export that electricity. Therefore, it would fall to Manitoba's domestic ratepayers to subsidize the export sales commitments made by MH.

Even though MH forecasts domestic rate increases in the 'decade of investment' that are in excess of expected inflation, it appears the projected rate increases are considerably too low to support the required subsidization.

The Board is unable to approve the higher rate increases requested by MH because the Utility's business plan is incomplete, lacks required detail and has not been tested through what has been promised as a "Needs For And Alternatives To" (NFAAT) review by an independent tribunal that will have full access to the economic and financial assumptions which underpin MH's business plan.

Such a broad-scope NFAAT was last held in conjunction with MH's plans to construct Conawapa G.S. as a merchant plant. At the time, the plan was to sell the output from the plant to Ontario Hydro. Under the applicable business plan, approved by the Board in the early 1990s, MH's forecast costs to build and operate Conawapa were lower than the forecast payments expected to be received from Ontario Hydro. There was no expectation of subsidization by domestic ratepayers. Rather, there was an expectation of a net benefit to MH and its ratepayers over the entire term of the export contract with Ontario Hydro. That plan was not actualized as Ontario Hydro withdrew, leading to a negotiated settlement (Ontario Hydro compensated MH for the vast majority of its actualized development).

In addition to providing a detailed review of the economic and financial assumptions of MH's preferred development plan, an NFAAT for MH's proposed investment would also test a number of viable alternative development plans, which is necessary to ensure that electricity rates for Manitobans remain just and reasonable and in the public interest.

The Chairman and Vice Chair differ in their opinion as to whether such an NFAAT should include the planned Bipole III transmission line. The Chairman hopes that any alternative plans to be reviewed would include the use of natural gas-generated electricity to improve on reliability issues and avoid or at least delay the requirement for a Bipole III Transmission Line (Bipole III). The Vice Chair does not share this view. In the Vice Chair's view, Bipole III is required for reliability purposes in any case and its construction should not be delayed any more than necessary. This difference in opinion does not affect the Board's Directives.

The Chairman and Vice Chair agree that the seemingly ever increasing forecast in-service costs of Bipole III are likely to add approximately 3¢/kWh to every kWh transmitted from Northern Manitoba. MH seeks to assign 100% of the currently forecast (by MH) $3.2 Billion cost of Bipole III to Manitoba's domestic customers despite the fact that Bipole III will be used to meet export demand if new generation capacity is built.

It greatly concerns the Board that without having had its capital plans reviewed through an NFAAT proceeding, and without the US transmission lines required to transmit MH's electricity exports south of the border having been constructed or even been committed to, and without MH having obtained the required regulatory approvals in Canada, MH continues to spend $1-$2 Million per day on its currently favoured development plan.

A significant aspect of the scope of MH's General Rate Application was the review of MH's risks and risk management. The Board has long requested MH to provide an in-depth and independent study of MH's risks (see Order 32/09). The study was to be a thorough and quantified risk analysis that included probabilities of all identified operational and business risks. Unfortunately, and disappointingly, MH failed to provide a comprehensive quantified risk analysis. Instead, MH unilaterally changed the terms of reference to instruct an external consultant to prepare a report, and opted for a legal strategy to try and rebut the findings of a former risk consultant previously retained by MH but subsequently terminated. However, even without the expected comprehensive risk analysis, the Board was able to gain a better understanding of the Utility's risk. For this risk, MH presently reports $2.4 Billion of retained earnings.

This Order also approves and finalizes MH's Surplus Energy Program Rate Orders and Curtailable Rate Program Orders. Due to insufficient information provided by MH, the Board has denied MH's request to 'forgive' what were approved as temporary demand billing concessions to a limited number of commercial and industrial customers.

This Order also provides the Board's comments and findings with respect to other aspects of MH's GRA, as further set out below.

The Board was ably assisted in its extensive review by interveners and their witnesses.

2.0.0 PROCEDURAL HISTORY, INTERVENERS, AND PRESENTERS

2.1.0 PROCEDURAL HISTORY

When MH filed its 2010/11 and 2011/12 GRA with the PUB, its main request was Board approval of an average consumer rate increase of 2.9% effective April 1, 2010 together with a further 2.9% average consumer rate increase of 2.9% effective April 1, 2011.

In light of a lengthy prehearing scoping and discovery process, together with a lengthy oral evidentiary hearing, the Board initially addressed MH's rate increase request on an interim, but not final, basis.

In Order 18/10, the Board approved an average 2.9% interim rate increase to all customer classes (except Area and Roadway Lighting) effective April 1, 2010. In Order 40/11, the Board approved an average 2.0% rate increase to all customer classes (except Area and Roadway Lighting) effective April 1, 2011.

The Board's stated intention was to re-examine the interim rate increases prior to finalization after hearing all of the evidence and submissions in the GRA and, if the Board concluded that the underlying facts did not justify the imposition of rate increases as sought by MH – or as approved by the Board on an interim basis – the Board would adjust the rates in the final GRA Order. Any amounts collected through interim rates that were found to be in excess of the rate in the final order would then be refunded or credited back to domestic customers.

Following the oral evidentiary portion of the GRA and the closing submissions, the latter of which extended over three days (July 4, 5, and 7, 2011), the Board issued Order 99/11 on July 29, 2011, which was envisioned to be the first of two Board Orders to be issued arising out of MH's 2010/11 and 2011/12 GRA. This Order is the second of the two Board Orders issued in respect of MH's 2010/11 and 2011/12 GRA and should be read as a companion Order to and in conjunction with Order 99/11, as well as Orders 18/10, 30/10 and 40/11.

All Board Orders can be found on the Board's website www.pub.gov.mb.ca or by contacting the Board's office.

2.2.0 INTERVENERS

2.2.1 Overview

The Board received requests for intervener status from the Consumer's Association of Canada (Manitoba) Inc./Manitoba Society of Seniors (CAC/MSOS), the Manitoba Industrial Power Users Group (MIPUG), Resource Conservation Manitoba/Time To Respect Earth's Ecosystems (RCM/TREE), the City of Winnipeg, the Manitoba Keewatinowi Okimakanak (MKO), the Southern Chiefs Association (SCO), the New York Consultant (NYC), whose name Board decided not to publicize, and from Mr. Ciekiewicz.

By way of Board Order 17/10, the Board granted intervener status to CAC/MSOS, MKO, MIPUG, the City of Winnipeg, and RCM/TREE, and denied intervener status to Mr. Ciekiewicz.

By way of Board Order 30/10, the Board granted intervener status to SCO and denied intervener status to NYC.

The submissions of CAC/MSOS, MIPUG, RCM/TREE and the City of Winnipeg are set out in the respective "Intervener Positions" sections of this order.

The submissions of MKO and SCO were very limited in scope and are set out below.

2.2.2 MKO

While MKO has been a regular Intervener in MH's proceedings before the Board, MKO chose not to actively participate during MH's 2010/11 and 2012 GRA despite having been granted Intervener status.

2.2.3 SCO

SCO represents the interests of 32 Southern Manitoba First Nations and was granted Intervener status in this hearing.

SCO questioned the openness and transparency of MH's responses to information requests regarding environmental impacts associated with MH's operations.

SCO submits that the Board must not dismiss or negate claims of cumulative impacts and adverse effects on Southern Manitoba First Nation, due to MH's ongoing operations of its Integrated Power System.

SCO stated that Lake Winnipeg, Cedar Lake, South Indian Lake and other secondary sources such as Lake Manitoba, Lake Winnipegosis and Lake of the Woods are considered by MH as "energy in storage" (EIS). These EIS sites are used to calculate and regulate the main reservoirs, which in turn generate revenue for MH at the expense of SCO's First Nations' Aboriginal and Treaty rights and interests.

SCO submits that if the Board increases the rates, any increases should be set aside in a deferral account, to be used for the benefit of all Manitoba First Nations to offset any compensation required to be paid as a result of negligent operations of MH's projects and facilities.

2.3.0 PRESENTERS

The Board also heard from several presenters. Presenters did not have the right to participate in the hearing or cross-examine witnesses, but were given the opportunity to make brief submissions to the board. The submissions of the Presenters are summarized below.

2.3.1 Dr. Leonard Simpson and Mr. Blair Skinner

Dr. Simpson and Mr. Skinner presented information to the Board respecting potential development of a nuclear power generating station at the former Atomic Energy Canada Limited nuclear research site located near Pinawa, Manitoba.

Dr. Simpson stated that MH has set forth very ambitious and expensive plans for future development which are focused on our northern rivers and involve the expenditures of billions of dollars.

Dr. Simpson suggested that MH be directed to undertake a feasibility study of the potential development of a nuclear facility to determine whether it would be economic to have a major source of power close to the market. According to these Presenters, MH has not shown interest in building an infrastructure of nuclear expertise, however MH has indicated a willingness to buy and market the power if it is produced by a private vendor who would build and operate the station.

Dr. Simpson stated that the Whiteshell facility has been under nuclear license for 45 years, and because of that license, the development of a nuclear generating station on the site would require a shorter development time frame than other sites. Dr. Simpson compared the economic and employment benefits of a nuclear facility, which would result in long-term high-quality employment compared to a northern generating station which would have significant employment while being built, but with limited sustained employment once completed.

Dr. Simpson stated that the Pinawa location would be well-suited for the CANDU 6E nuclear generator which has been demonstrated in Korea, China and Argentina. A nuclear facility at the Pinawa site would have access to cooling water from the Winnipeg

River system, would be 100 km from the new converter station, close to an existing transmission corridor and could produce 700 MW of electricity.

Dr. Simpson stated a delay in Bipole III would save $4 billion and would cover more than half the capital cost of nuclear plant with the creation of 500 well-paid jobs to operate the plant with increased tax revenue and restored prosperity to the region.

MH's generation is 96 percent hydraulic, and thus susceptible to drought. According to these Presenters, the inclusion of nuclear power in MH's supply portfolio would create a more diverse generating system which would translate into greater system reliability.

2.3.2 Manitoba Chamber of Commerce – Mr. Starmer

Mr. Starmer appeared on behalf of the Manitoba Chamber of Commerce (MCC). MCC has long been a leading advocate of assisting citizens in need. It has proposed numerous changes to government to improve the lot of less fortunate citizens and is active in the poverty community, working in such areas as housing, food supply, and disabilities.

The MCC opposes the PUB being placed in a position of having to implement social policy through the setting of MH rates. The MCC is not taking a position related to whether a rate increase is justified, but if support for low-income users is included, which would impact upon the cost of electricity to other users, then MCC would oppose such an initiative.

The MCC believes that making Manitoba a better place to work and live is best achieved by keeping a number of principles in mind. Three principles advocated by MCC are:

- Representatives are elected by voters to manage the government and develop public policy.

- The basic responsibility of government is to assist those in society who are in need through social programs;

- A fundamentally accepted principle is that those in need be assisted by those who have the capacity to do so. This is the basic reason for progressive tax rates where government taxes those with the capacity to pay and give to those in need.

MCC submitted that as a public utility, MH should not be involved in social programs, nor does it have the expertise or mandate to institute public policy programs.

2.3.3 Gerdau Ameristeel – Mr. Forsyth

Mr. Forsyth appeared on behalf of Gerdau Ameristeel (Gerdau). Mr. Forsyth stated that Gerdau's steel mill in Selkirk is one of the largest manufacturers in the Province and is one of the largest shippers in the region, averaging over 150 truck loads and 25 rail cars per week. Mr. Forsyth noted the significant economic contribution Gerdau makes to the Province, which includes 770 direct jobs, spending more than $49 million with local suppliers and service companies, and generating indirect employment.

Gerdau is the largest recycler in the province, processing scrap metal collected from throughout the region, recycling approximately 400,000 tonnes of scrap each year. Mr. Forsyth stated that the processes followed by Gerdau are environmentally responsible, noting that making steel from scrap metal reduces energy use by 70% and emissions by 60% when compared to steel made from iron ore by a steel mill. The manufacturing process is energy- and capital-intensive, with electricity costs being second only to scrap steel costs as an input cost.

Energy efficiency is one of the tools that assisted Gerdau’s Manitoba facility in improving its competitiveness. Low-cost, stable, and reliable electricity is essential to Gerdau's operations in Manitoba. While energy costs in Manitoba are generally favorable, other input costs such as labor and transportation and fuel costs have countered some of the advantage offered by lower-cost electricity.

Mr. Forsyth stated that energy rates have increased substantially since 2004, increasing by over 20% since that time. With respect to the 2.9% rate increase request for 2011 and 2012, Mr. Forsyth noted that the PUB had provided interim approvals for the 2.9% increase for 2010 and the increase of 2.0% for 2011 fiscal year. Gerdau requested the Board to reconsider the contemplated increase and modify it to reflect the cost of service to the industrial customer class. Gerdau submitted that during these difficult economic times, costs must to be reduced, not increased, as they cannot be passed along to customers.

During the depths of the economic downturn in 2009, the Gerdau Manitoba facility saw production orders fall dramatically. Notwithstanding the significant economic downturn, Gerdau undertook initiatives to maintain employment by using a work share program and initiated new plans to operate the plant as efficiently as possible at the reduced operating rate. One component of costs that stood out immediately was the average price of electricity. With the reduced load at the plant, the average unit cost of electricity skyrocketed overnight by over 40% and became a major issue for continued operation. Gerdau entered into discussions with MH to rectify this unintended consequence. With the demand billing concessions provided by MH, Gerdau avoided making some relatively hard decisions with respect to the continued operation of the plant.

Mr. Forsyth recommended that the demand billing concession granted to Gerdau should be made permanent, consistent with MH's Application. He noted that the demand billing concession reacted as expected to the needs of energy consumers impacted by the economic downturn. The affected customers were able to keep people employed while ensuring that MH's revenue stream was secure.

2.3.4 The Bipole III Coalition – Mr. Derry

Mr. Derry, a retired professional engineer who spent 20 years with MH, presented on behalf of the Bipole III Coalition, which advocates for routing the transmission line down the east side of Lake Winnipeg rather than the west side.

Mr. Derry stated the east side route is preferable because of greater economic, social, technical and environmental benefits for all Manitobans. According to the Bipole III Coalition, the western route will cost at least $1 billion more for ratepayers than the more direct eastern route. The longer line will cause line losses equivalent to all wind energy generated annually in Manitoba and equivalent to the annual energy consumption of 40,000 cars.

Mr. Derry further noted that the east and west routes traverse about the same length of the boreal forest zone. However, the western route also traverses several hundred kilometers of the best agricultural soils and the most favourable agro-climatic zone in the Province. With respect to the impact on First Nations communities, 16 communities would be affected by the eastern route and 15 by the western route, i.e., essentially the same number. Neither route traverses any Aboriginal reserve land, although both traverse the traditional lands of Aboriginal people. Mr. Derry stated that First Nations Chiefs on the east side of Lake Winnipeg are expressing increased interest in the eastern route for Bipole III.

The Coalition questioned the alleged impact of the eastern route on having the region designated as a UN World Heritage site, noting that winter roads are being upgraded to all-weather roads along the east side of Lake Winnipeg and the right-of-ways will have a greater impact than a power line. Once roads have been established, a common corridor that includes the road and the Bipole III makes sense.

Mr. Derry also noted that a route on the east side of the province provides much higher reliability and protection against risk from wind and ice storms than a west side route. He stated that if Bipole I and II are damaged, the eastern route for Bipole III is twice as effective as the western route for supplying electricity to Southern Manitoba and meeting the export commitments to the United States.

Mr. Derry summarized that the HVDC Bipole III transmission line route along the west side of the province was dictated by the provincial government. Based on technical, environmental and social and economic grounds, the Coalition considers the selection process for the western route to be seriously flawed and urges the eastern route be selected as the preferred route for Bipole III.

2.3.5 Amsted Rail – Mr. Shirley

Mr. Shirley, the Chief Operating Officer of Amsted Rail, stated that as a result of the worldwide economic downturn, Griffin Wheel Company's business environment has changed dramatically. It had to idle its Winnipeg wheel plant in October 2009, and also reduce the operating schedules of its remaining three facilities. He mentioned that since the market has not yet recovered, further actions must be taken to ensure the viability of the Winnipeg operation. Amsted Rail's plan is to restart the Winnipeg facility.

Amsted Rail is asking for MH's consideration to make the demand concession a permanent concession rather than leave it as the existing temporary loan. This Presenter further asked that consideration be given to extending the concession until May of 2010 for Griffin Wheel Company and other companies in Manitoba who are still struggling with the economic recovery.

Mr. Shirley stated his company is a large user of energy, but that the peak demand charges that must be paid during periods of reduced plant operation erodes the company's ability to compete with offshore competitors. Amsted Rail is moving ahead with implementation of its plan to restart its Winnipeg plant based on the assumption that the PUB will assist with the aforementioned requests.

2.3.6 Canexus – Mr. Turner

Mr. Turner, the plant manager at Canexus in Brandon, presented on behalf of both Canexus and MIPUG, of which Canexus is a member. He requested the demand billing concessions be made permanent, as requested by MH. He also urged the Board to implement cost-based rates.

Mr. Turner noted some of the benefits that MIPUG industries bring to Manitoba. They employ in excess of 4,000 people directly in the Province, at more than twice the average industrial wage in Manitoba. They have assets with a replacement value of over $2 billion dollars. They support countless numbers of regional networks of secondary industries, retail companies and hospitality services in their communities. Most of the MIPUG industries account for a large part of the employment opportunities in rural and northern areas of the Province. Corporate taxes are estimated to be in the range of $75 to $100 million, and individual employees of MIPUG industries pay in excess of $50 million collectively to the Provincial and Federal governments in personal income taxes.

Mr. Turner stated that the purpose of MIPUG is to allow industries to work together on issues related to rates and electricity supply in Manitoba. He noted that the challenges faced by MIPUG industries, for the most part, relate to being geographically isolated from markets. The steadily appreciating Canadian dollar also makes it difficult to keep manufacturing costs low and continue to be competitive.

In order to remain competitive in external markets, Mr. Turner stated that key interests must be protected, such as access to a reliable supply of energy, as well as stable and predictable energy rates, which are critical to running production processes. MIPUG industries must estimate their product prices based on their production costs, knowing that they can rely on paying a certain amount for energy in a given year.

MIPUG has expressed an interest in keeping firm power rates relative to the cost of providing service to the specific class. Revenue-to-cost-coverage (RCC) ratios for each class should be moved within the zone of reasonableness at 95 to 105 percent. Currently, the RCC ratio is 112 percent. To keep rates predictable and stable, the Cost of Service Study (COSS) should be a reliable, verifiable method of assessing the costs for each class.

The downturn of markets all over the world in the fall of 2008 placed significant market pressures on MIPUG's members. Some members had to implement efficiency measures to remain competitive and, in another case, a plant closure was scheduled.

Canexus, as well as all other chlorate producers utilizing the electrolytic process, needs electricity to boil off water in order to produce its product, and electricity accounts for approximately 65 to 70 percent of its variable costs.

Mr. Turner stated that chlorate competitiveness is determined by three key considerations, namely power price stability and availability, salt price and availability, and transportation to markets. Power is the most important factor due to the large amount required for electrolysis. Canexus consumes about $49 million per year of MH power, and strives to utilize power efficiently. Mr. Turner noted that Canexus is continually trying to upgrade its process and was able to reduce the power brought into the plant by about 250 kilowatt hours per tonne over the years by implementing energy efficiency measures within the plant site.

2.3.7 Individual Presenters

Mr. Carriere

Mr. Carriere presented his views on what he considered MH's abusive rate increases. He mentioned there are over 136,000 people in Manitoba who rely on electric heat in the winter to heat their homes and it can be very costly for a senior on a modest pension. Mr. Carriere stated MH should look at giving people who use electric heat in the winter their own lower rate during the winter months. He suggested another option would be to offer a rebate at the end of winter on the use of electric heat.

He stated he would like to see the PUB refuse Manitoba Hydro any more increases since MH is doing well financially. If MH is having a financial problem, he suggested it should look at cuts to management and the workforce to keep the rates at a reasonable cost. In his opinion, it is time for MH to look into efficiencies in its own backyard and stop asking for increases every year.

Mr. Gray

Mr. Gray presented his comments related to the inverted rate structure of MH. Mr. Gray stated that he had converted his personal household from a gas furnace, dryer, and hot gas hot-water heating to an all-electric system. The reasoning behind this decision was that hydroelectricity provides far less environmental damage, less pollution, and much lower production of greenhouse gases. In addition, hydroelectricity, unlike natural gas, is a renewable resource, and under MH, provides stable long-term pricing.

Customers with electric heating are necessarily users of greater amounts of electricity. The introduction of the inverted rate structure has impacted disproportionately and unfairly on those customers who have chosen electric heating, as well as on many rural customers that have no access to natural gas.

Mr. Gray proposed that the PUB consider excluding the inverted rate structure step rate for those residential customers using electric heating. The same rate treatment could also be applied to residential customers with geothermal heating as an additional incentive to adopt geothermal heating, one of MH's objectives.

Mr. Gray also noted that for an increasing rate structure or peak-load pricing to be effective, customers need to know two things: what their energy consumption is on an ongoing basis, and, in addition, what to do in order to reduce their energy consumption. Residential customers would require something like an energy meter mounted adjacent to thermostats showing energy consumption and cost on a continuing basis.

Mr. Gruhn

Mr. Gruhn stated his objection to the increase being sought by MH due to the ongoing financial problems with the Corporation. Mr. Gruhn spoke of the need for a public hearing to be held in Brandon, to allow the PUB to hear from ordinary rural consumers as well as those in the city.

Mr. Jones

Mr. Jones provided comments on how he was being penalized for having installed electric heat. Special consideration should be given to those households that use electricity for heating.

Mr. Jones stated the rate structure should be set at a fair and realistic level according to the average consumption of an electrically heated house rather than an arbitrary 900kWh limit. Otherwise, electrically heated homes should have a separate rate structure. MH has a responsibility to customers they convinced to install electric heat and that responsibility should be recognized by the PUB in any planned rate adjustments.

Mr. Ciekiewicz

Mr. Ciekiewicz provided the Board with a written presentation together with his oral presentation. The presentation by Mr. Ciekiewicz covered a variety of topics – from MH's new office tower to risks, including an emphasis on inverted rates and the impacts on the MH customer using electricity for space heat.

Mr. Ciekiewicz also provided the Board with a series of recommendations that can be found starting at page 387 of the Transcript.

3.0.0 FINALIZED RATES

3.1.0 ORDER 99/11

Of particular significance and drawn from Order 99/11 is the Board's continued finding that MH failed to discharge its statutory and legal onus in the substantiation of its GRA rate increase requests:

> *"… 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 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." (Order 99/11 – page 4)*

As a consequence, the Board denied MH's request to finalize the 2.9% interim rate increases which were implemented on April 1, 2010 and also denied MH's request to finalize the 2.0% interim rate increases which were implemented on April 1, 2011. MH's requested Board approval of a further finalized average consumer rate increase of 0.9% as of August 1, 2011, which was also denied.

On January 4, 2012, the Manitoba Court of Appeal granted MH leave to appeal the issuance of the Board's subpoena for MH's export contracts. This appeal is currently pending, and the export contracts have not been provided by MH. Therefore, the Board remains of the view that to date MH has either failed or refused, and continues to fail or refuse, to provide information that the Board considers critical to its mandate of fixing just and reasonable rates for the services provided by MH.

3.2.0 RATES AND MH'S 75:25 DEBT TO EQUITY TARGET

Beyond debate is the Board's jurisdiction and mandate to set just and reasonable rates for MH that are in the public interest. The public interest includes consideration of the fiscal health of the Utility as well as the impact of rates on consumers.

MH defends its requested rate increases of 2.9% for 2010/11 and another 2.9% for 2011/12 as maintaining the appropriate balance between customer sensitivity and fiscal responsibility. The fiscal responsibility includes taking note of MH's plans for $20 billion of major investments in new generation and transmission systems in MH's self-described "decade of investment" to the year 2020. It is during this "decade of investment" that MH foresees its debt-to-equity ratio eroding from the current 74:26 level to 80:20, even with annual rate increases in excess of the forecast rate of inflation.

Since 2004, the Board has continually approved rate increases for MH that have been in excess of inflation and also in excess of MH's own rate increase requests. These rate increases have in large measure contributed to the annual Net Income of the Utility and therefore to the Retained Earnings of MH. The rate increases further enabled MH to achieve its financial target of a 75:25 debt-to-equity ratio a full four years ahead of the target date sought by MH's Board of Directors.

The intention of reaching a debt-to-equity target of 75:25 was to afford consumers rate relief aligned to the rate of inflation once the ratio had been met – together with prudent management of MH's operating and other expenses. While the Board has had, and continues to have, serious concerns with the composition of what MH categorizes as "Equity", the overall target of 75:25 remains valid.

3.3.0 BOARD FINDINGS

3.3.1 Final Rates for 2010/11 and 2011/12

The Board is not prepared to finalize the existing interim rate increases of 2.9% effective April 1, 2010 and 2.0% effective April 1, 2011. The Board further denies the requested

0.9% average rate increase effective August 1, 2011. Rather, and based on the totality of the evidence before the Board, including MH Senior Vice President Mr. Warden's testimony that MH is now in its best financial position in the Utility's history, the Board finds that rate increases aligned to the forecast rates of inflation for 2010/11 and 2011/12 are just and reasonable and in the public interest. The Board will therefore approve, on a final basis, a 1.9% average rate increase effective April 1, 2010 and a further 2.0% average rate increase effective April 1, 2011.

The Board does not accept MH's contention that the rates proposed by MH represent a proper balance between customer sensitivity and fiscal responsibility. MH states that it is important that MH maintain an adequate level of retained earnings and that rates be raised gradually even during periods of exceptional water-flows. MH's application also seeks a higher level of retained earnings to provide funding for capital investments and reduce the need for borrowing, which MH states will in turn reduce the financing costs that ultimately must be recovered from ratepayers.

In the Board's opinion, MH's view of fiscal responsibility is skewed by blind adherence to a future major capital plan that has not been fully tested before an independent tribunal considering the "Needs For And Alternatives To" such a major capital expenditure plan (NFAAT). Such an NFAAT should include all facets of MH's capital expenditure plans, including the export contracts MH has entered into or plans to enter into to allow for the advancement of its capital expenditure plans.

The Board was reminded by CAC/MSOS to go back to first principles regarding its rate-setting jurisdiction with respect to MH. CAC/MSOS submitted that the Board's jurisdiction to fix just and reasonable rates carries with it the need to meet the general public interest made up of (1) the interests of ratepayers and (2) the financial health of the utility.

CAC/MSOS submitted that the final rate order should address both short-term test year revenue requirements and the long-term issues facing MH that are of concern to the

PUB, in particular respecting the “decade of investment.” CAC/MSOS further submitted that rate-setting at this time must also take into account the ongoing economic uncertainty and financial stresses existing in Manitoba on all consumers, including individuals, businesses and large industry.

The Board’s role, according to CAC/MSOS, must involve ensuring that MH’s forecasts are reasonably reliable, ensuring that actual and projected costs incurred are necessary and prudent, assessing the reasonable revenue needs of the Corporation in the context of the overall general health of MH, determining an appropriate allocation of costs between classes, and setting just and reasonable rates in accordance with statutory objectives.

The Board endorses these principles and the objectives as set out above that must inform it in the present circumstances when fixing rates for the test years in question. As set out in this Order, the Board is not satisfied that it has sufficient proof from MH, upon consideration of all of the evidence, to support a final approval of rate increases as sought by MH. In this GRA proceeding, MH has failed to substantiate the reasonableness of its capital plans and the expected revenues to support such a capital plan. As such, the Board cannot, and will not, endorse MH’s rate increase requests as applied for. However, the Board has determined that MH must receive inflationary increases for the test years to avoid erosion of its capital structure in the test years.

While MH has not made its case for the higher rate increases it requested, its financial position, arising from its Operating Results for the years ending March 31, 2010, 2011, and 2012 is significantly better than when MH filed its GRA in both MH’s own assessment and the assessment of the Interveners. For the fiscal year ending March 31, 2010, MH was forecasting $121 million of Net Income. Actual Net Income was $43 million greater, at $164 million. For the fiscal year ending March 31, 2011, MH was forecasting $78 million of Net Income. Actual net income was $65 million greater, at $143 million. Finally, for the fiscal year ending March 31, 2012, MH was forecasting

$87 million of Net Income. In its latest Financial Report, MH now projects Net Income at least $42 million greater, at $130 million.

The finalized rates for the 2010/11 and 2011/12 test years do not equate to the interim rate increases that were approved in Board Orders 18/10, 30/10 and 40/11. The Board is of the view that the most expeditious way to account for the differences between the interim and final rates is for MH to establish a deferral account to track, by customer class, the difference between what was collected under the interim rates and the amount that would have been collected pursuant to the rates now finalized. That difference is to accrue interest at MH's short term borrowing rate, for the benefit of MH's consumers.

Rather than requiring MH to immediately reduce its rates, the Board orders that the rate differential between what was approved on an interim basis and what has now been finalized shall be quantified by MH and remain as an interim rate, with its associated revenues being accumulated by customer class, with accrued interest, in the previously prescribed deferral account.

The reasons for not immediately requiring rate decreases and refunds extend beyond the administrative expense and potential inequities due to customer class changes. MH had indicated that the Utility would likely be seeking further rate increases, effective April 1, 2012 – subject to confirmation by the Board of Directors of Manitoba Hydro.

While the PUB is aware that no new GRA has been approved for filing as of the date of this Order, the PUB will need to know definitively of MH's intentions in that regard to enable it to further consider its approach to what will be a new interim rate and an accumulating deferral account. As always, MH and Interveners are at liberty to make submissions to assist the Board in its deliberations on this issue.

3.3.2 Final Surplus Energy Program (SEP) Rates

Included in MH's GRA Application is the Utility's request for final Board approval of all weekly SEP *ex-parte* rate orders (as listed in Appendix 10.7 in MH's GRA filing and outstanding to the date of this Order). There was no opposition to MH's request.

The SEP achieved sales of approximately 20 GWh in the November 2009 to October 2010 time period. It appears that the SEP was only modestly profitable (less than 5%) at an average revenue rate of 3¢/kWh. Historically, SEP revenue has exceeded MH's marginal cost by 10-20%, indicating that this current situation will continue to be monitored.

The Board approves as final all outstanding SEP weekly interim rate Orders from and including Order 67/08, up to and including the SEP Order issued in the week before this Order was issued.

3.3.3 Final Curtailable Rate Program (CRP) Orders

MH seeks final Board approval of CRP Orders 46/09 and 63/11, which provided interim approval of reference discount rates effective on and after April 1, 2009. No opposition to MH's request was raised during the GRA. The value MH places on CRP apparently relates primarily to winter capacity relief in years when domestic peak demand approaches system capacity.

While the Board will approve as final all interim CRP Orders (Orders 46/09 – 63/11), the Board does note that because MH normally markets its expected summer surplus capacity by the preceding February, there is a low, yet still real probability of export-related summer capacity shortfalls. Accordingly, the Board will seek additional information on this issue at the next GRA.

3.3.4 Temporary Billing Demand Concessions

MH has requested final approval of Order 126/09, which resulted from MH's Application for Temporary Billing Demand Concessions for General Service Medium (GSM) and

General Service Large (GSL) customers. The apparent impetus for this rate relief program was the economic downturn. MH sought concessions for industrial customers when the single 'unit cost' of their energy increased by more than 10% due to demand charges that would be incurred regardless of the energy consumed.

Unlike residential electric customers, GSM and GSL customers pay a monthly demand charge that is not directly scalable with reductions in electricity consumption. This means that even when these customers temporarily close production facilities or otherwise reduce consumption due to the global economic downturn in demand for their products, their energy bill does not decrease proportionally to the reduction in electricity consumption. MH's rate structure for these GSL and GSM customers includes recovery of MH's fixed costs (for property, plant and equipment) through the demand charge levied to high-volume customers.

While the Board granted temporary relief through Order 126/09, MH requested that the temporary concessions be made permanent under the program and not subject to being repaid by the GSL and GSM customers.

While under MH's proposal, the GSL and GSM customers would not have to repay the temporary concessions, those fixed charges must still be attended to by MH. In essence, the Board concludes that other customer classes would be expected to make up the shortfall in MH's retained earnings.

In Order 126/09 the Board indicated that for the temporary relief to be finalized, and perhaps forgiven, additional information would have to be made available to the Board. In that Order, the Board even set out a list of the types of additional information that were to be provided should MH seek finalization or forgiveness of the temporary demand billing concessions. MH either chose not to, or was unable to, obtain and provide such additional information to the Board. As such, the Board is not persuaded to grant the relief requested. Based on the evidence before the Board, and considering the submissions from parties choosing to address this issue (with Interveners on each side of this issue), the Board will not approve the forgiveness of the temporary demand billing concessions.

That portion of the qualifying customers' electricity bills that was temporarily deferred and carried at the equivalent of MH's cost of short-term borrowing as interest is now required to be repaid to MH. At the next GRA, MH is to report on the collections of the previously and temporarily deferred amounts.

4.0.0 MH'S DEVELOPMENT PLANS

4.1.0 MH'S CURRENT PREFERRED DEVELOPMENT PLAN

In defining its preferred and alternative Development Plans, MH relied on information from its various electricity planning documents, which are typically prepared annually and include:

- Integrated Financial Forecasts (IFFs);
- Capital Expenditure Forecasts (CEFs);
- Domestic load forecasts;
- External consultant panel survey on export pricing expectations;
- Power Resource Plans (PRP);
- Existing export contracts; and
- Pending export sales contracts (Term Sheets).

A key component of the PRP process involves defining "minimum dependable energy". Minimum dependable energy arises primarily from hydraulic generation but can also be sourced from non-hydraulic generation such as MH thermal, MH-purchased windpower generated in Manitoba, demand reductions resulting from efficiency improvements, demand side management (DSM), and imports from American counterparties. In MH's plans, projected domestic load (i.e., the electricity requirements of MH's Manitoba customers) is to be provided only from defined dependable energy resources. To the extent that minimum dependable energy exceeds the projected domestic load, any projected surplus becomes available for "firm" export contract sales, as opposed to opportunity exports. Firm export contracts are usually of relatively short duration relative to the life expectancy of a hydraulic generating station.

Circa 2007, MH indicated that Term Sheets had been entered into with American utilities calling for the following firm sales to export customers for various years, commencing in 2015:

- Northern States Power (NSP) - 375/325MW (2015-2025);
- Wisconsin Public Service (WPS) - 500 MW (2018-2033); and
- Minnesota Power (MP) - 250 MW (2020-2035).

To facilitate these projected export contract sales, MH's PRPs involve projected "in-service" (projected construction completion) dates for new facilities allowing for "dependable" hydraulic generation for MH's preferred and alternative development plans for various vintages of MH's PRPs.

Under the 2009/10 PRP, which was reviewed by the Board at this GRA, MH showed a proposed plan to expend capital to construct the following:

- Bipole III transmission line;
- Keeyask G.S; and
- Conawapa G.S.;

These three capital projects were to be undertaken together with other major new generation and transmission capital expenditures for:

- A 500 KV USA Interconnection;
- An expansion or upgrade of transmission facilities south of the U.S. border;
- Additional north-south AC transmission capacity in Manitoba; and
- The reconstruction of the Pointe du Bois spillway and powerhouse.

Prior to the conclusion of the GRA Hearing, MH advised of changes to its plans, most notably the recognition of a reduction in the WPS commitment from 500 MW to 100 MW, with the 15 year agreement being pushed back to 2021.

4.2.0 EVOLUTION OF MH'S DEVELOPMENT PLANS

In MH's 2004/05 PRP, MH modelled the following alternative new resource concepts, each assuming a 2024 in-service date that would follow the 200 MW Wuskwatim Generating Station's (G.S.) then-projected 2010/11 in-service date:

- Equivalent outputs from single cycle combustion turbines (SCCTs);
- A 10 turbine 1250 MW Conawapa G.S. to generate 4,500 GWh of dependable energy;
- A 5 turbine 625 MW Conawapa G.S.[1] to generate 4,500 GWh of dependable energy; and
- A 600 MW Keeyask G.S. to generate 2,900 GWh of dependable energy.

Anticipating about 3,500 GWh of firm contract commitments with its American counterparties, MH concluded that a 10 turbine Conawapa G.S. represented the most cost-effective next plant in service. There is no mention in the 2004/05 PRP as to how Combined-Cycle Combustion Turbines (CCCTs) would compare to either SCCTs or the hydraulic alternatives.

In its 2008/09 PRP, MH reconsidered the next plant in-service sequence and, based on projected higher 2008 domestic load forecasts and new export contracts beyond 2015 (500 MW to Northern States Power (NSP) / 100 MW to Minnesota Power (MP) / 500 MW to Wisconsin Public Service (WPS)), suggested the following builds:

[1] A 5 turbine Conawapa G.S. was projected as providing for sufficient capacity for full utilization of dependable river flows.

- Keeyask G.S. 630 MW 2018/19 in-service; and
- Conawapa G.S. 1,300 MW 2022/23 in-service.

This same PRP presented an alternative development plan in case the WPS and MP sales did not materialize. The alternative development plan projected:

- Additional contracted imports up to and including 2015;
- The construction of a 400 MW CCCT plant for a 2019 in-service date; and
- A 1,300 MW Conawapa G.S. for a 2021 in-service date.

In its 2009/10 PRP**,** MH projected:

- Construction of a 630 MW Keeyask G.S. for a 2018/19 in-service date;
- A 1,300 MW Conawapa G.S. for a 2022/23 in-service date;
- A 1,000 MW export inter-connection for 2018/19;
- A 750 MW import inter-connection for 2018/19; and
- Additional Manitoba north-south transmission (in support of Bipole III), to address a drought scenario similar to the one encountered in 2003/04.

This new recommended development plan was deemed necessary by MH to service its pending and/or projected Term Sheet sales of 500 MW to WPS and 250 MW to MP (which is the same scenario as was contained within MH's 2008/09 PRP). The construction of a 400 MW CCCT facility for 2018/19 was deleted, presumably reflecting a 1,000 GWh reduction in MH's domestic load forecasts.

In the absence of WPS and MP Term Sheet sales, MH's 2009/10 alternative development sequence would presumably have been:

- No Keeyask G.S.;
- Construction of a 1,300 MW Conawapa G.S. for 2021/22 in-service; and
- Deferral of the construction of a 400 MW CCCT facility to a 2033/34 in-service date.

In its 2010/11 PRP, MH deferred both Keeyask G.S. and Conawapa G.S. by one year (2019/20 and 2023/24 respectively) in its recommended plan, and Conawapa G.S. by one year (to 2022/23) in its alternative plan. The export interconnection was also set back by one year (to 2019/20). In the alternative plan, with no MP/WPS contracts and only a 375/325 MW sale to NSP, only Conawapa would be built by 2022/23, with a 460 MW CCCT plant to be added in 2033/34.

In June 2011, MH filed with the Board its 20-year financial outlook (OL 10-2), updated to reflect its most recent accepted revised capital cost estimate for Bipole III.

In July 2011, referencing a Manitoba Government press release of May 25, 2011, MH confirmed that the amount of export power for the proposed long-term sale agreement with WPS had been reduced from 500 MW to 100 MW. This reduction reduces the immediate need for a 1,000 MW export and 750 MW import intertie capacity. The reduction, if not reversed, could allow for a further deferral of the anticipated in-service date for Conawapa G.S. to a date beyond 2024/25.

4.3.0 FIRST NATION INVOLVEMENT IN THE DEVELOPMENT PLAN

4.3.1 Wuskwatim

Wuskwatim G.S. represents Manitoba’s first new hydroelectric development since the late 1980s, and the first in Manitoba structured as a partnership between MH and a First Nation, namely the Nisichawayasihk Cree Nation (NCN). The project is to be developed by the Wuskwatim Power Limited Partnership (WPLP), an equity partnership between NCN and MH.

The two limited partners (MH and NCN) are to invest equity in the WPLP by subscribing for ownership units to represent 25% of the total capital cost of the project. The WPLP agreement allows for NCN, through its wholly owned Taskinigahp Power Corporation (TPC), to subscribe for up to a 33% stake in the equity partnership units.

MH, through a holding company that serves as general partner, would hold a 0.01% interest in WPLP, with MH in its capacity as limited partner holding the balance of 65.99% directly.

The assets of the WPLP are to consist of the Wuskwatim G.S. and required working capital. MH is to lend WPLP the funds required to build the generating station. Based on the Corporation's current estimated cost of constructing Wuskwatim, and excluding the transmission component, MH projects lending WPLP $927 million. The funds are to be required to build the generating station, and represent approximately 75% of the cost of the project (the remaining funding to be through WPLP's equity partnership units).

MH assumes that TPC will subscribe for the full 33% of the equity ownership interest permitted. Based on the current construction cost estimate for the generating station, TPC's cost for the partnership units would be $102 million. According to the agreements, TPC will invest up to $34 million of its own capital and can borrow up to $68 million from MH to fund the balance. MH advised that NCN has yet to commit to the full 33% ownership interest in WPLP and will not be required to make a decision on its stake in the partnership until the dam is put into service.

Revenues generated from the project are to be allocated to WPLP from MH's overall revenues, based on an agreed-to (between NCN and MH) formula utilizing average export prices for on-peak and off-peak sales. MH indicated that the determination of the average export price will include the export revenue from the new NSP agreement as well as from contracts reached with Wisconsin Public Service and Minnesota Power, along with any opportunity sales.

Revenues are to be adjusted as changes in export prices are experienced and realized, and are to be based on the actual output of Wuskwatim G.S., reduced by the average system line loss rate for the MH system (currently 10%). WPLP is to pay MH 3% of the WPLP's gross revenues, to contribute towards the marketing and transmission costs and risks borne by the Corporation.

MH will be fully responsible for the operation of the generating station and related transmission facilities, and will charge WPLP for its incremental operating costs. MH will make no cost allocation to WPLP for system generation and transmission. Control Center costs will not be directly charged to the project but be included in the overhead charge to the project.

The Wuskwatim Project Development Agreement allocates MH's overhead costs at a rate of 21% as opposed to the "normal" 29%, this reduction allowing for the exclusion of a share of costs related to MH's Winnipeg facilities and computer systems not expected to be utilized by the project.

Finance costs incurred by the Corporation related to the loans it will take on to allow it to make loans to WPLP to build the generating stations are to be recovered, at cost, from WPLP. The financing cost related to loans to WPLP has been estimated at 6% interest, based on MH's expected long-term cost of borrowing of 5% plus a 1% Provincial debt guarantee fee.

The WPLP must maintain a 75:25 debt-to-equity ratio, except for the first 10 years of operations during which an 85:15 debt-to-equity ratio will be allowed. If the partnership's debt-to-equity ratio falls below the above parameters, there is a requirement for further cash contributions from WPLP partners based on their respective ownership interest in the partnership.

The development agreement between Hydro and NCN allows for advances on dividends to NCN, even during loss years and/or when the equity threshold test has not been met. The advances are to be limited to 5% of the actual cash invested by NCN, and are to be repaid by NCN out of forecast future distributions.

In addition to the generating station, Wuskwatim requires incremental transmission facilities. MH is to build the required transmission, at an estimated cost of $320 million, the cost of which will be recovered from WPLP by way of repayment of principal and interest over a 50 year term. In addition, the operating costs of the transmission facilities will be charged to WPLP.

4.3.2 Keeyask

Like Wuskwatim (see section 4.3.1), Keeyask G.S. is to be developed through a First Nations partnership. In this case, the project will be developed and operated through the Keeyask Hydropower Limited Partnership (KHLP), a partnership between MH on the one hand and (1) the Tataskweyak Cree Nation and War Lake First Nation, acting as Cree Nation Partners, (2) the York Factory First Nation, and (3) the Fox Lake Cree Nation (collectively, the Keeyask Cree Nations or KCN) on the other hand.

The limited partners (MH and each of the four KCN) are to subscribe for equity units in the limited partnership, which is to represent 25% of the total capital cost of the Keeyask G.S. The partnership agreement allows for the KCN to collectively subscribe for up to 25% of equity units in the partnership. MH, through holding company acting as general partner, would have a 0.01%. In its capacity as a limited partner, MH would hold the remaining balance of 74.99% directly.

Each of the KCN partners can choose different ownership positions in the Limited Partnership by way of a combination of common equity and or a preferred equity share ownership. KCN partners have the option to acquire preferred equity shares amounting up to a 2.5% equity interest. MH will not provide financing for preferred equity share investments.

The minimum cash investment to be made by the KCN partners is $12.5 million, with a maximum cash requirement of $25 million. MH will lend the KCN a maximum amount equal to the difference between $25 million and the amount it takes to acquire a 17.5% common equity ownership in KHLP, financed by both KCN and MH equity loans. If KCN invests only the minimum cash investment, equity loans will be available to take an 8.75% common equity interest. The equity loans are to be at a 30-year loan rate plus 2%, payable over a 50-year term.

The assets of the Limited Partnership will consist of the Keeyask G.S and required working capital. MH is to lend KHLP the funds to build the generating station. Based on the Corporation's current capital cost estimate of constructing Keeyask, excluding transmission investments, MH will be required to lend KHLP $4.2 billion to build the generating station, representing 75% of the cost of the project. The balance of approximately $1.4 billion is to be funded by the equity contributions of the partners.

MH will be responsible for the operation and maintenance of the Keeyask G.S. and related transmission facilities. KHLP will be assigned the costs related to management and operations of the Keeyask G.S., including all indirect costs and expenses, in a manner consistent with how Hydro allocates its indirect costs and expenses to other generating stations that are wholly owned by MH.

KHLP will attract no water rental fees, amortization or finance costs related to MH's operations. However, KHLP will be assessed the finance costs incurred by MH related to the loans required to build the generating station. During the construction period, the loan will bear interest at the floating rate plus 2% and the debt guarantee fee. Upon completion of construction, the loan will be converted to a 30-year rate plus 2% and the debt guarantee fee. Repayment will be made be from a share of the revenue generated by the facility over a 50-year term.

MH will provide an Operating Credit Line to fund any cash calls that may occur to keep the capital structure of the Limited Partnership within established parameters of a 75:25

debt-to-equity ratio, which is allowed to rise to an 85:15 ratio during the first ten years of operations. Advances made under the Operating Credit Line would bear interest at the ten-year rate plus 2% and the debt guarantee fee.

With respect to the transmission costs that are to be paid by KHLP, the full extent of the transmission arrangements have not been fully determined, but the partnership agreement envisions that to the extent that any incremental transmission facilities are required for the Keeyask G.S. KHLP will be responsible for their capital and operating costs, including OM&A costs.

KHLP will not be responsible for any of the capital or operating costs, including OM&A costs, of Bipole III (if built), nor any costs to build or operate additional AC transmission or associated stations related to north / south transmission. KHLP will also not be allocated any costs related to interconnection between Manitoba and other jurisdictions. Such costs may be incurred to allow Keeyask-generated power to be delivered to export markets.

4.4.0 DEPENDABLE ENERGY RESOURCES

In defining its recommended development approach, MH contended that its "Dependable Energy" resource should include:

- Hydraulic Generation

  (21,100 GWh, to increase to 22,300 GWh in 2012/13 when Wuskwatim is expected to be in service);

- Thermal Generation

  (4,100 GWh, to decrease to 3,300 GWh after 2018/19, when the Brandon Coal plant is to be decommissioned);

- Wind Generation

(800 GWh, with both St. Leon and St. Joseph in-service);

- Reductions in required supply due to DSM measures

  (800 GWh in 201516, to increase to an expected 1,000 GWh by 2019/20); and

- Imports

  (2,700 GWh, this from a combination of contracted (firm) and opportunity market purchase (non-firm) imports).

MH has not specifically defined its “acceptable” levels of non-hydraulic resources that may be employed in satisfying domestic load requirements under the Utility’s projected “Dependable Flow” scenario. However, from the various PRP sequences filed, it appears that a 5,000-5,500 GWh shortfall of dependable hydraulic generation relative to base domestic load would “trigger” or require new hydraulic generation to be brought into service.

When the Utility’s firm energy export obligations, which are typically 2,000-3,000 GWh per year, are factored in, MH forecasts a dependable hydraulic energy shortfall of 7,000 to 8,500 GWh, which, for both economic and scheduling reasons, may require up to 8,000 GWh of imports and other power purchases in the worst-case year (i.e. in drought conditions).

In the absence of new firm export contracts, Keeyask G.S. could possibly be deferred by five or six years, the deferral to be provided for by maximizing imports. Similarly, in such a circumstance, Conawapa would only be required for domestic requirements circa 2030/31.

4.5.0 OTHER SCENARIOS

4.5.1 Overview

Circumstances have changed since MH, in its 2008/09 PRP, projected that new hydraulic generation would be required in 2018/19. Domestic consumption has declined by more than 1,500 GWh/year at a time the export market has "shrunk". As a result, in the absence of new developments requiring large additional load, the limited deferral of new hydraulic generation may be possible without curtailing the NSP/MP/WPS sales agreements. Further, if these prospective agreements were not consummated, MH might be able to defer new generation until 2025/26 by serving domestic load only from existing domestic hydraulic/thermal/wind generation and present import arrangements.

In MH's 2008/09 Alternate Development Scenario, MH considered the construction of a 400 MW CCCT plant in lieu of constructing Keeyask G.S. for an in-service date of 2018/19. With the then-prevailing natural gas price of $8.00/GJ, the unit operating output cost for the CCCT option was estimated at 5.50¢/kWh. However, at current natural gas prices, those being in the range of $4.00/GJ, the unit operating cost would be significantly lower, perhaps less than half the 10¢/kWh expected on-line cost of Keeyask G.S. production.

MH has included Bipole III in all of its development scenarios, and Bipole III must be in place to accommodate Conawapa G.S. output. However, it may not be required for Keeyask G.S. output, assuming average flow levels.

MH contends that Bipole III is required for domestic reliability reasons, particularly as such relate to the potential for an extended outage of both Bipoles I and II. In MH's CEF03 and CEF04, MH contemplated building an east-side transmission facility without new HVDC converters at a cost of $0.5 billion, to deal with reliability concerns. But in its 2004/05 PRP, MH included HVDC converters, and MH's CEF05 included a provision of $1.8 billion for Bipole III in anticipation of building Conawapa G.S. (or Keeyask G.S.) for a 2024/25 in-service date, to meet then-projected future domestic load requirements and, initially, to provide about 4,500 GWh of “surplus” firm energy for the export market.

In MH’s 2004/05 PRP, the Utility employed a SCCT thermal generation scenario as a base for comparison of its new generation alternatives. As well, Bipole III costs were excluded from the analysis. The construction of a CCCT plant was not considered, despite the typical operating costs (including fuel) of such a plant being 3-5¢/kWh lower than for a SCCT plant.

Since 2004, MH’s planning has not considered any non-hydraulic generation, such as possibly lower-cost gas plants or more wind generation to augment hydraulic capacity scenarios to meet both domestic load and reliability concerns. A wider consideration of options could include:

- Revisiting an east-side HVDC transmission line without HVDC converters as a means of improving transmission reliability for existing northern hydraulic generation;

- Examining the possible role of a 400/800/1,200 MW CCCT natural gas thermal generation plant, which, potentially, could allow for the further deferral of not only new hydraulic generation but also Bipole III, for at least a decade; and

- Firm price import contracts, focused on natural gas rather than coal- or gas-generated electricity.

The end product of the information from all these planning documents is MH’s “road map” as to future major capital projects (generating stations and transmission lines) that will be required to meet MH’s future domestic loads and firm export commitments. There is subjective decision making involved – together with numerous assumptions – that underpins any current version of MH’s Preferred Development Plan.

The significance/importance of examining and testing those assumptions and decisions cannot be overemphasized. With capital costs and financing costs in the tens of billions of dollars, the stakes are high for the domestic ratepayer who is at risk to bear the costs.

4.5.2 Keeyask G.S. without Bipole III

It is MH's position that Keeyask G.S. cannot proceed without Bipole III in place to transmit the full Keeyask plant capacity when water levels are well above dependable flow levels. MH indicates that Bipole I and II cannot operate on an extended-time basis at their full capacity of 3,854 MW, as 500 MW of Bipole capacity should be kept in reserve for maintenance and/or forced outages of valve groups. As such, the existing HVDC lines are only capable of 3,354 MW, delivering 29,400 GWh/year. This, in effect, means that the combined 4,200 MW capacity of the Keeyask/Kettle/Long Spruce/Limestone generating stations could only operate at an 80% capacity level.

It appears that other than in 2005/06 MH's output from the three existing lower Nelson River Plants has not exceeded 80% of their capacity.

Recently, MH has also suggested that an additional 208 to 838 MW of transmission capacity would be required once Keeyask is in service to match total generation capacity and provide system reserves. In MH's OL 10-2, MH's alternative to a 2,000 MW Bipole III was 2,000 MW of natural gas generation. Staggered in-service dates of individual 400 MW CCCTs to postpone the need for Bipole III do not appear to have been considered.

4.5.3 Natural Gas Generation Instead of Bipole III

In MH's 20 year financial outlook (OL10-2), MH provided a comparison of two reliability alternatives, namely Bipole III vs. a gas-only scenario. The brief analysis covered only the initial capital costs and annual fixed operating costs for SCCT plants, not a CCCT plant. It did not contemplate and model finance, depreciation and OM&A costs and revenue from a CCCT natural gas generation system, or the advantages of such additional capacity. As well, the stepped additions of 400 MW CCCT units were not considered. MH similarly did not provide a net present value analysis dealing with different service lives of the various components or the incremental revenue potential that CCCT units could achieve.

It appears that MH has not to date reviewed and considered a CCCT generation scenario that could supplement Keeyask G.S. while deferring Bipole III for at least a decade. Without the 500 MW WPS contract, the timeframe for Conawapa G.S. could conceivably be extended beyond 2029/30. Without Conawapa, the full capacity of Bipole III may not be required.

4.6.0 CARBON FOOTPRINT

4.6.1 Energy Conservation in Manitoba

Energy conservation measures by MH's customers are the most cost-effective for ratepayers when they displace thermal generation for domestic consumption. Because MH's system does not allow large seasonal or year-to-year energy transfers, conservation has a comparatively low financial value whenever MH's annual hydraulic generation is above average. In below-average flow years it can increase the availability of clean energy for export sales.

However, within the MISO marketplace, MH's hydroelectric energy has not been provided carbon premiums. MH's clean energy may well displace natural gas generation. Natural gas generation carries a lower CO_2 footprint than coal generation.

4.6.2 Demand Side Management (DSM)

DSM has generally been considered a cost-effective means of achieving energy conservation. High export prices prior to 2009/10 provided MH with a net gain on most industrial DSM measures. However, at current market prices many DSM initiatives may not be favourable to MH's bottom line. An unexpected fallout from the economic downturn sees MH unable to sell all of its surplus hydraulic energy to the limits of generation and transmission tie-line capacities even at prices that cover only water rentals and transmission charges. With 12 out of the last 15 years being relatively high-flow years, MH's acquisition of DSM energy may at times have resulted in spilling excess hydraulic capacity.

4.6.3 CO_2 Emissions

MH currently anticipates that thermal generation will be limited to 200 to 400 GWh/yr and that imports will reflect about a 50:50 split between coal and natural gas generation. Other than in drought years, this picture seems realistic. The CO_2 emissions on a combined basis (thermal and imports) are now forecast to be at least 1.3 million tonnes/year.

In drought years the CO_2 emissions could be much higher. 2003/04 saw an emission level of 9.5 million tonnes of CO_2. Most of the imports in that year apparently came from coal-fired generation, which was the lowest cost off-peak supply.

MH takes the position that responsibility for emissions rests with the generator, as MH should receive credit for the reduction of indirect emissions. As such, and on a net basis, MH's exports should result in a CO_2 reduction of about 4.5 million tonnes/year. There appears to be a counterposition that has been advanced by the Western Climate Coalition (WCC), one that would provide "ownership" of emissions credit to the utility purchasing the energy. This is consistent with the concept of ownership of clean energy credits.

4.7.0 INTERVENER POSITIONS

4.7.1 CAC/MSOS

CAC/MSOS agreed that the PUB is correct to be concerned about MH's proposed development plan, as it is yet untested. The financial impact of new generation and transmission resource development on domestic rates as illustrated in IFF09-1 is of concern to CAC/MSOS.

CAC/MSOS is uneasy about the capital cost escalations associated with the major projects envisioned in MH's "decade of investment" and is looking to achieve cost impact reductions. Ultimately, CAC/MSOS took the position that MH's development plan with respect to building for export will be subject to a full review and testing and will not proceed unless the benefits can be clearly demonstrated and substantiated in a forthcoming and promised NFAAT hearing. CAC/MSOS submitted that it is confident such a review will be held, be thorough, and will adequately address the risks involved.

4.7.2 MIPUG

In general, MIPUG was supportive of MH's Recommended Development Plan and accepting of the rate implications as forecast by MH. MIPUG submitted that the recommended development scenario advanced by MH under its PRP appears to mitigate the risks associated with the financial impacts of a drought. MIPUG viewed this conclusion, provided by KPMG, as being both credible and supportive of MH's continued planning toward its planned development sequence.

MIPUG further submitted that the degree of capital investment which is required will cause the relevance of the debt-to-equity ratio to be diminished and will have the negative effect of driving a requirement for materially higher equity levels than needed. Further, since MH's retained earnings and equity are not in the form of cash and are largely intangible, they are not available to mitigate the financial adversity of a severe drought. MIPUG submitted that in the next GRA, in light of this development, the PUB should move to investigate and implement a more developed form of financial reserve target for MH.

MIPUG's assessment of the preferred and alternative development scenarios is that they do not lead to materially different rate increase outcomes for domestic ratepayers over the long term, in accordance with MH's IFF period. MIPUG therefore submitted that PUB can be satisfied that the rates being sought in the test years are sufficient regardless of the ultimate plan selected.

MIPUG's experts Messrs. Bowman and McLaren also concluded that the PRP, with the preferred development sequence, is credible enough and would deliver enough possible benefits that MH should continue to protect the option to pursue it. In order for a final decision to be made, MIPUG supports a review and testing of the merits of all reasonable alternative development scenarios by an independent body, be it the PUB or another hearing body, as long as the process is open and transparent and permits full participation by interested parties and leads to independent conclusions.

4.7.3 RCM/TREE

While RCM/TREE offered no commentary on MH's short-term planning and supported the rate increases requested in the test period, it raised concerns over the risk report information available in the hearing process respecting long term planning and risks faced by MH.

RCM/TREE did not offer a specific perspective on the factors affecting future costs and revenues faced by MH under the development scenarios which were examined in the GRA process. They commented that these questions ought to be the subject of a proper risk review in a future hearing into the need for and alternatives to (NFAAT) the portfolio of projects, and ought to have been applied earlier in the planning process. In the view of RCM/TREE, confidentiality claims prevented a proper analysis.

Finally and as recommended by Mr. Wallach, RCM/TREE sought a much broader review of potential development scenarios, with such a review to take into account reliance on increased wind and DSM resources.

Mr. Wallach also opined that risk associated with drought is increased by virtue of MH's preferred development plan. A way to mitigate the risk, he offered, is to diversify the sources of power generation. However, RCM/TREE acknowledged KPMG's conclusion that transmission enhancement achieved via new long-term contracts reduced risk and offered that perhaps the complete dependency on hydroelectric resources and new transmission access would act as a counterbalance to greater risk.

4.8.0 BOARD FINDINGS

MH's power resource plans impact capital expenditures, which in turn impact consumer rates through finance expenses and depreciation and amortization expenses related to those capital expenditures.

The Board is not satisfied that MH has explored all reasonable power resource scenarios, including:

- Domestic customers being the focus, with limited exports;
- Domestic customers and export customers as equal embedded cost participants; and
- Exports as an independent profit centre, separate from domestic customers revenues and costs.

In particular the Board finds it troubling that MH has not explored, in any depth, a Combined Cycle Combustion Turbine (CCCT) natural gas thermal generation supply alternative to new major hydraulic generation and transmission projects.

MH chose to compare its Keeyask and Conawapa hydraulic options with a Single Cycle Combustion Turbine (SCCT) natural gas plant. Single cycle gas plants are not nearly as cost efficient as combined cycle natural gas plants (CCCT).

The failure of MH to flesh out the potential diversification of supply through the construction of a CCCT generating plant, as part of MH's future development sequence, ignores the current competitive position of CCCT generation in the MISO Market.

In light of the collapse of MISO spot market energy prices, MH should have carried out and disclosed a due-diligence assessment of its business plan. This should now be carried out, whether or not an NFAAT approval process that considers the CCCT alternative, is established by the Province.

In the Board's view, MH's apparent decision to proceed with the Keeyask G.S. to serve the 125 MW (NSP)/250 MW (MP)/100 MW (WPS) additional export sales instead of proceeding with Conawapa G.S. is a significant departure from both MH's Recommended Development Plan and MH's Alternative Development Sequence. It would appear to contemplate a power resource scenario that leaves out Conawapa G.S. if the additional 400 MW (WPS) contract is not achieved. As such, the full benefits of Bipole III would not be realized. With the considerable escalation of project costs – each successive update of MH's capital expenditure plans has shown material increases in the forecast cost of expansion - the Board is looking for MH to justify, and an independent tribunal to comprehensively review, each of the projects on a net present value basis within an NFAAT (while the Board Chairman would prefer Bipole III be included in the NFAAT review, the Vice-Chair would not).

While 100% of Keeyask G.S. capacity under maximum flow conditions requires additional transmission capacity, the Board is of the view that the Keeyask G.S. would still be able to operate at about 80% of maximum capacity even if Bipole III were delayed. A net present value analysis of natural gas (CCCT) generation for reliability purposes should explore the full range of possibilities for deferral of Bipole III.

When Drs. Kubursi and Magee suggested to the Board that MH should be focused on 'least cost scenarios' in exploring future power resource and export initiatives, it suggests that with current natural gas prices and low MISO Market prices, a natural gas (CCCT) generation scenario should be examined.

The Board is 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, future environmental protection costs can be expected to flow to MH's domestic customers via higher rates.

A further concern of the Board is that MH may be routinely selling hydraulic energy and purchasing mostly coal-generated energy in the same year. When MH accesses the

MISO market for the lowest-price energy, coal energy would, in off-peak periods, be the most likely source. This effectively negates the benefits of restricting the operation of the Brandon Coal Plant. The Board understands that under the WCC initiatives, the coal-fired imports would be assigned to MH. In these circumstances a natural gas CCCT could in effect, reduce, MH's GHG footprint.

Without a fully tested business case, through a detailed NFAAT proceeding, the Board will not support rate increases for recovery of future expenses related to MH's untested, and as of yet unapproved, capital plans.

5.0.0 CAPITAL EXPENDITURES

5.1.0 CONTEXT

MH's capital expenditures result in costs that must be paid through domestic consumer rates and/or export revenues. MH filed its Capital Expenditure Forecast (CEF) with the Board in support of MH's proposed rate increases. MH's major generation and transmission project capital costs stood at $16.0B in CEF-08 with essentially the same listing of specific projects as now contained in MH's proposed development plan. The budgets have now grown to an aggregate of $22.5B (and possibly to $23.5B).

The primary contributors to a $7.5B increase from CEF08 are:

- Bipole III – up $0.95B to $3.2B (40% increase / possibly 80% if Bipole III cost goes to $4.0B);
- Keeyask G.S. – up $1.94B to $5.64B (53% increase);
- Conawapa G.S. – up $2.79B to $7.77B (56% increase); and
- Pointe du Bois – up $1.1B to $2.94B (120% increase).

Bipole III with an east side alignment was proposed initially in 1990 to accommodate a 1,000 MW sale to Ontario at a cost of $1.7B. After that deal fell apart, MH explored HVDC wires only (no converters) on the east side to reduce Bipole I and II failure impacts from events such as occurred in October 1996.

However in CEF04, Conawapa G.S. resurfaced, along with a need for a Bipole III containing both wires and converters. In CEF07 a routing west of Lake Winnipeg was adopted with a budget of $2.25 billion. This budget remained unchanged for three years until March 2011, when a revised budget of $3.2 billion was issued as approved by MH.

There still remains doubt as to whether the Bipole III budget, with its current cost estimate of $3.2 billion, will prove accurate, or whether the forecast costs will again increase, to, say, $3.9 billion or $4.1 billion, or even higher.

The cost implications associated with the building and operating of Bipole III could be upwards of 3¢/kWh (maybe as high as 4.5¢/kWh) for moving 11,500 GWh of additional energy from Northern Manitoba to the south. These costs would be realized as Bipole III is constructed and would be recorded on MH's annual Operating Statement immediately upon Bipole III coming into service. In today's market conditions, it seems most probable that it would be domestic customers rather than MH's export customers that would pay for these costs. This would likely result in domestic rates for all customer classes materially increasing if or when Bipole III comes into service.

When MH was negotiating with NSP prior to 2009 to extend its contracts beyond 2015 and both MP and WPS were to sign new sales contracts extending beyond 2020, the average output cost of 4,400 GWh of new energy generated by a $3.7B Keeyask G.S. was estimated to be in the range of 7¢ to 8¢/kWh. Subsequently, in MH's latest forecasts, Keeyask G.S's projected cost increased by 25% in CEF10 and another 18% in CEF11. This constitutes an aggregate increase of 50%, which translates into a unit cost for produced energy of 10¢/kWh.

Similarly, in 2009 the average projected cost of 7,700 GWh of average new energy coming from a $5.0B Conawapa G.S. was 7¢/kWh. Subsequently, with the projected cost of building Conawapa having increased by 25% in CEF 10 and by another 25% in CEF11 (an aggregate increase of 56%), the cost of produced power from the proposed new plant has risen to about 9-10¢/kWh.

There were indications raised in the current hearing that the Term Sheet negotiations carried out in 2007/08 provided for contract prices associated with the expected NSP/WPS/MP sales that have not been increased in recent negotiations to reflect the increasing capital costs. Accordingly, those cost increases will not be recovered through higher export prices.

It appears to this Board that future project cost escalations between today's date and the in-service dates for the new facilities would similarly not be recovered by increases in average export contract prices. The Board faces the dilemma that without access to the export contracts, it has to rely on publicly available information. This information suggests that averaging the pricing of firm sales and opportunity sales will result in unit sales prices of no more than 6-7¢/kWh, reflecting both fixed prices and variable market-based prices. Such pricing would not recover the current estimated cost of producing power at either Keeyask G.S. or Conawapa G.S.

MH does not agree with the use of the initial in-service annual revenue requirement to define current rate impacts and suggests that longer term (50-100 year) levellized costs should be employed in determining the impact on domestic rates. This approach, if adopted by MH and PUB, has two implications:

- It would assign all new project costs to domestic customers; and
- It would result in the new export sale contracts enjoying the longer-term average prices despite the fact that the actual contract terms currently only extend to 10-15 years.

In short, it appears that MH prefers to consider revenue flows from export contracts linked to the construction and operation of new hydro-electric generating stations to be considered "incremental" revenue that is not subject to the full costing that usually applies to the consideration of new plants.

The Board is of the view that before proceeding with the construction of any of the new hydro-electric plants, and following an NFAAT, the Board should determine the potential rate impacts for domestic Manitoba customers with respect to these projects.

Otherwise, there is a genuine risk that domestic rates will rise sharply as the new generation and transmission assets currently planned come into service.

With respect to Bipole III, the views of the Chairman and Vice Chair differ. The Chairman is of the view that the same reasoning set out in the preceding paragraph applies to Bipole III. The Vice Chair accepts that Bipole III is required for reliability reasons at this point in time and that a delay until an NFAAT has been completed is not warranted.

5.2.0 CAPITAL FORECAST HISTORY OF MAJOR GENERATION AND TRANSMISSION PROJECTS

MH's capital estimates for major generation and transmission projects have shown significant periodic upward adjustments. This is illustrated in the following Table.

COST ADJUSTMENTS FOR MAJOR CAPITAL PROJECTS

Progression of Project Costs in $ M								
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF Mar/11
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275	1,275
Wuskwatim Transmission		199	200	257	320	316	316	291
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591	1,566
Herblet Lake Transmission	56	55	54	54	95	93	93	75
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248	2,248[1]
Riel G.S.	96	101	103	103	105	268	268	268
Kelsey G.S.	121	121	166	166	184	190	190	302
Kettle G.S.		61	61	61	61	76	76	166
Pointe du Bois G.S.	421	288	692	834	818	818	318	398[2]
Pointe du Bois Transmission					83	86	86	86
Slave Falls G.S.				179	192	198	198	223
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325	7,771
Keeyask G.S.						3,700	4,592	5,637
500 KV Dorsey U.S. Border						205	205	205
Additional N-S Transmission								313
Total						16,034	17,781	20,524

[1] MH's currently approved Bipole III estimate stands at $3.2B.

[2] MH's latest Pointe du Bois estimate includes:

Spillway	$ 398M	(2015/16 in-service)
Power House	$1538M	(2030/31 in-service)
Total	$1936M	

In total, the estimated major generation costs have risen from $16B in CEF-08 to $20.5B in the March 2011 CEF and more recently to approximately $22.5B.

5.3.0 CAPITAL COST INCREASES FOR EXPORT-DRIVEN PROJECTS

5.3.1 Overview

MH's Business Plan seeks to achieve about 40% of foreseeable future total corporate revenues from the export market. To do this, it is deemed essential by MH that the following projects proceed within the next 10-15 years:

- Bipole III (circa 2018/19)
- Keeyask G.S. (circa 2018/19)
- Conawapa G.S. (circa 2023/24)

MH's Recommended Development Plan was first defined in the 2008/09 Power Resource Plan and in CEF-08 focused on these 3 projects. Since then the costs have been adjusted upward as follows:

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

[1] Not an officially endorsed estimate, but based on internal MH calculations.

5.3.2 Bipole III

Bipole III was originally identified (circa 1990) as a component of the Conawapa G.S. project to support a 1,000 MW major energy sale to Ontario Hydro. The intended route for Bipole III at that time was down the east side of Lake Winnipeg.

The project estimate was $1.7B for transmission lines and converter stations. When in the early 1990's energy demand and energy prices fell short of earlier expectations, Ontario Hydro elected to withdraw from the sales agreement and pay compensation for costs (access roads, cofferdams, etc.) that MH had incurred relative to the generating station. No decision had been made on the specific east side alignment for Bipole III.

In September 1996 a severe wind event (tornado or wind shear) destroyed towers on both Bipoles I and II. Given a favourable low demand time of year and a quick response by MH there was no "brown-out" and the revenue consequences were relatively low. However, the event did change MH's view of the reliability of and risk with respect to Bipoles I and II. In the subsequent years MH looked to achieve additional transmission capabilities that would reduce the risk of brown-outs.

In CEF03 and CEF04 MH proposed building HVDC transmission lines without converters on the east side of Lake Winnipeg. The lines were intended to address reliability concerns about a Bipole I or II failure and to reduce HVDC line losses. Project costs were estimated at $350 to $400M.

At the time of that proposal, concerns were raised with respect to the environmental and public acceptability of an east side alignment for Bipole III. Subsequently, MH began to explore the costs and implications of a Bipole III alignment west of Lake Winnipeg. The alternative of another HVDC line through the Interlake paralleling Bipoles I and II was rejected as possibly compounding the risks to existing facilities.

CEF-05 and CEF-06 both carried a $1.88B cost estimate for an east side routing. CEF-07 raised the costs to $2.248B to reflect a longer west-side location. MH did not revise the Bipole III cost estimate in CEF-08 or CEF-09 even though MH raised the capital cost estimates for Keeyask G.S. by $0.9B and for Conawapa G.S. by $1.3B. At the time MH cited 'sticker shock' as one of the reasons for the 25% jump in costs.

A September 2009 capital cost estimate for Bipole III surfaced in Q4 of 2010/11. It indicated that costs had risen to $3.9 B. This Capital Justification Addendum (CJA) estimate was initially deemed to have no official status. It was subsequently found to have been signed by MH vice-presidents on September 10, 2009. Reportedly, the CJA was not put forward to MH's Board.

In the spring of 2011, a new summer 2010 capital cost estimate of $4.1B was leaked to the media. At this hearing, MH denied that that estimate reflected the new projected capital cost. In January 2011 MH sought an independent review of Bipole III costs by Rashwan and Associates. Mr. Rashwan had previously been an employee of MH. The summer 2010 estimate was provided to him for his review. Rashwan (et al) reviewed the design concept and costs for the converter station and collector lines but not the HVDC transmission line. They concluded that MH could reduce costs by the elimination of contingencies that were to cover synchronous converters and the usually employed escalation costs. Incorporating these changes, MH provided a revised Capital Justification Addendum with a $3.2B total cost for Bipole III. This addendum was also signed by the vice-presidents of the same division within MH.

5.3.3 Keeyask G.S.

In the 2004/05 PRP MH's cost estimate for Keeyask G.S. was $1.7B. This cost was subsequently increased twice. The first increase was from CEF-08 at $3.7B to CEF-09 at $4.59B, representing a 25% increase. The second increase was from CEF-09 at $4.59B to CEF-10 at $5.64B. This represents a further 18% increase, for a total increase over the original estimate of 47.5%.

MH cited material supply and labour shortages (sometimes referred to as "sticker shock") as the primary cause of the pre-CEF-09 cost escalation. No specific causes have been identified for the most recent increases.

5.3.4 Conawapa G.S.

When (circa 1990) MH looked to building Conawapa G.S. in order to provide electricity to Ontario Hydro, the estimated construction cost for Conawapa G.S. was $3.8B. This cost was similar to the cost of $4.0B reflected in CEF-04.

CEF-05 and CEF-06 escalated the projected cost to \$4.5B and \$5.0B respectively. MH did not escalate the cost further in either CEF-07 or CEF-08. However, CEF-09 saw a 25% escalation from CEF-08 to \$6.3B and CEF-10 saw a further 25% increase from CEF-09 to \$7.8B. This represents a total increase of 56% over the CEF-06 estimate. MH has not provided any specific details to support these large increases.

5.3.5 Wuskwatim G.S. and Transmission

The CEC hearings circa-2004 on the Wuskwatim generation and transmission project dealt with a capital cost estimate of \$900M. At the planned average output of 1,500 GWh per year, the electricity cost would have been approximately 6¢/kWh after the in-service date. As the project nears completion in 2011/12, the capital cost has risen to about \$1.6B. The impact of this increase is that the cost to generate electricity will have risen to approximately 9¢/kWh when the Wuskwatim facilities come in service.

5.3.6 Pointe du Bois G.S. and Transmission

After MH purchased Winnipeg Hydro in 2001, it was anticipated that the Pointe du Bois G.S. could be upgraded circa 2011 at a cost of about \$400M. The upgrade would have resulted in a modest increase in capacity and energy output. In the 2010/11 PRP, MH is looking at about \$2.0B for a total rebuild of the power house and spillway by 2030/31. This would provide a 50% increase in capacity and an additional 150 GWh/yr of energy output for a total average output of 800 GWh/yr, but at cost increase of 300% compared to the 2003 estimate.

Assuming the existing Pointe du Bois G.S. would otherwise be decommissioned and written off, the average initial year new plant output cost at in-service would be 20-25¢/kWh. It should be noted that the spillway-related costs of \$0.5B are essentially unavoidable even if the powerhouse were to be decommissioned.

5.3.7 Other Hydraulic Generation Upgrades or Retrofits

MH has plans to undertake the following additional capital projects:

- Kelsey G.S. Rerunning, with a capital cost increase of more than 50% in CEF Mar/2011 relative to CEF08. Limited capacity and energy gains are expected.

- Slave Falls Upgrade with a capital cost increase of only 12% from CEF08. No capacity or energy gains have been identified.

5.3.8 Wind Energy Purchases

MH currently purchases the entire output from the 100 MW St. Leon and 138MW St. Joseph wind farms. The contracts call for MH to buy the entire output from both farms at undisclosed but defined prices which are significantly higher than the current average price of MH's opportunity export sales.

5.3.9 Transmission Additions

MH has identified a need for the following additional transmission projects:

- Additional north-south transmission to supplement Bipole III operations at an initially estimated $313M.

- A 500KV Dorsey to US border intertie initially estimated at $205M in CEF08, a cost that has not changed through March/2011.

5.4.0 REVENUE REQUIREMENTS TO SUPPORT EXPORT-DRIVEN PROJECTS

When a generating station (or a unit of a generating station) comes into service, MH no longer capitalizes the related costs. Rather, the costs, including financing charges, operating and maintenance costs and depreciation expenses are charged through to consumers by way of MH's Operating Statement. MH then proposes rates to recover the costs as set out in the Operating Statement.

The Board calculates the likely annual in-service costs for the new major capital projects that that will be recorded on MH's Operating Statement to be as follows:

- Keeyask - approximately $500 million – in 2018/19;
- Conawapa - approximately $700 million – in 2024/25;
- Bipole III Transmission - approximately $300 million – in 2016/19.

While MH correctly points out that their annual costs will decrease over time, such a decrease is usually very gradual.

To the extent MH's real costs with respect to these projects are not recovered from export customers, it will fall to Manitobans to bear financial responsibility through reduced annual net income of MH (and reduced overall retained earnings) and increased electricity rates for Manitobans.

The Board does not accept that "levellized costs" should be used to assess cost impacts when major capital projects come into service. The Board understands that MH uses levellized costing in its long range planning. However, the Board must have regard to how costs are paid for by consumers. Consumer rates are not based on levellized costs – they are based on actual and real costs as reflected in MH's Operating Statement.

5.5.0 INTERVENER POSITIONS

In general, the Interveners in this hearing, citing the Board's restricted jurisdiction over approval of MH's capital expenditures, did not challenge the validity of MH's estimates for the cost of major generation and transmission projects. Despite the very substantial cost projection increases since 2004/05, none of the Interveners took issue with MH's calculation of potential additional revenue requirements over the next 20 years.

5.5.1 CAC/MSOS

CAC/MSOS took issue with MH's apparent lack of foresight and unwillingness to address in a timely fashion the substantial escalation of Bipole III capital costs.

CAC/MSOS recommended that in order to assist the PUB in understanding the risks associated with MH's planned capital projects and the extent to which these risks are addressed through contingency allowances in MH's capital cost estimates, it would be useful if the PUB required, as part of MH's initial filing in a GRA, the capital project justification forms established for each project with costs in excess of $100 million dollars. This would ensure that the Board is fully informed regarding the risks associated with a particular capital project and any allowances that MH has incorporated in the project's costs to address these risks.

However, citing the Board's lack of jurisdiction, CAC/MSOS did not specifically address the increased capital cost of either Keeyask G.S. or Conawapa G.S. and the potential rate implications.

5.5.2 MIPUG

Although MIPUG did inquire into the nature of the capital cost increases, MIPUG did not specifically explore the issue of the substantial capital cost escalation and the impact of that escalation on MH's customer rates.

5.5.3 RCM/TREE

RCM/TREE did not specifically explore the issue of capital cost escalations and the potential cost implications for domestic customers. RCM/TREE continued to support maximizing export sales through expanded DSM, inverted rates and discouraging domestic electricity use for home heating.

5.6.0 BOARD FINDINGS

5.6.1 Rate Implications of the Recommended Development Plan

The Board is of the view that with the substantial capital cost escalations currently known, MH's IFF09-1 portrayal of domestic rate implications is no longer valid. Further cost escalations cannot be ruled out, and given the current state of the export market, there are no foreseeable offsetting net export revenue gains.

It would appear obvious that Bipole III costing $3.2B instead of $2.3B would require an additional rate increase in 2019, and Bipole III costing $4.0B instead of $2.3B would require an even larger rate increase in 2019.

Similarly, the Board is of the view that Keeyask costing $5.64B instead of $4.59B would require an additional rate increase in 2019, and that Conawapa costing $7.77B instead of $6.33B would require a substantial further rate increase in 2026.

5.6.2 Capital Cost Escalation

The Board views, with considerable concern, MH's lack of a defined approach to updating major project costs. Delaying the use of updated cost estimates for administrative process reasons reflects poorly on the validity of MH's recommendations for future power resource developments.

Outdated estimates can make potential export contracts look overly favourable and subsequently have the potential to lead to higher domestic rates than envisioned. Furthermore, one would not expect to see commitments entered into with respect to major projects and large export contracts when the capital budget for the underlying projects has not been changed for three or four Capital Expenditures Forecasts to reflect cost increases.

As the Board understands it, when MH initiates export sales negotiations that require new generation and transmission facilities, the price of capacity and energy is a major component of the term sheet conditions. For MH and others to suggest that the project cost and subsequent escalations are not material to export contract prices would lead to the conclusion that all cost escalations are to be paid for by Manitoba ratepayers. The public record with respect to the project cost escalations discussed in this Order shows that the rate risk to ratepayers is high when capital cost updates are deferred.

5.6.3 Capital Cost Recovery from Export Sales

The Board is unaware of any explicit MH policies or procedures to ensure adequate capital cost recovery on facilities built or advanced for export purposes. If two- or three-year old capital estimates are used as the basis for export price negotiations, there is a significant potential for revenues and costs to be misaligned.

MH and its consultants have demonstrated reluctance to the premise that MH's in-service unit output costs from new generation and transmission projects should be fully recovered from the average price of energy in any firm energy export contract. In the Board's view, a failure to achieve full recovery amounts to an acceptance of inevitable increases in domestic rates.

The Board cannot understand how a portion of capital or finance costs related to a project can reasonably be deferred to allow for lower domestic rates in the absence of export pricing sufficient to fund the capital expenditures.

MH's position that Bipole III costs should entirely be paid for by domestic customers is not consistent with the reality that the building of Conawapa G.S., for which Bipole III would be built, in the time frame contemplated is in large part to satisfy export commitments. In the Board's view, it also ignores the reliability benefits that are extended to existing and future export contracts and ongoing market sales.

Prior to the construction of the Wuskwatim Generating Station, which comes into service this year, the last major generating station constructed by MH was Limestone G.S. some twenty years ago. Limestone G.S. has, with hindsight, turned out to be an excellent investment for Manitoba. However, the "Business Model" used with regards to Limestone may be a dangerous business model to use with regards to Keeyask G.S., Conawapa G.S. and the Bipole III transmission line.

When Limestone was constructed earlier than needed for Manitoba's domestic load, the output from Limestone was to be exported on the "spot market". Unfortunately, the cost of producing electricity from Limestone G.S. when it came into service in 1992 was approximately 2 ½ to 3¢/kWh at a time when the export market was returning less than that, so MH suffered a loss in its Net Income. Limestone only became a wise investment over time, as inflationary pressures and an increasing unregulated wholesale electricity market drove up prices – MH holds that the same result can be expected with the construction of Keeyask G.S. and Conawapa G.S., although many factors have changed over the past two decades that make that assumption questionable.

From a rate setting perspective, once a generating station (or any unit of a generating station) is placed in service, all of the fixed costs can no longer be capitalized and are added to the rate base to be recovered from domestic customers or from export sales. It is by the same rate setting principles that when Wuskwatim G.S. comes into service, MH's Operating Statement will record an additional $153 million per year of costs associated with producing about 1,500 GWh of energy per year. The unit cost of energy approximates 10¢/kWh.

Because Wuskwatim's output is not immediately needed for Manitoba load, its output is to be sold on the export market. Presently there is no fixed-price export contract for Wuskwatim G.S.'s output, which means that such output will be sold on the 'spot market' – a market currently returning prices approximating 3¢/kWh during peak hours and less than half of that amount during off-peak hours.

Because the $153 million per year of costs are real, and the spot export revenues will only cover less than a third of those costs, it falls to domestic Manitoba customers to cover the financial losses flowing from the operation of Wuskwatim G.S. Those losses will result in reduced Retained Earnings, higher consumer rates, or both.

While the Board acknowledges that the in-service costs will gradually decline over the years the generating station is in service, as the financing costs will fall as the principal balance of the debt assumed declines (and the annual amortization of the initial capital cost represents non-cash expenditures), such cost decreases are very gradual.

Manitobans will be responsible for any losses incurred on the reliance of the export market until the electricity is actually needed by Manitobans.

The very same accounting and regulatory principles apply to Keeyask G.S. and Conawapa G.S. With in-service unit costs of approximately 10¢/kWh for generation and export prices returning considerably less than that, Manitobans are to bear responsibility for the losses.

As for the Bipole III transmission costs, which will approximate 3¢/kWh for every kWh of electricity transported, without having access to the export contracts the question is whether all or some of the costs will be met by net profit from export contracts or will have to be entirely paid for by Manitoba customers.

MH's Business Plan of 'building for exports' contains serious, real and significant risks and costs for domestic Manitoba customers. The current Business Plan can be contrasted with MH's pre-2000 Business Plan when it proposed and planned to construct a 'merchant plant' (i.e., a plant built to serve the export market) to export the output to a counterparty by way of a fixed-price long term contract.

Because of the near-decade of lead time required to build a large hydraulic generating station, beginning in the early 1990s MH was considering building the Conawapa G.S. as a merchant plant and selling 100% of the plant's output to Ontario Hydro. MH's Business Plan at the time incorporated provisions whereby Ontario Hydro's payments would exceed the costs incurred by MH to construct and operate Conawapa, such that there was an expected net benefit (profit) to MH over the entire term of the export contract.

While this Board's jurisdiction does not extend to the approval of MH's capital expenditures, this Board does have jurisdiction over the approval of MH's rates in which MH seeks to recover the financing, operating and amortization expenses directly attributable to MH's capital expenditures. MH has taken the position that it is important that MH maintain an adequate level of retained earnings and that rates be raised gradually even during periods of exceptional water flows. It also stated that an adequate level of retained earnings provides funding for capital investments, which in turn reduces the need for borrowing and reduces the financing costs that ultimately must be recovered from ratepayers.

Against the backdrop of different types of business plans, together with the apparently skyrocketing capital costs of Keeyask G.S., Conawapa G.S. and Bipole III, together with a depressed export market and Manitoba consumers being held financially responsible for any losses, the Board is of the view that MH's capital projects require careful and detailed scrutiny. The Chairman is of the view that this scrutiny should apply to both generation and transmission facilities. In the Vice Chair's view, while scrutiny is required for all projects whose primary current purpose is to meet export demand, Bipole III should not be delayed as it is required for reliability purposes.

Scrutiny of MH's projects has, in essence, been promised by MH when it produced confirmation from the Province of Manitoba that an NFAAT hearing similar to the one held for Conawapa G.S. in the early 1990s and Wuskwatim G.S. in the early 2000s is to occur.

Due to the hundreds of millions of dollars the Province derives from MH, the risks that will be borne by MH's domestic customers, and due to the economic and financial factors to be tested, such an NFAAT ought to be conducted by an independent tribunal with considerable expertise in the subject issues.

6.0.0 OPERATING RESULTS

6.1.0 OVERVIEW

In support of its GRA Application, MH filed its Integrated Financial Forecast (IFF) 09-1 for its electric operations, as well as its Capital Expenditure Forecast (CEF) CEF 09-1, both covering fiscal year periods 2009/10 to 2019/20. Updated forecasts (IFF 10-1, IFF 10-2 and CEF 10) were also filed over the course of the hearing. IFFs and CEFs are prepared to provide an indication of the long-term financial direction and plans of the Corporation, and are based on numerous assumptions.

MH's actual results for fiscal year 2009/10 and its updated forecast for fiscal year 2010/11 reports or forecasts that accumulated net income for the fiscal years from 2009/10 up 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 forms the basis of the Application before the Board.

The projected improvement in accumulated net income and retained earnings (retained earnings represent MH's "equity" or invested capital) was attributed primarily to lower than forecast depreciation, finance expenses and fuel & power purchase costs. The forecast results also represent 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. The following table provides an overview of MH's actual and forecast revenues and expenses.

Manitoba Hydro's Revenues and Expenses, 2008-2012

Statement of Operations & Retained Earnings ($ Millions)	Actual			IFF10-1		
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	
Debt:Equity Ratio	76:24	75:25	74:26	74:26	74:26	

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 $62 million.

MH's financial position since the 2008 GRA is projected by MH to have improved by approximately $253 million for the fiscal years 2007/08 up to and including 2011/12. A major contribution to this improved financial position has been Board-approved rate increases which have generated over $788 million in accumulated additional revenue. Since 2004/05, over $950 million in additional revenue has been realized by MH from Board-approved domestic rate increases (this represents over one-third of MH's retained earnings).

6.2.0 FORECAST UPDATE

Two forecast updates were provided during this hearing. IFF10-1 reflected a reduction in the near term for interest rates, but the most significant change was material increases in the capital costs for both the Conawapa G.S. and Keeyask G.S. The capital cost estimate of Keeyask was increased from $4.6 billion to $5.6 billion. For Conawapa G.S., the estimated cost of construction increased from $6.3 billion to $7.7 billion. On an overall basis, the capital costs for MH's major generation and transmission projects have increased in excess of $2.6 billion dollars in IFF10-1 compared to IFF09-1.

This second update, set out in IFF10-2, reflects increases to the projected capital cost of Bipole III. The capital cost projection for Bipole III forecast in IFF09-1 and IFF10-1 was $2.2 billion. The forecast was revised to $3.2 billion over the course of this hearing, an increase of $1 billion from previous forecasts. Although other forecasts prepared internally by MH saw the cost exceeding $4 billion, MH adopted the lower estimate. The implications of this $1 billion increase capital costs were reflected in IFF 10–2. The following chart provides a comparison of the net income forecast during the outlook period in IFF09-1 with the updates provided as follows:

NET INCOME FORECAST CHANGES – IFF09-1 TO IFF10-2

Net Income- Electric ($ Millions)				
Year Ending March 31	**MH09**	**MH10-1**	**MH10-2**	**Comparison MH10-2 vs. MH09**
2010	$121	$163	$163	$42
2011	$78	$149	$149	$71
2012	$87	$125	$125	$38
2013	$72	$120	$121	$49
2014	$125	$184	$187	$62
2015	$113	$142	$145	$32
2016	$248	$217	$219	($29)
2017	$263	$267	$267	$4
2018	$235	$273	$218	($17)
2019	$244	$225	$111	($133)
2020	$276	$292	$187	($89)
2021	$299	$109	($1)	($300)
2022	$439	$351	$233	($206)
2023	$544	$443	$319	($225)
2024	$732	$512	$382	($350)
2025	$791	$631	$493	($298)
2026	$911	$597	$449	($462)
2027	$1,005	$692	$538	($467)
2028	$1,116	$796	$637	($479)
2029	$1,224	$906	$741	($483)
Total	**$8,923**	**$7,194**	**$5,683**	**($3,240)**

The successive increases in capital costs have resulted in an increase in long-term debt and related increase in finance expenses. Long-term debt was forecast in IFF09-1 to be $17.7 billion in 2029. The estimate was revised up to $21.2 billion in 2029 in IFF 10–1 and was further increased to $23.0 billion in IFF 10–2. The capital costs and the respective debt to support the increased costs result in increased operating and finance costs over the outlook period. Finance expenses in 2029 were forecast to be $980 million. Since then, they have increased to $1.2 billion in IFF10-1 and further increased to $1.4 billion in IFF10-2. Between IFF09-1 and IFF10, finance expenses in 2029 (by which time all major generation and transmission projects will have come into service) have increased by over $403 million annually.

The forecast increase in expenses from IFF09 to IFF10-2 has led to a reduction of forecast net income over the period from 2010/11 to 2028/29 by over $3.2 billion.

MH has established the export price assumptions used in its forecasts from independent forecasts provided by ICF and others. During this hearing, ICF presented information indicating a forecasted reduction in natural gas prices of 40% from previous forecasts due to abundant shale gas that can now be extracted through new technology. Shale gas is a source of natural gas that was previously uneconomic to extract. However, with new technologies, shale gas is now capable of being extracted in large quantities at low costs.

MH exports into the MISO market. Electricity generated from natural gas forms the basis of establishing marginal peaking prices in the MISO market 10% to 50% of the time. The balance of the time, MH’s opportunity export prices are established by the coal generation prevalent in the MISO region.

Prior export price forecasts provided by ICF were predicated on the establishment of a U.S. carbon regulatory regime, which would increase the cost of electric coal generation. No such regime has emerged to date, and ICF has revised the timing and extent of any carbon regulatory pricing in the future downward materially.

This change in perspective on natural gas pricing and a carbon regulatory regime is not reflected in the current IFFs presented at this hearing. The issues related to export pricing are discussed further in section 5.6.0 of this Order.

6.3.0 INTERVENER POSITIONS

6.3.1 CAC/MSOS

CAC/MSOS noted that the improved actual net income for 2009/10 was $164 million. This compares to only $121 million forecast in IFF09-1, which formed the basis of MH's application. Net income in IFF10-1 for 2011/12 is now forecast to be $149 million versus $78 million in IFF09-1 and $125 million versus $87 million (IFF09-1) in 2011/12. The combined forecast improvement of $109 million more than what was forecast for those years in IFF09-1 suggests that the interim rate increases granted by the Board should be reduced.

6.3.2 MIPUG

MIPUG submitted that it does not oppose final confirmation of the two interim rate orders granted by the PUB in this proceeding. MIPUG did recommend that MH be directed to do a small rebalancing of rates, on a go-forward basis from the date on which rates are finalized, among domestic rate classes in recognition of differences in revenue to cost ratios. MIPUG's experts Mr. Bowman and Mr. McLaren opined that in general terms, rate increases in the order of inflation are understandable, so long as they are merited and defensible in terms of MH's cost structure and fairly distributed across the different rate classes.

6.3.3 RCM/TREE

RCM/TREE submitted that the interim rates should be approved as the final rates, and a further 0.9% increase from the date of the final order should be allowed. RCM/TREE further submitted that the PUB should also consider an interim rate increase for 2012/13 of 3.5% subject to a hearing for the April 1st 2013 period.

RCM/TREE also sought reintroduction of an inclined rate structure, with a change in the block size to reduce the first block. RCM/TREE further sought MH to identify electric heat customers by using a methodology suggested by this Intervener, and that MH implement a larger first block structure for these customers over the winter heating period, as proposed by Mr. Chernick.

6.4.0 BOARD FINDINGS

These findings need be read in conjunction with the Board's findings on Rates as set out in section 3.0.0 of this Order.

The Board notes the marked improvement in net income in the test years from what was forecast in IFF09, which formed the basis of the Utility's application. With the finalized rate increases approved in this Order, the fiscal health of MH in the test years (2010/11 and 2011/12) has never been stronger in MH's 60-year history.

The Board notes that MH has attained its 75:25 debt-to-equity target, a target it will "slip away from" in the next several years. The Board has grave concerns with the long-term outlook reflected in IFF 10–2.

The Board notes that over the course of two successive updates to IFF09, the increase in capital costs of Keeyask, Conawapa and Bipole III and related increased debt levels now see a 'build' price tag in excess of $20 billion, with long-term debt previously forecast to be $17 billion now over $23 billion. This higher forecast debt level and higher associated carrying cost (now to reach over $1.4 billion) has eroded the forecast profitability during the forecast period by $3.2 billion.

The Board understands that MH's forecasts are used to underpin the justification for the new major generation and transmission projects. While they reflect increased capital costs, they do not reflect the downward change in export prices that has occurred since 2008. The forecasts further do not reflect a sustained strengthening of the Canadian dollar or the lower prospects for export prices given the new realities of inexpensive and abundant shale gas, which is a common feedstock for low-cost electric generation in the markets into which MH exports. Nor does the forecast reflect the potential new reality of a low- or no-carbon regime in the export markets into which MH sells its electricity.

Abundant coal with no carbon adder and abundant natural gas will have a dampening effect on export prices in the MISO market. Given that MH is a price taker in the MISO market, lower generation costs in the export markets could have a material impact on MH and its potential export revenue. Neither of these potential realities are reflected in the forecasts presented to the Board at this GRA.

The Board requested MH to provide additional IFF scenarios, to explore the impact of such circumstances on ratepayers. They were not provided, and as noted in section 5.6.0 of this Order, MH’s capital plan has not yet been tested by an NFAAT.

7.0.0 EXTRA-PROVINCIAL REVENUES

7.1.0 OVERVIEW OF SALES AND REVENUES

As can be seen from MH's IFFs, extraprovincial revenues are to constitute a significant percentage of MH's total revenues.

MH'S sales into the U.S. MISO Market and into other Canadian provinces over the last decade are summarized in the following table.

MH'S EXPORTS INTO MISO/CDN PROVINCES (GWh)

	MISO Dependable	MISO Opportunity	MISO Total	Non Merchant CDN Sales	Total Sales
2000/01	4895	4511	9406	3047	12453
2001/02	4767	5083	9850	2449	12299
2002/03	4947	2713	7660	2075	9735
2003/04	5245	507	5752	1214	6966
2004/05	5683	3218	8851	1680	10431
2005/06	4044	8879	12923	1424	14347
2006/07	3654	5877	9531	373	9904
2007/08	3921	7332	11053	682	11735
2008/09	4087	6071	10158	418	10576
2009/10	2613	6218	8831	336	9167

To supplement its own generation, MH has typically imported wind and thermally generated energy at the range of 1,500 to 3,000 GWh per year. Major exceptions were 2002/03, when the total imported was 3,800 GWh and 2003/04 when the total imported was 10,500 GWh.

With existing transmission intertie bottlenecks and constraints due to MISO capacity and hydraulic generation capacity, MH is typically limited to about 7,000 GWh/year of peak energy export sales. Except for 2008/09, the peak firm and opportunity sales have, over the last 10 years, accounted for approximately 2/3 of MH's annual exports. The remaining 1/3 were off-peak sales to the MISO market and within Canada.

During the past ten years, 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 prices were 2.5 to 3.5¢/kWh. The situation changed in 2009/10, after MH's IFF09-1 was prepared. In IFF09-1 and IFF10 MH assumed average export revenue rates as follows:

COMPARISON OF AVERAGE EXPORT REVENUE RATES
IFF09-1 VS. IFF10-2

	Actual (¢/kWh)	IFF09-1 (¢/kWh)	IFF10-2 (¢/kWh)	Difference (¢/kWh)
2006/07	5.86			
2007/08	5.64			
2008/09	4.37			
2009/10	3.93			
2010/11	3.84	4.10	3.26	- 0.84
2014/15		7.40	6.63	- 0.83
2015/16		9.09	8.11	- 0.98
2019/20		10.56	10.84	+0.28
2020/21		10.66	11.12	+ 0.46
2021/22		10.94	11.13	+ 0.19
2025/26		12.25	12.20	- 0.05
2026/27		12.64	12.58	- 0.06
2028/29		13.45	13.45	Ø

IFF09-1 export price assumptions reflect the input provided to MH by a panel of external consultants in 2008. ICF, one of the consultants on the MH panel, provided evidence at this hearing that the natural gas prices employed by ICF's forecast in 2008 would currently be about 30-40% lower, and that electricity prices in the MISO market would also be lower. However, MH did not adjust these variables from IFF09-1 to IFF10-2.

7.2.0 THERMAL GENERATION COST ASSUMPTIONS

A comparison of MH's IFF assumptions on Single Cycle Combustion Turbine (SCCT) thermal generation costs leads the Board to conclude that MH did <u>not</u> significantly reduce the energy prices in IFF10 from IFF09-1 and may have increased that price from 2021 onward.

7.3.0 MH INFLUENCE ON EXPORT/IMPORT PRICING

MH has suggested that in the broader MISO market, a substantial decline in MH's energy surplus would not be noticed and hence no shortage pricing would develop. This does not seem consistent with the 2002/03, 2003/04 and 2006/07 drought events when prices did increase significantly. MH's argument that opportunity sale prices are depressed during extended high flow periods would also suggest the opposite, namely that less energy in the market should translate into higher prices. In recent years, MH has been regularly selling off-peak energy into the MISO market at prices as low as 0.5¢/kWh.

7.4.0 EXISTING 500 MW NSP EXPORT CONTRACT

MH's existing contract with NSP calls for MH to supply and NSP to purchase 2,086 GWh in each 12-month period. This amount equates to 5x16[2] energy on an annual basis or an average of 174 GWh per month. Payment for this power is based on both an energy charge and a demand charge.

In 2010/11 it appears that MH sold 2,960 GWh of firm energy into the MISO market at an average price of 5.14¢/kWh, including NSP sales of 1,970 GWh.

[2] Power supplied for the 5 weekdays, between 6 AM and 10 PM (16 hours)

7.5.0 OTHER REVENUES/COSTS

7.5.1 Merchant Trading

MH has in the past purchased energy in the MISO market for resale into Ontario by employing committed transmission services. The Board understands that MH has or will be discontinuing this low net revenue activity.

7.5.2 Ancillary Services

With the advent of an ancillary service market in MISO, MH is anticipating a high level of activity in providing capacity support within the MISO Market. The profitability of these services is currently uncertain. MH's IFF is apparently treating this as a break-even activity.

7.5.3 Transmission Tariffs

Under the open access transmission tariff, MH receives revenue for energy flowing through Manitoba, but MH also pays for transmission which flows through other transmission systems. Overall, this is resulting in a small net revenue gain.

7.5.4 NEB/MISO/FERC/NERC Costs

MH incurs membership costs with respect to business activities in the US. These can be related to both exports and imports, even though the level of export activity typically greatly exceeds the import activities. MH contends that an equal sharing is appropriate.

7.6.0 INTERVENER POSITIONS

7.6.1 CAC/MSOS

CAC/MSOS submitted that it is concerned with the significant variance of export revenue forecasts from actual export revenues.

7.6.2 MIPUG

There were no direct challenges by MIPUG of MH export revenue pricing. Rather, MIPUG supported MH's process of determining future export market prices and the need for secrecy with respect to firm contract pricing.

7.6.3 RCM/TREE

RCM/TREE noted that all of the risk experts appeared to be using out-of-date term sheets as the basis of MH's potential exports revenue position. It also noted that rather than adopting a skeptical review approach, the risk experts accepted the positions adopted by MH in conducting the risk analyses.

It was RCM/TREE's view that there should be a transparent correlation of MH's export pricing (contract and opportunity) to energy production costs. A rate-rider to track MH's unit export revenue in excess of costs was suggested.

7.7.0 BOARD FINDINGS

Going back to Board Order 116/08, the Board had concerns that MH's export revenue pricing forecasts, provided in the preceding 2008 GRA and in the 2008 EIIR application, were overly optimistic. Those forecasts assumed high natural gas supply prices in the future (up from $10.30/GJ in 2005) and, perhaps more significantly, an early introduction of substantial CO_2 emissions pricing.

Based on current market conditions and ICF's forecasts, it is the Board's view that the potential average export sale price may be substantially below MH's IFF09-1 and IFF10 assumptions over the next decade. Faced with continuing to make off-peak sales at under 1¢/kWh on a protracted basis, and contract prices likely below 6¢/kWh until 2015, MH's prospects for average export prices appear to be in the 3 to 4¢/kWh range.

Going forward, without any CO_2 pricing and a continuation of low shale gas prices, MH must compete with off-peak coal energy at 2-3¢/kWh (or wind at possibly even lower prices) and natural gas CCCT generation in the peak periods at prices in the 5-7¢/kWh range. Even with new contract prices of 8-9¢/kWh for peak energy volumes equal to about 1/3 of MH's exportable energy, the average export prices could be dragged down to around 5¢/kWh by low opportunity sale prices.

The IFF09-1 export revenue pricing (based on advice from an external consultant panel) prepared in 2008 did not reflect the lower natural gas prices (with shale gas availability already being experienced) or the major resistance to CO_2 emissions pricing in the US. Despite the ICF testimony at this hearing, which laid out a significantly lower future natural gas price outlook for October 2010 than in February 2009 and confirmed the suggested deferral of CO_2 emission pricing, MH did not significantly alter the IFF10 export revenue assumptions from those used in IFF09-1. This places the reliability of the IFF10 forecasts into doubt.

The Board notes that MH has, to date, declined to provide any alternative IFF scenarios based on lower natural gas prices and the 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 the proposed new major generation and transmission facilities such as Keeyask, Conawapa and Bipole III.

The Board no longer considers IFF09-1 as providing a 'valid' picture of MH's financial position. If MH continues with its preferred development plans, the Board concludes ratepayers will undoubtedly pay higher future domestic rates than indicated in IFF09-1 or IFF10-2.

Without access to MH's export contracts, and given the current market conditions, the Board is not convinced that MH will achieve the export revenue assumed in the existing IFFs. IFF09-1 electricity export revenue forecasts were based on 2008 circumstances, presumably by using ICF's predicted natural gas prices at the time. These predated the advent of shale gas pricing, the collapse of the planned CO_2 emission charges regime and the economic downturn in the economy.

With ICF's revised natural gas prices being 30-40% lower (based on its revision made on Oct.20, 2010), the forecast electricity prices for CCCT generation could be significantly lower, as the fuel cost portion of those prices would decrease materially.

While MH has declined to provide an IFF based on PUB/MH/PREASK-4 export electricity pricing assumptions, MH has not refuted the proposed pricing scenario. About 65% of IFF09-1 pricing assumptions are relatively consistent with the implications of ICF's revised natural prices, when applied to CCCT generation variable prices.

In the Board's view the IFF09-1 and IFF10-2 export revenue assumptions are not reflective of the current and near term energy market. As such, the suggested progression of rate increases would be inadequate to cover MH's CEF09 Major Capital Expenditure Program. When the major project cost escalation is also considered, the insufficient revenue is substantially magnified. The Board would suggest that the cumulative rate increase requirements by 2025/26 would be significantly greater than the 57% forecast by MH, and quite possibly roughly double MH's forecast.

The Board acknowledges that MH could look to lesser rate increases by accepting lower annual net incomes, lower retained earnings and higher debt levels. However, such actions and results would negatively affect MH's financial ratio targets.

In the Board's view it is crucial that expert analysis and independent scrutiny of the major capital projects be undertaken before making any irreversible commitments, as MH has attested that it has been spending $1-2M per day on its "preferred development plan" even though that plan has yet to be tested.

8.0.0 FINANCE EXPENSES

8.1.0 INTEGRATED FINANCIAL FORECAST 2009 (IFF-09)

MH's borrowings result in its finance expense being the Utility's single largest expense item. Finance expenses were $401 million in 2009, representing over 29% of total operating expenses. They were forecast in IFF09-1 to be $417 million in 2010. Actual finance expenses decreased to $373 million in fiscal 2009/10. MH had forecast finance expenses to be $413 million in 2011 and increase to $468 million in fiscal 2012, representing 25% of annual operating expenses.

In IFF09-1, MH's typical practice is to base the forecast level of finance expenses on anticipated levels of borrowings exclusively based on 30-year fixed term debt. Such an approach does not recognize that a portion of the debt issued would be shorter-term floating debt with lower interest rates than 30-year debt. In the normal course of operations, MH issues both floating rate debt and long-term fixed rate financing. This reality was addressed in IFF10-1, whereby MH has now assumed that 20% of its forecast debt issues would be floating rate debt issues. MH has a target range of maintaining 15% to 25% of debt in floating rate instruments to minimize debt costs without undue interest rate exposure.

MH capitalizes interest on all capital projects during the construction phase until the project is in service. Based on IFF09-1, by 2029 Manitoba Hydro is forecasting to capitalize over $4.8 billion in interest costs.

As the major new generation and transmission projects commence construction, MH will be capitalizing a greater proportion of interest costs. Gross interest expense is forecast to be over $1 billion in 2018, of which $449 million or 43% will be capitalized. Once all major projects are completed, this high level of interest cost will need to be recovered through rates, supported by higher levels of revenue from the new generation capacity.

8.2.0 IFF10-2

MH provided an updated IFF10-2 which indicates the capital costs of the major generation and transmission projects have increased by $3.6 billion. Higher levels of debt, now to exceed $23.4 billion by 2026, will support this higher level of capital spending. This represents an increase in debt of over $5.4 billion from what was forecast in IFF09-1.

Based on IFF10-2, the updated forecast reflects reduced interest rates in the near term. Finance expense is forecast to grow by $411 million to over $1.5 billion by 2026 (up from $1.1 billion forecast in IFF09-1) when the last of the major new Generation and Transmission projects, Conawapa, is expected to be in-service.

Based on the updated cost estimates in IFF MH10-2, MH's debt is forecast to grow from $8.7 billion in 2011 to $22.9 billion in 2030, an increase of $14.2 billion. This is $5.2 billion higher than the debt level forecast in IFF09-1.

8.3.0 INTERVENER POSITIONS

CAC/MSOS noted that the level of finance expenses represents the largest component of expense in the forecast and is expected to grow. CAC/MSOS adopted the evidence of Mr. McCormick, which recommended that the Board reject the assumption used in IFF09-1 that all new debt issues would be long-term 30-year fixed rate debt and incorporate a forecast that recognizes a policy to maintain a range of short-term debt in determining interest rate forecasts. Incorporating a short-term debt component as a forecasting element would result in a significant interest rate reduction in the forecast. Mr. McCormick acknowledged that changes made in the forecasting methodology employed in IFF10 addressed this concern. However, the GRA, which is based on IFF09, does not reflect this change.

Mr. McCormick identified four elements which are required to adequately forecast financing expenses, including:

(a) reconsideration of the composition of fixed and floating debt;

(b) assumptions respecting interest rates;

(c) currency of the debt issue; and

(d) term to maturity of the underlying debt.

In MH's IFF10-2 there is reference to an enhancement to MH's longstanding forecasting approach of assuming all new debt is to be fixed for 30 years at 10 years plus rates. However, the 20% floating rate, argued CAC/MSOS, will still tend to bias the results. Mr. McCormick opined that he would much rather see consumers paying rates in the 2011/12 test year based on what we know today about the forecast rates, as they are much more current rates, as opposed to superseded rates. Further, noted Mr. McCormick, updated rates are indicative of significant excess interest costs being forecast in the revenue requirement. Mr. McCormick noted in his report that there is no "free money", and that excessive reliance on the certainty of long-term fixed debt comes at a material cost in terms of lost opportunity for lower debt costs.

CAC/MSOS recommended the establishment of an interest rate deferral mechanism as proposed by Mr. McCormick. The interest rate deferral account would capture the difference between forecast and actual finance costs, addressing forecast differences in interest costs. CAC/MSOS proposed that MH be advised that the extent of any corporate recoveries from the deferral account mechanism would be contingent on a determination that MH has been managing its financing costs prudently.

8.4.0 BOARD FINDINGS

MH plans on borrowing an additional $15 billion to support its development plan, thereby increasing MH's overall debt level to over $23 billion.

The Board notes that in IFF09-1, MH planned on increasing borrowings by $10 billion to over $17.7 billion. The revisions in IFF10-1 and IFF10-2 have increased the borrowing requirement by 50%. These borrowings come at a cost to MH in terms of carrying costs, a significant percentage of which is currently being capitalized.

The situation is exacerbated by continued cost escalation of the major generation and transmission projects. Capitalized interest may well be over $5 billion when all developments are complete. Once developed, the ratepayers will have to cover both higher interest carrying costs as well as higher amortization charges related to the developments, regardless of the income generated from the new assets.

As stated in Order 99/11, current ratepayers are being spared the increased finance expense in rates, yet decisions made currently will impact future ratepayers. These financing costs, which are currently being capitalized, will have to be supported by higher domestic rates when the projects come online and the capitalization of finance expense is no longer appropriate.

The Board remains concerned that interest rates at historical lows will likely increase when spending ramps up on the developments, resulting in higher than forecast levels of capitalized interest and finance expense.

The Board remains concerned with the impact of further capital cost escalations. As it now stands, annual carrying costs that will need to be covered from rates will top $1.5 billion in 2029, $400 million more per year than what was contemplated in IFF09-1.

As the cost of the major capital expenditures program escalates (as demonstrated in the recent updates which saw an increase of over $3.6 billion from the IFF 09-based estimate), the escalations will result in debt levels being increased by over $5.4 billion, and, ultimately, in higher finance costs which will have to be recovered from domestic ratepayers.

The forecast level of interest costs, when these projects are in service, has increased materially while the capacity to service these additional costs has not changed. MH negotiated much of the new contracts before the escalation in capital costs appeared. It is unlikely that the counterparties to the deals would be interested in paying any more than what has been negotiated due to an increase in the costs for MH to deliver the power.

There are no assurances that the current capital cost estimates will hold. Given the successive annual updates, the Board remains concerned that the economics related to these developments may be diminished. As such, it is important that MH be involved in an NFAAT process which will independently look at the economics of the proposed plans before any final development commitment are made.

The Board believes that the adoption of an interest rate deferral account is not appropriate at this time. The Board further believes that the changes in the assumed debt financing in IFF10-2 are an improvement to forecasting finance expense.

9.0.0 OPERATING AND ADMINISTRATIVE EXPENSES

9.1.0 OVERVIEW

Operating and maintenance expense (also referred to as O&A, OM&A, or operating, maintenance and administration costs) is one of MH's three largest expense categories in any given year. Over 75% of MH's O&A relate to labour costs, including employee benefits. The actual and forecast operating and administrative expenses for fiscal years 2008 to 2012 are as follows:

Operating and Administrative Costs ($Millions)

	Actual			IFF10-01	
Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**
Labour and Benefits	$477.8	$509.9	$541.0	$556.3	$569.1
Other Expenses	$160.8	$177.30	$182.0	$183.9	$186.5
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)
Total Capitalized	($259.6)	($268.8)	($293.5)	($306.0)	($312.2)
O&A Attributable to Electric Operations	**$322.7**	**$364.3**	**$377.6**	**$397.7**	**$401.9**

O&A, before capitalized expenditures, has increased from $582.3 million in 2008 to $688 million in 2010. O&A expenditures were forecast to grow from $703.8 million in 2011 to $714.1 in 2012.

MH capitalized $259.6 million in 2008 or over 55% of O&A costs in that year. The level of capitalized O&A increased to $293.5 million in 2010 and MH is forecast to capitalize $306 million (43%) in 2011 and $312.2 million (44%) in 2012.

From 2005 through 2010, MH's O&A expenses have grown at a compound average growth rate of almost 5% annually while inflation for that period has been under 2%.

MH had forecast O&A to be $380 million in 2011 and $403 million in 2012 based on IFF09-1, the basis for this Rate Application. MH provided an update at the hearing with IFF MH10-1, where O&A expenses are revised to $397.7 million in 2011 and $401.9 million in 2012, as reflected in the above table. MH attributed the increases in part to accounting changes since 2009 to comply with International Financial Reporting Standards (IFRS).

9.2.0 STAFFING LEVELS

A major driver in the increase in O&A expense is due to increased staffing levels which are projected to grow from 5,769 Equivalent Full Time (EFTs) in 2004 to 6,669 EFTs, an increase of 900 EFTs or over 15%. The change in MH staffing by division since 2004 is as follows:

EQUIVALENT FULL TIME EMPLOYEES – ANNUAL RESULTS BY BUSINESS UNIT

Fiscal Year March 31,	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011 & 2012 Forecast**	**Change 2004 to 2012**
President & CEO	86	84	82	84	87	87	97	99	13
Corporate Relations	43	49	62	67	69	75	69	69	26
Corporate Planning & Strategic Analysis	18	18	19	20	19	20	23	38	20
Finance & Administration	1,025	1,032	1,029	999	986	999	1042	1,043	18
Power Supply	1,287	1,344	1,366	1,405	1,470	1,576	1,757	1,785	498
Transmission	1,207	1,208	1,221	1,233	1,255	1,298	1,355	1,358	151
Customer Services & Distribution	1,565	1,605	1,647	1,617	1,640	1,671	1,708	1,711	146
Customer Care & Marketing	538	527	552	563	545	550	561	566	28
Total	**5,769**	**5,867**	**5,978**	**5,988**	**6,071**	**6,276**	**6,613**	**6,669**	**900**

This increase in staffing levels was defended by MH as due to increased work requirements. The staffing level increases are due in part to the capital expansion plans of the Corporation, as a large number of those hired were to work on capital projects.

The last time MH expanded its generation capacity was in 1993/94 with the building of Limestone G.S.. At that time, MH had an EFT complement of 4,232, including 940 construction employees. Since then, the complement has grown significantly, well beyond the increases arising out of the acquisitions of Centra and Winnipeg Hydro. As at March 31, 2011, MH had a staffing complement of 6,299, which included 1,439 construction employees. The employee level has grown by over 2,067 EFT (over 48%) since 1993, with the number of construction related positions increasing by 499 EFT (over 53%) from 1993 levels.

9.3.0 CAPITALIZATION OF OPERATING AND ADMINISTRATIVE EXPENDITURES

MH capitalizes certain operating and administrative expenditures. MH segregates costs between operating activities (which are a direct charge against the operating income for the year) and capital activities (which are charged to future periods and amortized over the future life of a respective capital project). MH indicated that employees' timecards docket their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, MH also capitalizes overhead by applying the predetermined overhead rates to all capital projects.

MH had total operating and administrative expenses before capitalization of $543 million in 2003/04, which grew to over $688 million in 2010 and is forecast to be $703.8 million in 2010/11 and $714.1 million in 2011/12, before capitalized activities and overhead. In 2003/04 MH capitalized approximately 28% of labour and benefits. The amount of labour and benefits capitalized has increased since then, where MH now capitalizes over 32% of its labour and benefits. The increase in amounts capitalized mutes the growth in O&A expense recorded on an annual basis.

Including overhead, in total MH is forecast to capitalize $306 million of O&A expenses in 2010/11 and over $312 million in 2011/12, representing over 43% of its annual electric operating expenses in both test years.

MH also capitalizes Demand Side Management (DSM) expenditures from its Power Smart program. DSM program costs are deferred and amortized on a straight-line basis over 10 years. DSM costs are forecast at over $39 million for 2011 and $40 million for 2012. The capitalized carrying value for DSM was $168 million on March 31, 2010 and is forecast to be approximately $200 million at the end of fiscal 2012.

For fiscal 2010 MH has $591 million of deferred charges recorded as assets, including $299 million in rate-regulated assets. If MH were not subject to rate regulation, the costs would be charged to operations in the period that they were incurred.

The balances of the regulated assets at March 31, 2010 were as follows:

Regulated Assets ($ millions)	March 31, 2010
Power smart programs – electric	$168
Power smart programs – gas	32
Site restoration costs	37
Deferred taxes (CGMI)	35
Acquisition costs	23
Regulatory costs	4
Total	$299

9.4.0 MITIGATION COSTS

MH is party to an agreement dated December 16, 1977 with Canada, the Province of Manitoba and the Northern Flood Committee Inc., the latter of which represents the five First Nations communities of Cross Lake, Nelson House, Norway House, Split Lake and York Landing. This agreement, in part, provides for compensation and remedial measures necessary to ameliorate the impacts of the Churchill River Diversion and Lake Winnipeg Regulation projects. Comprehensive settlements have been reached with all communities except Cross Lake. Expenditures incurred to mitigate the impacts of the Churchill River Diversion and Lake Winnipeg Regulation projects were $26 million during fiscal 2010. As of March 31, 2010, $701 million has been spent in mitigating and compensating the project-related impacts. MH is forecasting to spend an additional $30.5 million in fiscal 2011 and $29.9 million in fiscal 2012. In recognition of the anticipated mitigation payments to be incurred, the Corporation has recorded a liability of $129 million as of March 31, 2010.

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

9.5.0 INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

9.5.1 IFRS Transition

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

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

9.5.2 Rate-Regulated Assets & Liabilities

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

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

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

9.5.3 Other Accounting Impacts

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

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

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

9.6.0 O&A COST CONTROL PROCESS

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

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

In Order 116/08 the Board stated:

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

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

In that Order the Board directed:

> *"MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most current available data and including:*
>
> *a) Primary key drivers of OM&A in each operational division [Board preferences to allow for a comparison with a greater number of other utilities].*
>
> *b) Comparable other Canadian Utility data for each of the drivers.*
>
> *c) Key comparison indicators including staffing levels.*
>
> *d) A comparison with and discussion of industry best practices.*
>
> *e) Potential improvement areas."*

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

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

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

9.7.0 INTERVENER POSITIONS

9.7.1 CAC/MSOS

CAC/MSOS questioned the growth in O&A expenditures, citing internal memos from the President of Hydro in which concerns were raised about the annual increases in O&A. Such concerns were not properly externally acknowledged in the GRA, which undermines MH's argument of ongoing expenditure controls in the 2008/09 through 2010/11 being prudent and reasonable. CAC/MSOS questioned MH's cost containment efforts, noting that they were only short-term measures that cannot be relied upon to restrain the growth in O&A in the long term.

9.7.2 MIPUG

MIPUG encouraged the Board to provide MH direction to ensure a continued restraint and tight controls on O&A spending. MIPUG recommended that the Board require MH to provide detailed reports to the Board and Interveners on corporate-wide efforts to restrain O&A and that MH continue to document and report on quantitative improvements in efficiency.

MIPUG recommended that the Board require MH to provide budget scenarios and options considered for maintaining O&A spending at inflation or at zero levels, providing a transparent process to review choices.

MIPUG further commented on the growth in personnel, whereby MH had added over 600 employees during a recessionary time, contrary to what other companies would be doing related to hiring during a downturn.

9.8.0 BOARD FINDINGS

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

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

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

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

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

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

10.0.0 DEPRECIATION AND AMORTIZATION

10.1.0 OVERVIEW

In the test years, depreciation and amortization is the second-largest expense category to be recovered through rates. Depreciation expenses were $358 million in fiscal 2010 and have grown to $366 million in fiscal 2011.

MH last instituted new depreciation rates on April 1, 2007. MH's last Depreciation Study by Gannett Fleming dated March 31, 2005 was filed at the 2008/09 GRA. Although a 2010 Depreciation Study was previously anticipated for this GRA, MH deferred the study pending integration of the IFRS requirements. MH at that time also deferred the Board-directed Asset Condition Assessment to circa 2013.

MH's depreciation and amortization expense is forecast to be $405 million in fiscal 2012, an increase of $47 million since fiscal 2010. MH attributed the increase to a higher level of net assets. Depreciation and amortization is now forecast to grow to over $830 million by 2030 with the new major generation and transmission projects.

10.2.0 DEPRECIABLE ASSETS

MH's IFF10-2 has 2010/11 gross electrical utility asset values of $12.6 billion which have been depreciated down to $7.8 billion.

Going forward, IFF10-2 projects the gross assets and depreciated assets to be as follows:

Net Plant In-Service ($Billions)

	Plant in Service	Accumulated Depreciation	Net Plant In Service
2015/16	17.4	6.8	10.5
2020/21	28.7	9.5	19.2
2025/26	39.9	13.0	26.8
2029/30	42.5	16.4	26.1

MH's 2005 depreciation study apparently uses industry standards for the life expectancy of various facility components e.g.:

- Hydraulic Generation Facilities:

  – Civil Works – 100 years life with the extensive rehabilitation works required on most of the Winnipeg River plants over the last 2-3 decades. A reconsideration of the 100 year life expectancy might be acceptable.

  – Turbines and Generation - 65 years life. The significant remedial works required in the last two decades on Grand Rapids/Jenpeg generation units suggest a shorter life expectancy could be appropriate for all.

  – Accessory Equipment - 50 years life. Shorter life expectancy could also be suggested.

- Thermal Generation Facilities:

  – Steam plants - 65 years life. MH's ongoing investments in the Brandon and Selkirk plants may not support the notion of a 65 year life.

  – Natural gas combustion turbine - 25 years life. Some questions of the true economic value of these plants remain.

- Transmission Lines:

  – Towers - 75 to 85 years life. Events on Bipoles I and II in 1996 and 2011 suggest remediation of failed or damaged facilities could reduce the effective life cycles.

  – Conductors - 60 years life. Aside from the former Winnipeg Hydro transmission upgrades, MH has indicated a need for early replacements.

- HVDC Converter Stations:

  – Structures - 57 years life. No indication of problems exists.

  – Serialized equipment - 37-43 years life. Indications from prior evaluations are that the serialized equipment (synchronous condensers) may need replacement in 20 to 50 years.

10.3.0 BOARD FINDINGS

Depreciation (amortization) expense is forecast in this application based on an out-dated 2005 depreciation study. The Board is aware that a result of IFRS requirements for componentization will likely lead to an increase in depreciation expense, as components will have to be carved out and depreciated over their respective shorter service lives rather than over a longer service life of the asset as a whole. The Board understands that a new depreciation study is being prepared.

The Board remains concerned that an Asset Condition Assessment Study has been delayed and notes that several of the assets, which are being depreciated over long periods of time, may require major repairs in the interim.

There does not appear to be any explicit recognition of the physical condition and ongoing repairs associated with the individual generating stations or transmission facilities. This suggests that MH may not have an adequate history of physical plant conditions and rehabilitation needs such as would be included in an "Asset Condition Assessment". The Board will require MH to file an Asset Condition Assessment and depreciation study at the next GRA.

11.0.0 PAYMENTS TO GOVERNMENTS

As a Crown Corporation, MH does not pay income tax, provincial sales tax or the Goods and Services Tax. MH does, however, pay the Provincial Corporations Capital Tax, similar to other privately held corporations employing capital in Manitoba. The Province of Manitoba also levies a number of other fees to be paid by MH. Forecast payments to the Province were $ 240 million in 2010, $ 244 million in 2011 and $236 million in 2012.

The total payments to the Province from fiscal 2005 through 2012 are summarized as follows in the following table:

PAYMENTS TO THE PROVINCE ($MILLIONS)

	Actual					IFF09-1		
Fiscal Year	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Corporations Capital Tax	35	36	37	39	44	45	47	44
Payroll Tax	7	7	8	8	9	9	9	9
Water Rentals	104	124	106	117	115	111	102	100
Debt Guarantee Fee	68	66	68	70	70	72	78	83
Sinking Fund Admin Fee	1	-	-	1	1	1	-	-
Provincial Mitigation or Settlement Obligations	13	2		2	-	2	8	-
Total Payment	**228**	**235**	**219**	**237**	**239**	**240**	**244**	**236**
Total Payments as a Percentage of MH's Gross Revenue	14%	13%	13%	14%	14%	15%	15%	13%

MH is forecasting paying $380 million to the Province in 2020, which is approximately $150 million higher than current levels. Payments to the Province will increase when the new generation and transmission projects are built.

MH pays Corporations Capital Tax to the Province based on 0.5% on its invested capital. The Corporations Capital Tax is a function of the level of debt of MH. The Corporations Capital Tax has been phased out for all corporations effective January 1, 2011 except for Crown Corporations, Banks and Trust Companies. As such, MH will remain subject to Capital Tax.

Water rentals relate to the use of provincial water resources, and are paid on a monthly basis to the Province based the greater of:

- Energy produced, at a current rate of $3.341 per MWh, or
- The installed capacity of the facility at a rate of $8.13 per installed horsepower.

The Provincial Debt Guarantee Fee is 1.0% of the sum of the balance of MH Bonds, provincial advances to MH and provincial short-term promissory notes outstanding to guarantee MH long-term debt.

The Sinking Fund Service Charge is 0.075% of the amount of the sinking fund balance, and is paid to the Province for managing MH's sinking fund balance. MH's sinking fund is a covenant related to its bond issues.

In addition to the payments to the Province, MH makes Grants in Lieu of Taxes (GILT) to municipalities on buildings and structures throughout the Province. In 2009 MH made $11 million in GILT payments. The payments are forecast to increase to $15 million in 2010, as a result of the new Corporate Head Office inclusion in the tax rolls. MH indicated the property and business tax on Corporate Head Office to be $3.8 million per year.

11.1.0 BOARD FINDINGS

The Board notes that MH makes a significant contribution to the Province and to Manitoba municipalities. The payments to the Province in particular represent 15% of the gross revenue of the utility, a significant amount. The total amount to be paid to the Province is expected to grow substantially over the next twenty years, primarily due to the now-planned new major generation and transmission investments, these through increases in borrowings, increased capital, and higher water rentals as the new generating stations are built.

The Province’s financial interest in the contemplated generation and transmission investments due to potentially higher government underscores the need for an independent arm's-length review of the economics of these projects.

12.0.0 FINANCIAL TARGETS

In September 1995, MH adopted the following financial targets, which were reviewed by the Board at prior GRAs and the current hearing:

1. To achieve and maintain a minimum debt-to-equity ratio of 75:25 by no later than 2005/06;

2. To achieve and maintain an annual gross interest coverage ratio of 1:20 to 1:35 annually; and

3. To fund all new capital construction requirements except major new generation and/or major new transmission facilities, plus the new head office, from internal sources.

MH's financial targets have varied over the years due to changing circumstances and priorities. Since the original 1995 date, the targets have changed as follows:

Year	Financial Target
1995	75:25 debt equity ratio by 2005/06, interest coverage ratio of 1.20 to 1.35 and fund all capital expenditures, except major new facilities, from internally generated funds
2001	75:25 debt equity ratio by 2005/06, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new facilities, from internally generated funds
2002	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.10 and fund all capital expenditures, except major new facilities, from internally generated funds
2007	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new facilities, from internally generated funds

As of March 31, 2002, MH had a debt/equity ratio of 77:23. MH stated that the largest single factor contributing to the delay in the achievement of the 75:25 debt/equity target was the 2002 to 2004 drought. The drought resulted in an approximate $600 million reduction to net export revenues relative to a normal flow period and severely impeded

MH's progress toward its financial targets. In 2002, the target year was changed from 2005/06 to 2011/12 to allow for a more gradual rate impact on customers.

12.1.0 DEBT-TO-EQUITY RATIO

The debt-to-equity ratio measures the relationship of long-term and short-term debt less short term and sinking fund investments to equity (retained earnings including AOCI and unamortized customer contributions). This ratio is used to assess the overall financial risk to MH by examining the level of debt in relation to the amount of equity held. MH has established a debt-to-equity ratio target of 75:25 by fiscal 2012.

MH attained the 75:25 debt-to-equity ratio target in 2010, an accomplishment not contemplated at the last GRA. Since the 2004 drought, the capital structure has improved from 87:13 in 2004 to 73:27 in 2010. The improved financial position relates to higher-than-expected extra-provincial revenue and rate increases granted by the Board, which on a cumulative basis have totalled 22% since 2005.

MH is now forecasting increases of 3.5% annually for the years 2013 tto 2021 (a cumulative 39% increase) but due to its planned spending on major new generation and transmission projects, MH's capital structure is forecast to weaken from the 75:25 target to a debt-to-equity ratio of 84:16 in 2021.

In support of its application, MH had filed IFF09-1 and CEF09-1. MH had anticipated capital spending of $ 13.1 billion on its three major generation and transmission projects (Keeyask G.S., Conawapa G.S and Bipole III). With the upward revised capital cost of these three projects reflected in IFF10-2, the capital cost has increased to over $16.6 billion, which is over $3.5 billion higher the cost forecast in CEF09-1.

Long-term debt was forecast to grow from $7.8 billion in 2010 to $17.7 billion in 2029. Based on the revised capital forecast, long-term debt is to balloon to over $23 billion in 2029, an increase in long-term debt of $5.0 billion from the previous forecast. The higher debt level will result in materially higher debt servicing costs, which over the forecast period has reduced the net income by $3.2 billion from the amount forecast in IFF09-1. The change in forecast net income and the debt-to-equity ratio from IFF09-1 to IFF10-2 is as follows:

	Net Income ($ Millions)			Debt : Equity Rato	
Fiscal Year Ending March 31,	**Iff09-1**	**IFF10-2**	**Difference**	**IFF09**	**IFF10-2**
2010	129	163	$34	74:26	73:27
2011	88	158	$70	75:25	74:26
2012	98	134	$36	76:24	74:26
2013	83	132	$49	76:24	77:23
2014	137	198	$61	78:22	78:22
2015	122	155	$33	79:21	79:21
2016	260	230	($30)	80:2	81:19
2017	271	278	$7	80:2	81:19
2018	246	227	($19)	80:2	82:18
2019	257	120	($137)	80:2	83:17
2020	287	198	($89)	79:21	83:17
2021	307	12	($295)	79:21	84:16
2022	450	244	($206)	78:22	83:17
2023	554	332	($222)	76:24	83:17
2024	744	392	($352)	73:27	82:18
2025	805	504	($301)	70:3	80:2
2026	922	462	($460)	66:34	79:21
2027	1019	552	($467)	61:39	77:23
2028	1127	648	($479)	56:44	74:26
2029	1237	753	($484)	51:49	72:28
Total	**9441**	**5892**	**($3 549)**		

The debt-to-equity ratio in 2029 has changed from 51:49 in IFF09-1, a particularly strong balance sheet, to 72:28 in IFF10-2, representing a materially negative financial change from one forecast to the next. Changes in GAAP with the move to IFRS in fiscal 2013 will likely further hinder MH's progress to its debt-to-equity target.

12.2.0 INTEREST COVERAGE RATIO

The Interest Coverage Ratio is calculated to measure the degree to which net income before interest exceeds finance expense. The interest coverage ratio indicates the extent to which net income is sufficient to pay gross interest on debt. An interest coverage ratio below 1 indicates that a company cannot support interest-servicing costs from operations and may require further borrowings to cover the interest charges. MH has established a target interest coverage of 1.20 in all years.

In IFF09-1 the target is not achieved, with shortfalls from fiscal 2011 to 2015. The interest coverage ratio falls within the range of 1.11 to 1.19 during that period. The interest coverage was forecast to be 2.22 in 2029.

MH filed an update based on IFF10-2, which reflected lower than forecast interest rates in the next few years. As a result of this change, MH now forecasts to meet its interest coverage ratios during each of the years 2011 through 2018. However due to the increase in capital costs of $3.6 billion and additional borrowings of over $5 billion, in the years 2019 through 2022 the interest coverage ratio will be below target. In particular, the forecast indicates that in 2021 MH will have an interest coverage ratio of 1.01.

In 2029, the interest coverage ratio has now been revised down from 2.22, based on IFF09-1, to 1.50. This is above target, but materially lower than what was indicated in IFF09-1. Further upward revisions in the capital cost of the major generation and transmission projects and any upward movement in interest rates above what is forecast could negatively impact the interest coverage ratio.

12.3.0 CAPITAL COVERAGE RATIO

The Capital Coverage Ratio measures MH’s ability to make capital purchases without additional borrowings, measuring the extent to which internally generated funds are sufficient to fund capital expenditures during the year. The Capital Coverage Ratio does not include the major generation and transmission projects in its determination. If such projects were included, it would indicate that MH has a Capital Coverage Ratio well below 1.0 and that the funding for the new projects is supported primarily if not solely by new debt issues.

12.4.0 INTERVENER POSITIONS

12.4.1 CAC/MSOS

CAC/MSOS stated that in the short term the overall retained earnings and debt ratio for 2011/12 is better than originally forecast in IFF 09–1, and that the current outlooks in IFF 10–2 for 2010/11 and 2011/12 in terms of the debt ratio are both better than what was forecast in IFF 09-1. The current outlook for the test years does not support the need for rate increases greater than those already approved on an interim basis. CAC/MSOS noted that it could even be argued that the interim rate increases approved could be rolled back and would still result in a financial position at least as favourable as those originally expected in IFF 09–1.

CAC/MSOS further noted that the cost of construction of the major generation and transmission projects as they progress affects MH's balance sheet and its debt-to-equity ratio. To the extent that assets are funded through debt, it will affect the debt-to-equity ratio. Since the Board uses of the target ratio as a measure of financial soundness, this puts pressure on rates to increase to maintain the target.

CAC/MSOS adopted the evidence of Greg Matwichuk, who stated that less reliance should be placed on retained earnings and the debt-to-equity ratio for the purpose of rate-setting on a go-forward basis. Mr. Matwichuk stated that changes in MH’s debt-to-equity ratio have no apparent impact on the Province’s credit rating, noting that after the drought in 2003/04, the debt-to-equity ratio was 88:12, which resulted in no reduction to the Province’s bond-rating grade.

Mr. Matwichuk recommended that MH establish a Rate Stabilization Reserve (RSR), a regulatory mechanism to stabilize rates that may otherwise sharply increase due to the effects of unanticipated events. The RSR would provide MH ratepayers some level of protection against large rate increases that may become unavoidable due to sudden or unanticipated adverse conditions. Mr. Matwichuk noted that a similar mechanism is in place at Manitoba Public Insurance.

RSRs exist at regulated entities such as hydroelectric utilities, water utilities, local gas distribution companies and insurance companies and are typically utilized by utilities which are subject to weather- or and/or water-related factors that complicate forecasts and result in variances.

CAC/MSOS submitted that the establishment of an RSR for regulatory purposes is appropriate for MH due to significant variances in forecasting, observed volatility in export revenue, and MH's vulnerability to known contingencies with uncertain timing and impact. Mr. Matwichuk stated that an RSR would assist in managing the impact of risk to domestic ratepayers. Under his proposal, when export revenues exceed forecast export revenues, the excess would be set aside to be amortized over five years The same approach would be taken to years in which export revenues fell below the forecasted level, meaning that deficits would also be amortized over a five-year period. Under such a mechanism, the net unamortized equity or deficit arising out of export revenue differentials from forecasts would remain on the balance sheet as a form of a RSR, segregated from the general equity.

12.4.2 MIPUG

MIPUG stated that MH is in the best financial position that it has been in its history, exceeding the 75:25 debt-to-equity ratio with close to $2.5 billion in retained earnings. Based on the most current forecast, retained earnings should be increased to $4.3 billion.

With respect to the debt-to-equity target of 75:25, MIPUG stated that the true value of Hydro's assets is significantly higher than their book value. While the 75:25 debt-to-equity target is important, it is an artificial number and does not show the true strength and value of MH and its assets. MIPUG submitted that such information should provide some comfort to the Board.

Bowman & McLaren stated that the planned increase in net plant in service is a key driver in the change in the forecast debt-to-equity ratios and that the impact of a higher level of capital expenditures will have increasing cumulative impacts on the level of net income in the future. The current 75:25 debt-to-equity ratio is reflective of a retained earnings level approximately equal to the benchmark of a five-year-drought. However in the latter part of the IFF, given the capital spending proposed, the 75:25 debt-to-equity ratio target may generate retained earnings levels that may exceed the calculated cost of a five-year-drought at that time.

As the degree of capital investment increases, the relevance of the debt-to-equity target will diminish. Given the provincial debt guarantee, the debt-to-equity ratio is not as important for a public utility as opposed to what it would be for a private enterprise.

MIPUG submitted there is nothing in the evidence that indicates that MH cannot handle a five-year drought and will not have the cash flow to survive it. MH has one of the lowest electricity rates in North America, so there would be a lot of room to adjust rates, and all the forecasts show that MH would recover from a net loss without having to impose rate shock on customers.

MIPUG did not agree that water reservoir levels should be used as a rate stabilization mechanism as proposed by KM, nor did MIPUG believe that an RSR mechanism as proposed by CAC/MSOS should be implemented. The utilization of water levels as a reserve may result in suboptimal use of the resource and lead to a reduction in revenues in some cases. Adjusting lake levels by one or two feet would not be a good strategy if money ends up being lost each year because water is spilled instead of being used to sell energy on the export market.

MIPUG further submitted that the RSR mechanism as proposed by CAC/MSOS would not improve transparency and is not required because the Board's rate-setting process is effective. If the Board were to consider establishing an RSR, Bowman & McLaren noted that an orderly process as identified by the Board in Order 116/08 would have to start with the step of identifying and properly quantifying MH's risks in advance of addressing the appropriate form of reserves. This would be a matter for future consideration. Should a financial reserve target be desired in the future, the value may be derived based on targeting a long-term rate stability criterion which would include periods leading up to, during and following a benchmark drought. Such an analysis could be completed using probabilistic tools as identified in the KM report.

12.5.0 BOARD FINDINGS

Despite the concerns the Board has with respect to the "firmness", if not validity of the equity components of MH's debt-to-equity target ratio, the Board notes that MH currently has achieved its debt-to-equity target and that to maintain the 75:25 ratio it will require rate increases far higher than that currently contemplated in the IFF.

The current view of capital spending for major generation transmission, with current estimates $3.6 billion higher than in IFF 09–1, reflects an ever-increasing debt load, higher forecast carrying charges, lower income approximating $3.2 billion and a further deterioration in the capital structure of the Corporation over the next 20 years. This deterioration is predicated on increasing rates over the forecast time frame by approximately 60%.

The Board remains concerned that export revenues, which were negotiated when the capital costs of the major projects were projected to be much lower, have been locked in, yet the projected capital costs have increased unabated. These increased costs will have to be paid for somehow, and in the absence of export customers paying them, the burden will fall on domestic customers. An NFAAT process should be established to review the implications of the proposed development plans on MH's capital structure.

The Board notes that the financial capital structure of MH was to peak at 80% debt and 20% equity in 2019. Based on updated estimates, the debt portion has grown to over 84% in 2021 and is not to return to current target (and currently attained) levels at the end of the forecast period 2030. In IFF 09–1, the 75:25 debt-to-equity financial target was reached in 2024 and, optimistically, a debt-to-equity ratio of 51:49 was projected for 2029. The Board questions whether the debt-to-equity financial target of 75:25 for rate-setting purposes should be revisited, given that it is currently forecast not to be attained over the 20-year financial outlook.

Any further increase in capital costs for the major capital projects will come at the price of a further deterioration in MH's capital structure. This may require greater rate increases from domestic customers than those currently projected.

As for the interest coverage target of 1.20, the Board remains concerned that a decline in export revenues due to a structural change in the markets into which MH delivers its electricity could have grave consequences to MH's ability to meet its debt obligations. These are currently forecast to be $23 billion when the projects are completed. Interest rates, if they increase beyond forecast levels during the development and construction of the major generation and transmission projects, could further increase the debt and associated carrying costs incurred by MH. To the extent that projected revenues will not materialize, MH would still be required to meet its debt obligations.

The Board notes with concern that under the most recent forecast, the interest coverage ratio comes very close to 1.0 during one of the years of the planning horizon. This suggests that MH may come close to being unable to meet its interest obligations from its operations and will be, if the ratio falls below 1.0, in the position of having to borrow additional funds to meet its interest obligations.

Interest costs will be over $1.5 billion on an annual basis once the projects have been completed, which will have to be met by revenues from both domestic and export customers. To the extent the export revenues do not materialize as planned, the burden will fall to the domestic ratepayer. It is vitally important that the economics of the proposed generation and transmission investments be subject to a thorough review to ensure that the developments, if they proceed, will benefit and not overly burden domestic ratepayers.

The Board does not see merit in establishing an RSR based on excess or deficient export revenue. While the Board remains concerned about MH's ability to achieve its export forecasts, an RSR mechanism would not assist in smoothing out the rate implications of a shortfall.

The Board believes that the current rate-setting mechanism, including the presentation of forecasts that are tested in a rate hearing, provides an appropriate mechanism for setting rates. The Board does, however, see merit in exploring whether establishing an RSR is appropriate for other reasons.

The Board believes that having reviewed the risks faced by MH, sufficient information exists to move one step further towards assessing whether a mechanism such as an RSR would be appropriate in establishing future rate sufficiency. While the Board does not believe that an RSR mechanism should be established at this time, it should be one of the mechanisms to be considered by this Board at a future GRA.

The Board further believes that since MH's proposed capital expenditure plan is subject to material escalations, some consideration should be given to de-linking rate requirements from the debt-to-equity ratio target of 75:25. Instead, rate requirements should be more focused on an amount sufficient to meet the risks faced by the Corporation.

13.0.0 LOAD FORECASTS

13.1.0 OVERVIEW

MH's Load Forecast is used to predict when new generation and transmission assets are needed to serve MH's load. MH's 2010 GRA was premised on a May 2009 Load Forecast which only partially reflected the economic downturn. In PUB/MH II 194(a), MH confirmed a domestic load reduction of 1,000± GWh from May 2008. This did not include any plant closure impacts.

MH's Updated Domestic Load Forecasts indicate a significant downward trend in the forecasts from 2008 onward. This trend reflects the economic downturn after 2008/09 and the closure of the pulp and paper plant at Pine Falls. However, according to MH these forecasts do not include the impact of pending closures of smelter operations in Flin Flon and Thompson, which according to MH's testimony would reduce consumption by about 500 GWh after 2015/16.

13.2.0 INDUSTRIAL CUSTOMER CONSUMPTION

The table below provides an industrial energy consumption history and forecast from 2005/06 to 2009/10 and beyond. It is apparent that the total industry consumption totals are very similar to MH's total Top Consumer usage.

Industrial load growth has essentially stalled since 2005/06. Even without the pulp and paper plant shutdown, MH's industrial load would have shown little or no growth in the last 5 years. From the table below it is apparent that MH's expectations of high industrial load growth in the chemical and petroleum sectors will not be realized in the short term.

In the most recent Load Forecast, MH is looking for growth of 100 GWh per year in Top Consumer load. If correct, this would add about 700 GWh to energy consumption and offset the smelter closures by 2015. If this new load does not materialize, MH's total industrial consumption would remain near the 5,000 GWh/year level.

MH's industrial customers were targeted for higher rates during the Energy Intensive Industrial Rate (EIIR) hearing. The logic employed suggested that Manitoba industries were paying less than market value for energy consumed. Consequently, MH considered that the utility was losing money for all increases in energy sold at approved rates to GSL and GSM customers.

In Board Order 112/09, MH was directed to limit the new EIIR to new peak energy consumption. This reflected the circumstances of 2007/08, when average MISO Market prices were in excess of 4¢/kWh during peak periods but were at the 2¢/kWh range during the off-peak periods.

The market circumstances in 2009/10 and 2010/11 have shown that GSL and GSM customers are paying at least peak MISO Market prices and considerably more than off-peak MISO Market prices. MH has yet to abandon the EIIR concept, but has seen some industrial customers move to higher levels of consumption than contemplated in the EIIR hearing.

13.3.0 RATE IMPACTS ON LOAD GROWTH

It is the Board's understanding that all GSL & GSM customers are subject to the same (unchanging) demand charge per kVA and the same (progressively increasing) energy charge per kWh regardless of peak or off-peak consumption. To date, MH has declined to offer time-of-use rates to these customer classes. Apparently industrial customers are not entitled to access low cost off-peak energy on the same basis as MH's export clients.

Given the low MISO market prices, a potential problem looming for MH's industrial customers is that they may be paying significantly more for energy in the next 10 to 20 years than utility customers in the adjoining MISO states. If that ends up being the case, cheap electricity may no longer be an economic advantage of doing business in Manitoba.

13.4.0 DOMESTIC LOAD DEMANDS FOR NEW GENERATION

MH's 2008/09 Power Resource Plan contemplated a Keeyask G.S. in-service date of 2018 and a Conawapa G.S. in-service date of 2022. The 2008 Base Load Forecast along with existing NSP sales, an NSP sales extension, and the new WPS-500 MW/MP-250 MW term sheets were the apparent drivers for these in-service dates.

Domestic energy consumption, rather than peak winter demand, was viewed as the critical factor, with energy shortfalls anticipated as early as 2011/12. A need was seen for contracted imports until 2015 when the level of contract sales to NSP would be reduced.

The 2008 Base Load Forecast foresaw a domestic load of 28,100 GWh by 2015/16, reflecting 8,040 GWh of energy usage by Top Consumers.

MH's IFF10-2 lowered the 2015/16 domestic load forecast to 25,700 GWh (including 6,666 GWh of Top Consumer load, which may still be too optimistic). This differs significantly from the 27,300 GWh projection for 2015/16 set out in IFF08-1 when MH saw a need for Keeyask G.S. by 2018/19 to allow the new export sales.

13.5.0 INTERVENER POSITIONS

13.5.1 CAC/MSOS

CAC/MSOS did not take issue with MH's overall domestic load forecast. Some concerns were expressed about:

- the level of electric car growth included in general service;
- the residential load growth projections;

- the lack of growth in commercial sector load; and
- the decline in industrial sector load.

13.5.2 MIPUG

MIPUG did not offer any new insight on the recent loss of industrial load and the potential for existing customer growth and/or new industries coming to Manitoba. It appears that following another round of consultation, MIPUG now supports MH's pending EIIR initiatives.

13.5.3 RCM/TREE

RCM/TREE continues to express concern about the limited achievements with respect to energy conservation and continues to favour increased exports over higher levels of domestic load growth.

13.6.0 BOARD FINDINGS

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;
- may well be overly optimistic given the stagnation and/or lack of growth over the last five years in the industrial sector; particularly when coupled with the actual pulp and paper plant closure and imminent smelter closures; and
- do not support the significantly advanced dates for new generation, but rather, in the absence of the new contracts, suggest a 2024/25 in-service date for domestic load only.

The Board understands that the recent MP & WPS contract announcements essentially commit MH to building Keeyask G.S. by 2020/21. This is about five years earlier than domestic need only would indicate.

While the Board appreciates that MH's domestic revenue growth from the residential and commercial sectors has largely offset the revenue decline experienced to-date in the industrial sector, it does not share MH's optimistic view of any early dramatic recovery in the latter. And, the continuing prospect of the future implementation of an EIIR could well hinder such a recovery.

The Board is still awaiting MH's re-filing of the EIIR, as directed in Board Order 112/09.

14.0.0 POWER SUPPLY

14.1.0 DC TRANSMISSION SYSTEM

14.1.1 Reliability Case for Bipole III

MH holds that Bipole III is required for domestic system reliability, and that the significant costs that would be expended on its construction, including the cost of converter stations, should not be attributed to any degree to either the planned new generation projects on the lower Nelson River (Keeyask G.S. and Conawapa G.S.) or to export customers. The coincidental outage of Bipoles I and II that occurred in the fall of 1996 has been cited as an example of the reliability risks that currently exists and needs to be addressed.

MH did not provide an analysis of any of the various events that could lead to the loss of HVDC power. Tornadoes, wind shear, forest fires and ice storms have, at various times, been identified as the most likely triggers of such an outage. All of these extreme events are more likely to occur in either the spring, summer or fall, rather than in the winter. In mid-winter, the biggest risk that has been identified is an ice storm that “takes out” some of the transmission towers.

In January 2011, a large number of Bipole I and II towers were threatened by ice formation within flooded right-of-ways. This presented a real risk. The transmission towers appear to need to be flood-proofed as soon as possible, whether or not Bipole III, or another reliability upgrade, is put in place.

It is unlikely that Bipole III, if constructed, would be built to less than a capacity of 2,000 MW. While the Board’s Vice Chair accepts MH’s evidence that Bipole III is required for reliability purposes, the Chairman suspects that an alternative reliability measure that could potentially replace Bipole III would be the addition of CCCT natural gas generation capacity (perhaps to be developed in “smaller steps”, e.g. 400 to 500 MW at a time) to address the risk of an outage of either or both existing Bipoles.

MH compared the available aggregate Bipole I and II capacity of 3,354MW to the maximum 3,562MW generation capacity of the three existing Lower Nelson River generating stations, noting a 208MW deficiency. It is not clear what circumstance would require 100% output from these three plants to meet only domestic demand. Force majeure provisions in existing and new export contracts should allow for curtailment of export contract commitments in the event of a Bipole outage.

14.1.2 Reliability Alternatives

In June 2011, MH filed a 20-year Financial Outlook that included a comparison of the current plan for the construction of a 2,000 MW Bipole III (to be on-line in 2017/18) with a 2,000 MW natural gas generation plant to serve as an alternative. From the information provided by MH, it appears that comparison involved an SCCT plant rather than a CCCT plant, although a CCCT plant is clearly preferable due to its higher efficiency. The analysis that was provided was not detailed, and neither set out annual finance and depreciation costs nor recognized the potential revenue stream from a natural gas generation alternative.

As set out above, the Board's Vice Chair accepts MH's reasoning that Bipole III is required for reliability purposes. For the Vice-Chair, without Bipole III, the value of all lower Nelson River generation facilities (existing and planned) are jeopardized, in as much as a catastrophic failure of Bipole 1 and 2 would eliminate access to 75% of MH's hydro-electric power to southern Manitoba and export customers.

The Chairman, on the other hand, is of the view that there could be several advantages associated with a CCCT natural gas plant instead of Bipole III, which involve economics, risk management and the environment. A CCCT plant can be constructed at a fraction of the cost of Bipole III, and would provide MH with resource diversity that is currently absent. In the event of Bipole I and II being out of service, CCCT production and/or imports could be employed. MH's current diversity agreements with its American counterparties involve the receipt of coal-fired generation electricity in the winter. A

Manitoba-based CCCT plant would involve approximately half the emissions of coal-fired generation. The Chairman accordingly recommends that before Bipole III is constructed, the CCCT natural gas generation alternative should be investigated thoroughly.

In a prior Power Resource Plan, MH examined the cost of CCCT natural gas generation and concluded that a 400 MW CCGT produces about 3,100 GWh of dependable energy per year, which is slightly more than the projected dependable output of Keeyask G.S. Its capital cost was estimated at $471M and, because of its high efficiency, such a plant could produce energy at an operating cost of $55/MW or $8.40/GJ. (If, in the future, a price was put on carbon, a $30/tonne carbon cost would add less than $10/MW to the cost of operation.) Currently, natural gas is priced at $3.00 per GJ on the spot market, a mere 20% of the commodity's peak price. The reduction can be attributed partially to the slow recovery from the recession and partially to the availability of shale gas.

In its 2011 analysis, MH priced the capital cost of a 2,000 MW CCCT plant at almost $3.0B (25% higher than in 2008/09). With current natural gas costs at less than $5.00/GJ, the total on-line costs including finance, depreciation, maintenance and fuel costs would now be in the 5 to 6¢/kWh range.

14.2.0 AC TRANSMISSION SYSTEM

14.2.1 North-South Transmission

MH forecasts a need for "additional (AC) transmission from Northern Manitoba to Winnipeg" when Conawapa goes into service, now slated for 2023/24. MH's CEF-10 projection of capital costs budgeted $313 million for such a facility but did not specifically define its function or purpose.

MH has not explained its rationale for the additional AC transmission or its timing. A question that, among others, remains to be answered is whether this proposed AC addition is related to the west side siting of Bipole III and/or Bipole III capacity with or without export commitments.

14.2.2 Dorsey to U.S. 500kV AC Transmission.

CEF-10 also provides $205 million for additional Manitoba sited AC transmission to the U.S., to be in service by 2018. Presumably, this allocation was in anticipation of a 500 MW sale to WPS and a 250 MW sale to MP. With the WPS sale reduced to 100 MW, it may be that the expanded capacity could be deferred.

14.3.0 BIPOLE III FOR EXPORTS

MH notes that in the absence of the 2,000 MW Bipole III transmission line the construction of Conawapa G.S. should not occur. And, now seemingly without the 500 MW WPS sale, MH has decided to defer the construction and in-service date of Conawapa G.S., but still plans to proceed with Bipole III.

MH asserts that the planned Keeyask G.S. could not operate at maximum output in high-flow conditions without Bipole III. The assumption of a deemed requirement for 100% of Keeyask's potential generation in high flow conditions to be transmitted on Bipole III involves the prospect of opportunity export sales as well as both domestic load and firm export contracts. The availability of "dependable energy" does not require 100% of Keeyask's output.

Under the assumption that hydraulic generation is to be used to supply all firm/dependable energy in an average-flow year, MH holds that the existing Bipole I and Bipole II capacity is insufficient to convey the output from Keeyask G.S. plus the power generated from the three existing Lower Nelson River generating stations.

As set out above, the Chairman and the Board's Vice Chair are of two views with respect to MH's reliability arguments. The Chairman is of the view that MH's assumptions, which support a requirement of Bipole III if Keeyask is built, should be fully tested prior to MH making a final commitment to both Keeyask and Bipole III. The

Board's Vice Chair is of the view that Manitoba Hydro has established that Bipole III would be required for reliability purposes in any case.

14.4.0 INTERVENER POSITIONS

Recognizing that the Board was not asked or tasked to approve Bipole III, the Interveners only expressed concern with the seemingly ever-increasing costs of Bipole III and Keeyask, and with the cost revision process itself.

14.5.0 BOARD FINDINGS

The findings of the Chairman and the Board's Vice Chair differ with respect to MH's reliability case for Bipole III.

The Vice Chair is of the view that MH has established that Bipole III is required for reliability purposes even absent any additional export commitments, as the concurrent outage of Bipoles I and II presents a significant risk to MH's customers. The fact that a concurrent outage of both transmission lines is not without precedent (as it happened in 1996), and the fact that ice formations again threatened both existing Bipoles in 2011, indicates that an outage of the lines is a distinct possibility. It is also clear that the existing capacity of the three existing Lower Nelson River generating stations at 100% output already exceeds the capacity of the existing two Bipoles.

The Chairman, on the other hand, is of the view that MH has not sufficiently re-evaluated the Utility's initial view that Bipole III is required and that its construction will not "drive up" Manitoba's domestic rates, given reduced domestic demand, reduced overall exports and export pricing, and scaled down WPS export commitments.

While the Board lacks a mandate to approve MH's capital expenditures, particular capital expenditure plans predicated on export sales, the Board has to consider the economics of such expenditure plans because, in the absence of assured additional, profitable and sufficient export revenue, domestic rates could well increase materially.

To date, the Board has not been provided with any cost/benefit and domestic rate analyses supportive of the level of capital expenditure now being contemplated. In the Chairman's view, there are identified alternatives that should be thoroughly vetted before spending more funds and committing Manitoba consumers to meet any shortage of revenue that may arise with respect to meeting the projected costs of Bipole III. To that extent, MH's contention that Bipole III is being built for domestic reliability needs would best be supported by a review that includes the development of a clear definition of the various seasonal situations that could trigger the failure of Bipole I and/or Bipole II. If lower domestic rates could be expected to develop without Bipole III (or without Keeyask and/or Conawapa) within the long-term planning horizon of twenty years without any additional reliability risk, then the plans that would support such an outcome should be seriously entertained, certainly before further commitments are made to the planned capital projects.

Similarly, in the Chairman's view, if the construction of a CCCT natural gas generation plant of sufficient size can be found to provide a higher net present value than MH's current preferred development plan (Bipole III, Keeyask and Conawapa), then ratepayers should be made aware of this opportunity, as well as the projected domestic rate differential between MH's preferred plan, towards which MH has already spent and continues to expend significant funds, and a different plan, such as one that involves a CCCT natural gas generation plant in southern Manitoba.

Exports appear to be the primary driving force for the "early" (ahead of domestic need) in-service date for Keeyask G.S.. The Chairman is of the view that the export revenues expected to be generated by the new generation plant appears to also represent the impetus for an early in-service date of Bipole III. The Vice Chair does not share this view. As set out above, the Vice Chair is of the view that Bipole III is a required reliability measure even in the absence of additional export capacity.

Both the Chairman and Vice Chair believe that absent Keeyask, the construction of Bipole III can be expected to increase domestic rates. The question that remains is whether if Keeyask is built, the construction of Bipole III will still increase domestic rates. The Chairman is hopeful that both capital projects will be subjected to a full NFAAT hearing. The Chairman notes that if an economic case can be made for the deferral of Bipole III, Manitoba ratepayers would be the beneficiaries of lower electricity rates, as 100% of Bipole III's costs (not only the capital costs, but also the finance and operating costs associated with it) will, under MH's cost allocation, be borne by MH's domestic consumers. The Vice Chair does not share this view, and believes that while an NFAAT may be warranted for any new generation capacity, Bipole III should not be delayed. MH has advised, and has filed with a Board a letter from the Provincial government confirming, that an NFAAT review will be scheduled for the major capital projects.

15.0.0 ENERGY SUPPLY

15.1.0 HYDRAULIC GENERATION

15.1.1 Watershed Components

MH's hydraulic generation relies on flows originating in five large watersheds, as follows:

	Drainage Area (sq. mi.)
Lake Winnipeg Watershed	380,000
Winnipeg River	53,000
Saskatchewan River	157,000
Red River	110,000
Local Tributaries	60,000
Burntwood & Churchill (CRD) Watershed	115,000
Total Lower Nelson River Watershed (incl. Churchill River Diversion)	540,000

Since 1972, calculated and recorded inflows into Lake Winnipeg have fluctuated on an annual basis from 50% to 180% of the long term average/mean of 70,000 cfs. These represent about 70% of the total drainage system area, and about 67% of the total average annual flows on the lower Nelson River.

Because the Winnipeg River watershed contribution to total hydraulic generation output of 38% exceeds the contributions of the other watersheds, it is the most critical watershed for MH's hydraulic output.

The next largest contributor to hydraulic output is the Lake Winnipeg local drainage system, which includes Lake Manitoba/Lake Winnipegosis, with a combined surface area of 14,000 sq. mi. plus direct inflow from gauged and ungauged tributary streams. On average, this watershed accounts for another 24% of MH's hydraulic output. Seasonable run-off predictions are further complicated by the limited number of smaller stream gauging stations currently in use.

Both of the above watersheds tend to experience the same ups and downs of flows, as they typically experience the same weather systems. A drought is likely to affect both.

The Red and Saskatchewan River watersheds, respectively, account for 22% and 32% of watershed areas and 7% and 14% of MH's average annual hydraulic generation output. With 23% of the total watershed area, the Churchill River Diversion (CRD) and the Burntwood River account for 17% of MH's total average annual hydraulic generation.

While MH manages its hydraulic resources on an overall watershed basis, the foregoing suggests a more focused approach on the Winnipeg River and local Lake Winnipeg watershed have merit.

The Winnipeg River watershed is already well-monitored and controlled. This allows for reasonable spring run-off predictions. However, the local Lake Winnipeg watershed would require the resumption/expansion of tributary flow gauging stations, and a considerable effort to track net precipitation-/evaporation (as it occurs) for purposes of predicting Lake Winnipeg water levels.

15.1.2 Hydraulic Generation Output History

Since the implementation of Lake Winnipeg regulation and the construction of the Churchill River Diversion, MH has experienced cyclical variability of both river flows and hydraulic generation. There have been extended periods of low flow, as experienced from 1980/81 to 1984/85 and again from 1987/88 to 1991/1992. Most recently, an extended period of mostly high flows started in 1996/97 and continued to 2010/11 (a period that includes the drought of 2002-2004).

Since the construction of Limestone G.S., total annual watershed flows and hydraulic generation output have averaged 115,000 CFS (3,230 m^3/s) and 29,000 GWh. During that period, the minimum annual Lower Nelson River flow of 76,000 CFS (2,160 m^3/s) and the minimum annual hydraulic generation of 18,500 GWh occurred in 2003/04. The highest annual hydraulic generation of 37,200 GWh occurred in 2005/06, with an annual Lower Nelson River flow of 180,000 CFS (5100 m^3/s). It is noteworthy that flows above 150,000 CFS (4300 m^3/s) are, essentially, spilled without producing additional hydraulic output.

Over the last 19 years, MH's hydraulic output has been

- above 30,000 GWh in 11 years;
- 27,500 to 39,000 GWh in 7 years; and
- below 27,500 GWh in 1 year.

In the preceding 14 years, the hydraulic output was:

- above 30,000 GWh in 5 years;
- 27,500 to 30,000 in 1 year; and
- below 27,500 GWh in 9 years (8 years below 25,500 GWh).

While high flow years can be associated with flooding, hydraulic output above 30,000 GWh essentially ensures favourable export sales (assuming "normal" pricing – which has not been the case since the credit crisis and recession of 2008/09). The important question is: how long can above average flows be expected to continue?

Revisiting the 100 years of recorded flows into MH's overall watershed suggests that extended periods (up to 2 decades) of average and above-average flows are unprecedented. Historical experience does not preclude an extended (12 of 14 years) low flow period, as occurred from 1929/30 to 1942/43.

MH indicates that after deducting a 500 MW reserve capacity, Bipole I and Bipole II could, theoretically, transmit up to 29,400 GWh of energy per year to the common bus -

this exceeds the existing Lower Nelson River maximum achievable output of 26,100 GWh.

15.1.3 More Conservative Hydraulic Operations

In recent years, MH has been faced with high reservoir levels and the necessity of spilling water. Conserving water as energy-in-storage does not have the appeal it usually does in some years. And, provision must be made for sudden reversals in water flow conditions, such as occurred in 2002/03, 2003/04 and 2006/07.

With domestic energy requirements now exceeding dependable hydraulic generation, the risk of excessive summer demand rises. A consideration of minimum energy-in-storage levels was recommended by the independent consultants, Drs. Kubursi and Magee.

15.1.4 Supply Constraints on Lower Nelson River Generation

MH's energy supply is currently not constrained by transmission capabilities within Manitoba. The existing Lower Nelson River plants are adequately served by Bipole I and II transmission, even in high-flow years.

However, this could change if Keeyask G.S. were to proceed without or in advance of Bipole III. MH contends that without Bipole III, the full output of Keeyask and the existing Lower Nelson generations could not be transmitted to the Southern Common Bus. Bipole I and II, with an upper transmission capability of 29,400 GWh, could transmit up to 80% of the upper limit of achievable annual hydraulic generation of 32,000 GWh from a constructed Keeyask and from the three existing Lower Nelson plants. MH disagrees with the use of an energy comparison and "looks" only to the installed capacity in defining the potential shortfalls of Bipole I and II.

15.2.0 NON-HYDRAULIC RESOURCES

15.2.1 Thermal Generation

MH's present thermal (non-renewable) resources are as follows:

- Brandon coal plant – 105 MW with a maximum output of 811 GWh/year (now available to meet a drought but expected to be decommissioned in 2018/19 for environmental reasons);

- Brandon SCCTs – 298 MW with a 2,350 GWh maximum output (generally not price competitive with imports); and

- Selkirk natural gas – 132 MW with a 953 GWh maximum output (again, generally not price competitive with imports).

The thermal resources have value as a dependable energy resource, but their limited availability because of either environmental or economic reasons contributes to MH's risk when the Utility sells energy in excess of hydraulic generation. Additional imports, beyond diversity imports, are likely to be substituted for MH's thermal production in almost all years, going forward.

15.2.2 Wind Generation

Post-2010/11, MH will have 236 MW of contracted wind energy with an estimated average annual output of 700 GWh. This equates to about a 35% on-line factor (the wind does not always blow).

With current average opportunity export prices consistently being below 3¢/kWh, MH may not see a positive revenue stream from its committed wind energy purchases from the Manitoba suppliers for many years.

15.3.0 DEMAND SIDE MANAGEMENT

MH's DSM programs are intended to provide an economical energy resource, one that either reduces imports (which represents coal or gas-fired generation) or increases exports. These programs were last evaluated at various times when the marginal cost of electricity, as defined by opportunity (spot) export prices, was upwards of 5¢/kWh. Going forward, with average opportunity export prices under 3¢/kWh, some of these programs may no longer be cost-effective, although they continue to have environmental value.

15.4.0 IMPORTS

MH typically expects to import some energy from its American utility counterparties in order to maximize its export sales, not only to American utilities but also to Ontario and Saskatchewan. The imports may be linked to firm contract provisions under Export Contract Agreements, or be non-firm and sourced from the MISO market. The price of imported energy is either that established for firm imports or tied to spot MISO market prices.

Other than in apprehended or actual drought situations, MH reports that it does not depend on imports.

15.5.0 TOTAL DEPENDABLE ENERGY SUPPLY

MH's Power Resource Plans (PRP) tend to use the total of its dependable energy (from hydraulic, thermal, wind, DSM and imports) to derive an approximate limit for the Utility's firm energy obligations. The aggregate of non-hydraulic generation resources (thermal, wind, DSM and imports) over the next 6 years will be in the annual range of 8,000 to 9,000 GWh.

Were MH to actually "sell" the 8,000-9,000 GWh of non-hydraulic resources in dependable or low-flow conditions, a significant revenue shortfall would likely arise.

Even if MH relied primarily on spot-priced imports, the marginal revenue could still be negative.

15.6.0 INTERVENER POSITIONS

Interveners did not focus on hydraulic resource planning.

15.7.0 BOARD FINDINGS

In section 4.8.0 the Board has already recommended that alternative development plans be considered, including CCCT natural gas thermal generation. MH's supply system seems to lack diversity, which could mean that it is overly exposed to drought risk. With CCCT generation, domestic production could replace potentially higher priced imports in either a drought or the rare occasion that one or both of the Bipole lines were down.

16.0.0 CARBON TRADING IN MH'S MARKETS

16.1.0 RENEWABLE ENERGY MANDATES

Within the MISO region, as across North America, the previous prospects for a substantial carbon tax or a cap-and-trade system that would be beneficial to MH and its hydro-based generation appear to have, at least until the economy has fully recovered, largely evaporated. One sign of this new reality is that the Chicago Climate Exchange market has been closed.

The focus of American utilities in the MISO region is now, as it has been in the past, on providing minimum-cost and reliable energy, with environmental attributes ignored except as mandated under renewable energy targets.

Various states, including Minnesota and Wisconsin, have renewable mandates that range up to a requirement that 25% of generation must be from renewables. This has led to a rapid expansion of wind generation within the MISO region. The sudden expansion in wind resources is in large part related to the ability of utilities to typically pass through the capital recovery costs directly to ratepayers, assisted by a 1.7¢/kWh federal U.S. Government subsidy on all wind energy generated. To qualify as renewable energy for MISO purposes, hydroelectric power generated by MH must come from new "small hydro" facilities. Specifically, Wisconsin would accept power imports from MH's 200 MW Wuskwatim project, while Minnesota presently has a cap of 50 or 100 MW to define new "small hydro".

MH has advised that its new (or pending) sales contracts with American counterparties transfer any "environmental attribute" associated with renewal hydro generation to the importer.

The very competitive wind energy now in place within the MISO market (24,000 GWh in 2010, up from only 3,000 GWh in 2008) constrains the limits of MH exports. It appears that back-stopping wind (wind power is not available about 65% of the time) in peak and off-peak periods or out-bidding CCCT natural gas generation during peak periods represent MH's most likely prospects in the export opportunity sales market.

16.2.0 CARBON CREDITS WITHIN FIRM CONTRACTS

MH's hydraulic energy is generally acknowledged to have a very low carbon footprint. Compared to coal-fired and natural gas thermal generation, CO_2 emissions can be almost negligible for run-of-the-river hydro plants.

Within MH's primary MISO market area, many states do not accept large hydro generation (greater than 50 to 100 MW) as qualifying for renewable energy credits. This does not preclude MISO utilities from claiming CO_2 emissions reductions for imported hydraulic energy for "public relations" purposes.

Currently, it is the Board's understanding that MH's MISO region customers are not willing to pay a premium for MH's "clean" renewable power. Instead, MH is faced with offering free carbon credits for at least the bulk of its exports (non-firm as well as firm).

The "free" inclusion of carbon credits in export sales may, at times, be compounded by MH's regular use of imports from thermal generation to either support its export sales or replace lost hydro generation in drought conditions. When MH employs lower cost off-peak imports, the probable source is coal-fired generation, which has twice the emissions than natural gas generation.

16.3.0 INTERVENER POSITIONS

Because RCM/TREE's view is globally oriented, for RCM/TREE MH's potential negative position with respect to giving up any environmental attributes attached to its "clean" exports to the purchaser is of no immediate concern. MH's clean energy is beneficial globally, as it likely displaces fossil fuel-based electricity.

Other Interveners did not take a position on this issue.

16.4.0 BOARD FINDINGS

The Board notes that MISO currently does not recognize MH’s clean energy as a distinct product with a higher market value than regular energy. As such, MH is currently not realizing any premium from the fact that its electricity is generated hydraulically.

17.0.0 DEMAND SIDE MANAGEMENT

11.1.0 GENERAL

MH's Demand Side Management (DSM) initiative, "Power Smart", consists of energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. The most current plan is the 2010 Power Smart Plan, which was filed during this hearing.

For electric operations, the initiative plays an important role in the Corporation's overall integrated resource plan. DSM initiatives assist customers in meeting their energy needs through energy-efficiency measures. Such initiatives enable MH to serve domestic customers with less energy. Reduced domestic load requirements allow for either reduced or deferred capital expenditures or increased energy exports.

17.1.0 PROGRAM EVALUATION

To evaluate new programs, a high level assessment (Marginal Resource Cost Screen) compares the expected benefits to the incremental capital costs. If a program passes the initial screening, a more detailed assessment is undertaken, which involves developing program concepts and designs and projecting costs and benefits.

MH determines the cost effectiveness of DSM programs using the Total Resource Cost (TRC) and Rate Impact Measure (RIM) Tests. The primary economic indicator for evaluating the effectiveness of both electricity and natural gas incentive-based programs is the TRC test. TRC measures the cost-effectiveness of a product or program, and a TRC benefit/cost ratio greater than one (>1.0) indicates that a program is cost-effective.

The secondary economic indicator for evaluating the effectiveness of programs is the RIM test. RIM indicates the cost effectiveness of a program from the Utility's perspective. All DSM-related savings and costs incurred by the Utility, including revenue loss and incentive payments, affect the RIM benefit/cost ratio. The results provide an indication of a program's expected long-term impact on rates.

As a guideline, MH attempts to design electricity-based DSM programs that have a RIM of 1.0 or greater. However, a program with a RIM of less than 1.0 may result in a program redesign, and may still proceed if the program is judged to provide overall benefits.

Established DSM programs are evaluated to determine the net program load savings and costs as well as the cost-effectiveness of the savings. Net savings take into consideration factors such as free riders (benefits derived that carry no specific cost), interactive effects of heating and cooling, as well as system peak coincidence and persistence effects. Customer data and market information are used to assess the impacts of these factors on the overall savings attributable to incentive-based Power Smart programs.

MH employs the Present Value of marginal benefits in three of their cost-effectiveness tests, namely the MRC (Marginal Resource Cost), TRC and RIM. These marginal benefits include revenues realized by MH from conserved electricity being sold in the export market, avoided cost of new infrastructure (e.g. transmission facilities) and measurable non-energy benefits (e.g. water savings). MH has yet to define the specific marginal benefits (or marginal cost savings) employed in the Utility's DSM evaluation process. At prior hearings, MH indicated that the energy value for DSM initiatives was primarily derived from the export market price. Energy value could alternatively be derived from the avoided cost of new infrastructure (generation or transmission). During the PUB's earlier EIIR hearing, MH suggested a proxy value for DSM energy savings (one related to the firm peak export energy prices of about 6¢/kWh) in lieu of defining the actual energy value (deemed to be commercially sensitive and confidential).

MH's most recent IFFs do not acknowledge that the export prices for energy have dropped substantially.

In evaluating DSM programs, MH attributes no value to delayed generation in its TRC test, nor does it consider the full benefit of displacing carbon in export markets.

17.2.0 PROGRAM COSTS AND AMORTIZATION

According to MH's 2010 Power Smart Plan, the Corporation forecasts spending $414.2 million over the next 15 years (through 2024/25) on DSM expenditures, including $23.2 million to be drawn from the Affordable Energy Fund (a fund established by legislation following the peak export price year, during which natural gas prices spiked).

Cumulative spending on electric DSM from 1989 to 2024/25 is projected to be $747.3 million. MH reported that it had budgeted to spend $37.8 million in fiscal 2011 and $38.8 million in fiscal 2012 on DSM initiatives.

MH amortizes its DSM costs over a 10-year period. This approach is similar to other Crown power utilities in BC and Québec. While the deferral of DSM costs, for subsequent amortization, is not allowed under new IFRS accounting standards, the approach can be maintained for rate-setting purposes.

MH's unamortized balance of DSM expenditures was $17 million as of March 31, 1994, and is forecast to grow to $214.2 million by 2011/12. The amortization of DSM expenditures was $978,000 in fiscal 1993/94, and is forecast to increase to $24.8 million in 2011 and $28.7 million in fiscal 2012.

The IFRS requirement will require MH to write off to retained earnings the unamortized balance of DSM expenditures in MH's 2011/12 fiscal year (the forecast balance to be written off is $214.2 million). MH has stated that the IFRS requirement to annually expense DSM expenditures rather than defer and amortize those costs will have very little rate impact.

17.3.0 DSM PROGRAM SAVINGS

According to MH's 2008-2009 Power Smart Annual Review, by the end of 2008/09 MH's Power Smart Programs would have achieved an annual load reduction of 1,510 GWh in energy, and the equivalent of a 406 MW reduction in winter peak demand. This level of "saved power" was reported by MH to represent an annual reduction of approximately $46 million in electricity customer bills (with a cumulative savings for customers of $352 million since the inception of the program).

MH reports indirect greenhouse gas emission reductions of approximately 1,019,000 tonnes of carbon dioxide equivalent emissions (plus 70,000 tonnes related to Natural Gas DSM programs).

In theory, domestic energy reductions through DSM initiatives contribute to the development of surplus generation capacity, which in turn contributes to the level of energy sales in the export market. In practice, additional export sales cannot always be made and MH has "spilled" water when the maximum capacity of its generating stations has been reached and storage cannot be increased due to lake regulation provisions. Furthermore, if export prices are below domestic rates, which has been the case since the 2008/09 credit crisis and recession, there is a negative revenue impact on MH from successful DSM initiatives. This negative revenue development does not reduce the environmental values of DSM, as DSM programs help instill a conservation mentality amongst MH's customers.

The cumulative energy and demand reduction achieved (including savings to date) through the Corporation's DSM efforts was forecast to achieve 3,048 GWh/year of energy savings and 915 MW of Winter Demand by 2023/24. These targets represent the expected impact of electricity efficiency codes and standards, customer service initiatives and incentive-based program activities. MH noted that the majority of the savings are to be realized from MH's incentive-based programs.

17.4.0 CITY OF WINNIPEG DSM PROGRAM

As a condition of MH's acquisition of Winnipeg Hydro, MH and the City of Winnipeg entered into a Power Smart Agreement on September 3, 2002. The objective was to capture energy efficient opportunities within the City's facilities, with a minimum target of reducing the City's energy bill by $800,000 annually. MH guaranteed the City an annual savings of $800,000 from the measures. If the savings were not met, MH was required to make a payment for the balance. The ten-year agreement includes a total savings commitment of $8.8 million.

MH has actually invested $10.6 million into DSM measures under the agreement. This includes $3.2 million in "commitment" payments, $6.4 million in energy efficiency project costs and $1.0 million in program administration and management fees.

MH stated that due to the energy savings realized from the initiatives undertaken, MH will be economically better off, as the energy saved is available for export.

17.5.0 CARBON TRADING

In 2002, MH became a founding member of the Chicago Climate Exchange (CCX). CCX required participants to reduce emissions relative to historic baselines. Each participant was provided an annual allowance of CCX units, which decreased each year from the historic baseline. If a participant's emissions exceeded the participant's allowance, the participant was required to buy additional units through the exchange. Conversely, if their emissions were below their allowance, they were able to sell the surplus units.

The CCX market permanently closed on December 31, 2010. An active carbon trading regime has not materialized. Without carbon legislation in the U.S. jurisdictions into which MH exports, coal-fired electricity generation remains the least-cost base load option for most American utilities.

17.6.0 LOWER INCOME DSM PROGRAM

In its 2006 Power Smart Plan, MH introduced a new residential program, the "Hard To Reach" (HTR) program. The HTR program targets lower income residential households on an integrated basis (i.e. for both natural gas and electric consumption). The program has since been modified into the Lower Income Energy Efficiency Program (LIEEP), which leverages MH's Power Smart programs, the Affordable Energy Fund (AEF), the Federal Government ecoENERGY Program, provincial government programs and existing community-based infrastructure.

The objective of LIEEP is to ensure that the financial benefits associated with implementing Power Smart energy efficiency measures will be realized by low income consumers. The program targets both lower income Manitoban homeowners and tenants. MH provided an update during the hearing, which indicated that participation of electric households in the LIEEP through 2010/11 totalled 720 households.

Rental buildings for which the landlord pays the energy bills are not eligible for participation in the LIEEP, as the landlord would be realizing the benefits of lower energy bills rather than the low income tenant. In the case of lower income tenants who do pay energy bills, an agreement must be reached between MH and the landlord or building owner to ensure that a substantial portion of the benefits associated with retrofit measures funded by MH's program will be passed on to tenants.

Non-profit social housing organizations, including the Manitoba Housing Authority (MHA) and other non-profit subsidized housing organizations, are eligible to participate in the program. An agreement has been reached between MH and MHA, whereby MHA will pay the AEF portion of the cost of the upgrades in cases where the tenant is not directly paying the energy bill.

Eligibility for households pursuant to the program was established by the Corporation at 125% of the Low Income Cut-Off (LICO) established by Statistics Canada. MH undertook a 2009 residential survey which indicated that 74,938 households meet the LICO standard and 105,784 households meet the LICO-125 criteria.

Targeted measures to be addressed by the program include:

- low or no-cost basic energy efficiency measures, such as compact fluorescent lights;
- faucet aerators, low-flow showerhead, pipe wrap, hot water tank set-back, and caulking/air-sealing;
- insulation for basement, attic and crawlspace installations; and
- high-efficiency natural gas furnaces.

MH intends to deliver the program through both Community Based Organizations (CBO) and individual household participation. Both approaches require pre- and post-completion audits to identify energy efficiency opportunities and verify that the work was completed.

17.7.0 HOME ENERGY BURDEN

Home energy burden represents energy bills as a percentage of household income.

The concept of the customers' "energy burden" is not employed in the design or assessment of MH's affordable energy programs. MH's stated position is that issues surrounding affordability are outside the scope of MH's mandate and is a matter of policy for legislators and government agencies responsible for these issues.

Since the commencement of LIEEP in 2005/06 through to 2009/10, MH has spent $1.9 million on electric LIEEP, including $0.7 million from Power Smart and $1.2 million from the AEF. MH had forecast to spend $3.8 million in 2009/10 on electric LIEEP, including $3.2 million from the AEF, but only spent $0.5 million in total including $0.4 million from the AEF. MH attributed the $3.3 million shortfall to low participation levels in the program.

17.8.0 THE AFFORDABLE ENERGY FUND (AEF)

Following a spike in oil and natural gas prices in the summer and fall of 2005 on the heels of hurricanes Katrina and Rita, which damaged energy availability from south-east American production and distribution sites, and also following the Board's action on November 1, 2005 when it deferred costs and restrained natural gas rates for Centra Gas' residential customers to recognize what the Board deemed to be a price spike, the Province of Manitoba introduced *The Winter Heating Cost Control Act*, which was subsequently passed, proclaimed and implemented in 2006. Among other provisions, the Act established the Affordable Energy Fund (AEF), requiring MH to contribute 5.5% of its fiscal 2006/07 gross export revenues to the AEF. This resulted in a fund of $35 million to be utilized for various energy efficiency initiatives which were to primarily assist low-income electricity and natural gas customers.

MH indicated that $19 million of the AEF's $36.8 million was earmarked for province-wide low-income initiatives. MH indicated its intention that the $19 million reserved for low-income programs would mostly benefit electricity and natural gas space-heated homes, and would provide for programs that would not otherwise be funded from MH/Centra's rate-based DSM programs.

A breakdown of the allocation of the AEF and the spending to 2009/10 is as follows:

Projects	Allocated	Actuals to December 31, 2010
Low – Income / Community Based Initiative	**$19.0**	**$5.1**
Geothermal Support	**$6.0**	**$1.4**
Community Energy Development	**$8.0**	**$0.8**
Oil and Propane Heated Residential Homes	**$0.25**	**$0.2**
Residential Energy Assessment Service	$0.5	$0.5

Oil and Propane Furnace Replacement	$0.2	$0.1
Residential Solar Water Heating Program	$0.3	$0.3
Power Smart Residential Loan	$1.2	$1.2
Unallocated Interest Accruals	$0.6	-
Special Projects	**$2.8**	**$2.0**
Total	**$36.8**	**$9.7**

17.9.0 FIRST NATIONS/ DIESEL COMMUNITIES

MH has employed a dedicated team and partnership approach to pursue energy efficiency opportunities in First Nations communities. The approach includes identification of ten homes in the community for which an initial home audit will be conducted. MH then trains First Nations members to undertake required retrofits, supplies the materials, and assists the First Nations in obtaining any Federal government ecoEnergy grant programs funds that may be available.

MH reported that it had completed work on 10 homes on two First Nations communities, and was shipping material to retrofit 15 homes in three other communities. It was also working with other communities, including communities served by diesel generated electricity, to see if they were interested in participating in the program.

17.10.0 DSM PROGRAM EVALUATION

MH contracted Phillipe Dunsky to undertake a Power Smart Portfolio Review. Mr. Dunsky made several recommendations to reinvigorate and expand the DSM program of MH. Some of the recommendations were to close program gaps by creating and expanding programs for:

- multifamily residential housing;
- manufactured new homes;
- consumer electronics and office equipment;

- appliance retirement;
- new commercial construction; and
- commercial custom retrofit.

MH has acted on many of the above initiatives by expanding its program offerings, including, among others, the development of a Refrigerator Recycling Program and a Commercial New Buildings Program.

Mr. Dunsky also recommended that MH:

- provide market training in the residential sector, beginning with the review of opportunities and needs for all programs;
- utilize upstream incentives in both residential and commercial/industrial sectors, beginning with the comprehensive review of the potential for upstream incentives in all programs; and
- consider options for encouraging limited third-party ideas or implementation. MH should evaluate the effectiveness of variety of options for encouraging innovation within the Province. Third-party set-asides such as those in California and Minnesota were one option to consider.

MH cited several examples where it has sought collaboration with third parties to deliver programs and where it intends to continue to pursue third-party collaboration whenever the option is assessed to be the most efficient and effective.

MH did not agree with establishing third-party set-asides as being an effective and efficient strategy for achieving the Corporation's energy-efficiency objectives. It thought that such an approach could lead to implementing some programs in a more costly manner and simply spending the set-aside funds as opposed to undertaking initiatives in a more cost-effective manner.

Mr. Dunsky also recommended that MH establish aggressive energy savings targets such as 1 to 2% per year, in line with those of leading regions. In response to this recommendation, MH agrees with establishing aggressive energy conservation targets. However, MH believes that it is more appropriate to base the targets on identifiable economic potential for achieving energy savings rather than basing targets on arbitrary percentages. MH indicated that it is going to undertake a market potential study to identify current energy savings potential remaining in the province and will conduct a detailed comparison of MH's Power Smart Plan to BC Hydro's Power Smart plan to assess potential gaps in targeted energy savings.

Mr. Dunsky also recommended that DSM programs should be screened by the Program Administrator Cost Test (PACT), Total Resource Cost (TRC) or Societal Cost Test (SCT). Mr. Dunksy stated that the RIM test is likely leading to lost opportunities. At the last GRA, Mr. Dunsky opined that the RIM test should not be utilized to screen for justification of DSM programs. While TRC should remain the primary test for DSM programs, under MH’s current approach there will be proposed measures that will fail the TRC test that should still be pursued if they pass the “utility cost” test. The utility cost test compares money invested in a program with the value of expected energy savings for the utility. If MH can generate cost-effective kWh savings, the program initiative should proceed. In his review of the Power Smart Program, Mr. Dunsky urged MH to reconsider its screening process as a whole to ensure that it is in line with common leading practices.

MH did not agree with this recommendation. MH uses a number of cost effectiveness tests to assess energy efficiency opportunities, preferring to use the Levellized Utilities Cost test rather than PACT. MH also stated that it uses a more inclusive version of the TRC than the SCT, and also considers various qualitative factors including equity (e.g., reasonable participation by various ratepayer sectors) and overall contribution towards having a balanced energy conservation strategy and plan. MH also disagreed that the use of the RIM test was restricting its ability to pursue energy efficiency opportunities.

Lastly, Mr. Dunsky recommended that MH

- screen alternative program designs for total program cost effectiveness;
- reconsider its screening process as a whole to ensure it is in line with common and leading practices; and
- consider an expert-supported stakeholder advisory group in which stakeholders are funded supported by independent experts in a non-adversarial setting.

MH stated that stakeholder meetings to share policy and conceptual information provide some value but that such a process proves to be ineffective for establishing detailed program designs, which involve specific marketing concepts, product delivery channels, and undertaking complicated computer assessments to provide program metrics. MH further does not support the recommendation for funding external consultants for stakeholders, as this would result in a duplication of resources and be a very costly approach. MH stated that the regulatory process allows for a reasonable amount of oversight with respect to MH's DSM programs through the hiring of consultants, and that the extent of this investment is already controlled through the regulatory process.

17.11.0 INTERVENER POSITIONS

17.11.1 CAC/MSOS

DSM Program

CAC/MSOS acknowledged that MH's staff involved with DSM has a commitment to energy demand reductions and that the Corporation has a historical reputation in offering strong programming within the Canadian context. However, CAC/MSOS holds that MH attributes savings to some of its residential plans which are more optimistic than those adopted by other well-respected bodies in the area of energy efficiency (such as the Ontario Power Authority).

CAC/MSOS urged the Board to make a finding that the Power Smart residential incentive-based programs are lagging relative to the plan as a whole, with a major factor being low participation rates. CAC/MSOS noted that the low participation rate was most evident in the LIEEP and the low spending from the AEF.

CAC/MSOS recommended the Board accept the evidence of Mr. Chernick, who concluded that the 2009 and 2010 DSM plans appeared to be deficient insofar as they involve spending less and aiming lower in terms of their savings targets and spending targets compared to previous levels. For CAC/MSOS, MH's DSM program has not demonstrated a commitment to maximizing benefits for consumers.

CAC/MSOS accepted the conclusion of Mr. Dunsky that MH will need to be more ambitious with its electricity savings goals and should reconsider its current portfolio of programs and strategies to maximize energy efficiency. CAC/MSOS recommended that the Board make a finding that given the poor performance of the 2009/2010 Power Smart Plan, there is a demonstrated need to make major changes in the DSM program.

CAC/MSOS further urged the Board to determine that there is a broader need for independent third-party audit of Power Smart. MH should be required to consult with the Board and interested interveners prior to finalizing the terms of such a review.

Low Income Programs

Of particular concern to CAC/MSOS is the low participation rate in the LIEEP and the low spending of the AEF. CAC/MSOS recommended that the Board find that the challenges faced by the LIEEP suggest the need for a strategic review of the program to be provided by an independent third party who would undertake an evaluation and audit of MH's operations, to be filed with the next GRA. CAC/MSOS recommended that MH, prior to undertaking the review, consult with stakeholders as well as the Board to finalize its scope.

Dr. Tom Carter appeared on behalf of CAC/MSOS and spoke to issues related to energy poverty and low income rate affordability in Manitoba. Dr. Carter listed four approaches to energy poverty:

- the demand-side approach, where funds, loans, or grants are provided to households so they can purchase more energy efficient appliances or retrofit or weatherize their homes;
- the supply-side approach, where direct payments or subsidies are made to households to increase their income to help them cover the cost of energy;
- the bill management approach, which may involve the negotiation of late payment charges, a plan to pay down arrears, equalized payment plans, or forgiveness plans; and
- the regulatory requirements and frameworks that are set in place.

CAC/MSOS submitted that the problems of energy affordability facing low income Manitoba residents have severe social, economic, and business consequences that permeate throughout all sectors of the province. From a social perspective, unaffordable home energy not only threatens the ability of low income customers to maintain access to their utility service, but also imposes a range of adverse consequences threatening the health, housing, and general welfare of those households. Unaffordable home energy bills mean that low income Manitoba residents will go without food, medical care or other life necessities.

Dr. Carter stated that addressing the energy affordability of low income homes will generate positive social benefits. It will improve public health and safety and bolster the competitiveness of local business and industry. It will also reduce the cost of non-payment and improve the efficiency and effectiveness of utility collection efforts.

Demand and supply-side programs, according to Dr. Carter, can help reduce the cost of credit collection, bad debts, as well as termination and reconstruction costs for the utility.

In spite of the positive aspects of these programs, Dr. Carter does not think they are sufficient to make much of a difference when it comes to poverty alleviation, and states that these programs are not integrated with other programs that should help address the long-term and systemic causes of poverty.

In reviewing U.S. bill assistance programs, Dr. Carter noted particular challenges associated with the delivery of energy poverty programming, with the biggest problem being the low participation rate of many of these programs. Other challenges include difficulty in identifying the working poor, high mobility rates, the apprehension and suspicion about dealing with government, and the fact that people in poverty are so occupied with everyday existence that they cannot devote the time to avail themselves of these programs.

Dr. Carter stated that low participation rates create real problems with respect to horizontal equity. In particular, if programs are paid for through charges to the ratepayers of the utility, there is a subgroup of people that is eligible for the programs but does not avail themselves of them, yet has to help pay for the programs for the other subgroup that does use them.

In general, Dr. Carter suggested that MH was not as well-placed as some other departments in government to deliver energy affordability alleviation programs or poverty alleviation programs in general.

Dr. Carter indicated that utilities are not the best source of broad strategic poverty alleviation policies. These policies are the mandate of government, which has to build a package on the basic planks that government has in place to deal with poverty. To be effective, programs have to be integrated as part of a broad strategy that includes money for education, money for skills development, and programs to get people back in the workforce. According to Dr. Carter, the integrated approach that is currently in place fails in large degree because the levels of assistance under Social Assistance and minimum wage do not ensure that households have a level of income that will provide them with a good quality of life and opportunities to improve their potential in society. Energy poverty alleviation programs are not sufficient. Although such programs serve an important role, they should not be considered as poverty alleviation vehicles because they are not long-term, do not provide deep levels of assistance, and are not integrated with other program vehicles.

Dr. Carter stated that there are three sides to the energy poverty equation, these being price stability, energy efficiency and income stability. CAC/MSOS submitted that the best way to assist all vulnerable consumers through the regulatory process is to insist upon ongoing prudence in the operations of MH in order assist MH to achieve just and reasonable rates and invest significantly in low income energy efficiency.

CAC/MSOS endorsed recommendations made by RCM/TREE's witness Mr. Colton that MH adopt a crisis intervention and arrears management program, while rejecting Mr. Colton's recommendation for a Low Income Rate Assistance Plan. In objecting to the Low Income Rate Assistance Plan recommended by Mr. Colton, CAC/MSOS cited several concerns, including that:

- the program is unlikely to assist the poorest of the poor, as those individuals on income assistance are already receiving help with respect to their utility bills;
- the program's participation targets will not be met;
- the program runs the risk of a diverting scarce resources away from other programming such as LIEEP; and
- in light of low participation rates, they program would be horizontally inequitable.

CAC/MSOS also raised the question of the Board's jurisdiction to impose such a program given Manitoba's statutory framework.

17.11.2 MIPUG

Low-income programs

MIPUG has no issue with any bill assistance program that is funded on a voluntary basis. To do otherwise would be, in MIPUG's view, discriminatory. MIPUG noted that unless there is 100% participation in the low-income programs, the low-income customers that do not participate in the program indirectly get penalized.

With respect to the role of MH in low income programming, MIPUG cited Dr. Carter, who suggested that MH participate in an integrated strategy but not a funder of programs to alleviate poverty.

17.11.3 RCM/TREE

DSM Programs

RCM/TREE adopted the evidence of Mr. Paul Chernick. RCM/TREE acknowledged the excellent work on DSM efforts made by MH in the past. RCM/TREE approves of the recently unveiled refrigerator program and the efforts being made in the First Nation communities served by diesel generation. RCM/TREE expressed concern that MH is not planning to continue its DSM efforts as aggressively in the future.

RCM/TREE noted that Mr. Chernick had graphed MH's projected DSM savings to 2025, observing a precipitous decline in both DSM efforts and annual incremental savings. For Mr. Chernick, MH's DSM efforts are modest compared to those of many other North American jurisdictions. He noted that other jurisdictions target DSM energy savings of 1% to 2%, while MH's forecast begins at 0.6% and declines to 0.2%.

Also, when compared to other jurisdictions, for Mr. Chernick MH's spending on DSM per MWh was insufficient. Mr. Chernick concluded that MH should be able to double or triple its energy efficiency spending and savings from current levels and maintain such efforts throughout the planning period. RCM/TREE recommended that the Board benchmark its DSM programs to the programs of the three leading providers as identified by Mr. Dunsky, namely Pacific Gas and Electric (California), Efficiency Vermont and Xcel Energy Minnesota.

RCM/TREE also recommended that the Board establish DSM targets for MH to require the Corporation to increase its energy efficiency investments to reach the 90th percentile of North American jurisdictions, and that the RIM test be abandoned for program design screening.

RCM/TREE proposed that MH establish a link between DSM programs and Power Smart rates. RCM/TREE noted that rates and rate structures that fail to provide appropriate price signals undermine the performance of Power Smart DSM programs by offering contrary incentives that, in effect, subsidize higher consumption by applying embedded cost savings and export earnings volumetrically. If incremental use of electricity is underpriced, the true cost of growth imposed on other users, the utility, the province and the global environment is hidden and conservation and self-generation options become less cost-effective or suffer a longer payback period.

RCM/TREE cited past Board Orders which supported conservation incentives in rates and questioned the Board’s interim rate Order 40/11, which effectively eliminated the block differential for residential rates and provided no change to the basic charge. RCM/TREE noted that a reading of Order 40/11 illustrates a tight link between affordability goals, conservation goals and rate-setting. RCM/TREE submitted that MH's mandate to promote economy and efficiency in the end use of electricity cannot be adequately fulfilled without supportive Power Smart rate structures. RCM/TREE also stated that the energy system must mitigate the potential impacts of higher marginal rates on those customers who are least able to afford the energy. In summary, RCM/TREE submitted that MH cannot deliver on its mandate to provide its domestic customers with the benefits of electric power economically and efficiently unless it can also deliver effective measures to mitigate unaffordable energy burdens among its low income electricity customers.

RCM/TREE supports MH's initial proposal to reduce the Basic Monthly Charge by $2.00 over two years. RCM/TREE also supports Mr. Chernick's recommendation that the Board re-establish a rate inversion by making the tail-block 5% higher than the first block at the outset. In subsequent years, the first block should be reduced to no more than 600 kWh/month and the tail-block rate moved towards marginal costs. To mitigate the heating burden of existing electric heat customers, Mr. Chernick proposed offering a larger first block of lower cost energy in the winter months. The size of the first block would be set with the objective that the average heating and non-heating customers would end up paying the same blended energy rate over the two energy blocks.

RCM/TREE urged the Board to instruct MH to modify rates in the following ways over the next several years:

- increase tail block energy rates to marginal cost, including environmental costs;
- implement marginal cost-based rates for larger general service customers, using a two-part rate if necessary;
- use the increased revenues from tail block energy sales to reduce customer demand and fund enhanced energy-efficiency programs, low income customer discounts, and economic development, and improve MH's financial structure; and
- implement time-of-use energy charges, starting with the largest customers, and move revenue collection from demand charges to time-of-use energy charges.

RCM/TREE indicated that the implementation of these initiatives can take place at MH's next rate proceeding.

Low Income Programs

RCM/TREE submitted that MH should institute an affordability program as recommended by Roger Colton, who appeared on behalf of RCM/TREE. Mr. Colton stated that energy bills impose a substantial burden on low income households served by MH. Current home heating, cooling and electric bills in Manitoba have driven the home energy burdens for households living with incomes at or below 125% of LICO to crushing levels. Mr. Colton stated that the Board should be concerned when the energy burden of consumers exceeds 6% of household income. According to Mr. Colton, an affordable home energy burden is 6% of income as compared to a “severe” energy burden of 15%.

Dr. Colton proposed a four-part low income affordability program, consisting of :

1. A rate affordability component that brings the bills of low-income customers (LICO-125) within a range of affordability (6% of income) through offsetting credits. The annual credit is determined by first establishing a burden-based payment set at 6% of income. That amount is then compared to an estimate of the projected annual energy bill for the household. The credit would be based on the difference between the burden-based payment and the total projected annual energy costs. The credit would be applied to monthly energy bills and would be fixed to provide an incentive for conservation.

2. An “arrearage” management program, which retires a customer's arrears over three years in exchange for monthly contributions by the customer to his arrearage retirement. The program is designed to reduce pre-program arrears to a manageable level over an extended period of time. The customer earns credit towards the arrearage balance, so long as the customer remains on the affordable rate. The payment under the scheme is to be set at $5 per month or $60 per year to go towards the arrearage balance.

3. A crisis intervention component that addresses the income fragility of low income households. The crisis intervention component should not be based on income eligibility and should provide administering agencies with flexibility to distribute assistance on an as-needed emergency basis. The program should be limited in time and the funding should be distributed through existing crisis intervention programs.

4. An energy-efficiency component, similar to MH's LIEEP, with improved integration and other components and accelerated roll-out.

The cost of operations and administration of the first three components of the program should be recovered through meter charges and late fees. Mr. Colton estimated the cost of the proposed program to be \$44.2 million, including the provision of rate discounts sufficient to reduce energy burdens to no more than 6% for LICO–125 households. Mr. Colton provided a set of scenarios with differing program energy burden thresholds between 6% and 10%, with a cost ranging from \$24.9 million (10% energy burden threshold) to \$44.2 million (6% energy burden threshold).

RCM/TREE stated that the Board has a responsibility to consider the special circumstances of low-income ratepayers when deciding what is considered to be just and reasonable rates. It would be inappropriate for the Board to ignore energy poverty as described by Mr. Colton in determining just and reasonable rates. It would appear to be self-evident that what is a just and reasonable rate for a person living below the poverty line is different than it would be for a family, for example, that spends less than 2% of its household income on energy.

RCM/TREE cited the case of *Advocacy Centre for Tenants - Ontario v. Ontario Energy Board* 293 D.L.R. (4th) 686 as judicial authority that the PUB has the jurisdiction to order the implementation of the low-income energy affordability program.

17.12.0 BOARD FINDINGS

17.12.1 DSM Programs

The Board recognizes that MH has been making an increasingly significant investment in DSM programs.

The Board encourages MH to continue to pursue environmental objectives on an integrated natural gas-electricity basis, and, in particular, to consider the difficult position of low-income customers that may be increasingly faced with higher energy costs while too often lacking the funds, if not the know-how, to achieve needed upgrades that would reduce their energy bills and GHG emissions.

The Board, as stated in Order 116/08, remains of the view that MH's DSM focus should be four-fold:

- Environmental: Wasted energy and greenhouse gas emissions should be reduced in Manitoba and in the export markets, as climate change is a global challenge.

- Economic: Energy not consumed by Manitobans should be available for sale on the export markets, ideally during peak hours and at peak prices.

- Economic: Energy not consumed by Manitobans and not sold on the export market, either due to transmission capacity issues or unfavourable pricing, can assist in the deferral of new generation and transmission.

- Social: Increasing the energy efficiency of low-income households will allow more families to remain in their homes and to have more disposable income available for necessities other than energy. The total cost of energy (gasoline, natural gas, electricity, propane, etc.) has soared for all households, but the cost increases have been particularly devastating for households in the bottom four deciles of household income levels.

The Board continues to question the appropriateness of MH's current approach of deferring DSM costs and amortizing them over ten years, and notes that this approach will no longer be allowed under IFRS. IFRS will require DSM expenditures to be expensed in the period in which they are incurred. Actual DSM expenditures are currently forecast to be $37.8 million in 2010/11 and $38.8 in 2011/12 while amortization of DSM spending is forecast to be $24.8 million and $28.7 million respectively. The difference will have to be expensed under the current IFRS pronouncements, thus putting further pressure on rates.

The unamortized balance of DSM costs is forecast to grow to over $214 million by 2011/12. This amount will likely not meet the criteria of an asset under IFRS and will have to be written off against retained earnings. Nonetheless, the Board believes that the manner in which program expenses are accounted for should not change the manner in which MH evaluates DSM programs.

The Board notes the evidence of Mr. Dunsky, who provided recommendations to MH to improve its DSM program. The Board is encouraged that MH has listened to many of Mr. Dunsky's recommendations and has proposed program changes. The suggested changes put forward by Mr. Dunsky, including changing the economic screening test to the PACT, has merit and should be considered by MH in its design of current and new low-income programs. The Board shares the view that the current screening process may be resulting in some opportunities being missed. The Board would like to see expanded program delivery to assist in conservation.

17.12.2 DSM Program Evaluation

The Board notes that MH projects that by fiscal 2023/24 it will have achieved 3,048 GWh of DSM savings for its electricity operations. If achieved, this would represent a 200% increase in DSM energy saving over 12 years, representing a growth rate of almost 17% per year. Power savings are expected to reach 915 MW, an increase of 230% over 12 years or almost 19% per year.

There is projected to be a drop in savings in later years of the program. The Board shares the concerns raised by Mr. Chernick of a decline in both investment and savings. The Board suspects that the opportunity for further reductions is significant. However the Board also realizes that projections extending fifteen years into the future are highly subjective.

During the EIIR hearing in 2009, MH offered a proxy value (related to the firm peak export energy prices) of about 6¢/kWh for DSM calculation purposes in lieu of defining the actual energy value, which MH deemed to be commercially sensitive and confidential. The Board suspects that MH's marginal benefit value in the cost effectiveness tests set out above also employs a similar proxy value, and it is clear that MH's most recent IFFs do not yet acknowledge that the export prices for firm peak energy have dropped substantially in recent years. The actual 2009/10 price was 2.83¢/kWh for peak opportunity export sales. There is reason to believe that prices under 3¢/kWh may still be the reality for years to come.

In the current circumstances, where MH's generation and transmission expansion plans appear to be moving forward despite an unfavourable export market, the Board is concerned about the level of economic benefits to be achieved by MH's existing and new DSM initiatives. To export DSM energy savings at prices below domestic rates does not seem totally logical from a financial perspective.

17.12.3 Lower-Income Energy Efficiency Programs

The Board commends MH for the broadening of its low-income programs and the inclusion of programs specifically targeting First Nation communities. However, the Board is concerned at the slow pace of delivery on the programs and notes that with respect to the LIEEP and AEF, MH has struggled to meet budgeted spending targets to date.

The Board understands that MH is working on a tenant-focused LIEEP but has yet to implement it. The Board understands that there may be resistance for landlords to take part in the program due to split incentives and the low-cost business models under which many landlords operate. MH should make every reasonable effort to increase participation rates by eligible landlords, as this benefits both low-income tenants and the environment. The Board further believes the LIEEP should be subject to an external review to ensure that all opportunities are being adequately met. To that extent, the Board will expect MH to provide the Board and interested stakeholders with draft terms of reference for a program review.

Although MH is beginning to address the issue of energy poverty, more is required. The Board is very concerned with the slow pace of the overall energy poverty relief effort. MH indicated that the current program is anticipated to provide relief to only 1,700 low-income households by the end of 2010/11. The current low-income population in Manitoba seems to comprise at least 105,000 households, meaning the program only targets about 1.6% of potentially eligible households annually. The Board agrees with the views expressed by CAC/MSOS and RCM/TREE that more should be done.

As for the AEF, the Board notes that $1.4 million in interest has accrued on the balance in 2009/10, thereby allowing the AEF balance to grow. This additional amount can be used to fund further low-income programs. The Board recognizes that capacity issues may exist in program delivery. However, the material budget variances which have become apparent indicate that capacity constraints may not be the only obstacle. This, too, warrants an independent external review of the program.

Overall, the Board continues to remain concerned (as expressed in previous Board Orders) with the pace of delivery of low-income programs for the First Nation diesel communities. Although MH has reported progress with respect to First Nation programs as a whole, the progress made to date does not address the full extent of energy efficiency issues on First Nation communities. In particular, more needs to be done with respect to energy efficiency measures for the First Nation diesel communities, where energy costs are significantly higher than in communities connected to the grid. The Board urges MH to work together with First Nationals and Aboriginal Affairs and

Northern Development Canada to expedite the delivery of energy efficiency measures in remote communities.

Bill Assistance

The Board notes that the low-income energy burden is high in Manitoba. This was confirmed by the 2009 residential survey which indicates that now over 105,000 Manitoba households are considered low-income, falling into Statistics Canada's LICO-125 category. The Board further notes that a substantial portion of the LICO-125 group has an energy burden in excess of 9% of household income.

Currently, MH relies solely on a voluntary program to alleviate energy burden. The program, known as Neighbours Helping Neighbours and administered by the Salvation Army, allows MH customers to donate to an energy relief fund. From a program delivery perspective, the amount of money in the fund is inadequate. While it allows families and seniors who are unable to pay their natural gas or electricity bill due to personal hardship or crisis to receive support from the program, that support is only available if there is sufficient money in the fund.

In Manitoba, adequate energy for heating is a necessity of life. As such, it should be both abundantly available and affordable. Programs that reduce the energy burden faced by low-income customers and provide significant societal benefits would likely return dividends to the Province above the cost of delivering such a program. Those benefits would include lower health care costs and other benefits such as reduced debt write-offs, improved customer service and avoided reconnection costs borne by the utility.

Before the Board is prepared to require MH to develop a definitive bill assistance program along the lines of the program proposed by RCM/TREE, the Board needs further information as to existing funding made available by government and the programs available to directly or indirectly alleviate energy poverty.

The Board is firmly of the view that MH should participate in an integrated strategy with respect to low-income programs. This could, and likely would, include a defined role in education, promotion, monitoring and perhaps delivery of such a program in conjunction with CBOs. However, until the Board has additional information as general and specific government funding available, the Board is not in a position to determine whether MH should be a "funder of programs to alleviate poverty" as suggested by RCM/TREE.

18.0.0 RISK

Similar to other large corporations, MH faces risk issues daily. All facets of MH's operations contain risk. To the extent that risk cannot be avoided, it must be managed. In order to set itself up to withstand adverse events and demonstrate the Corporation's financial strength to rating agencies and lenders, MH established its target debt-to-equity ratio of 75:25 further discussed in section 12.1.0 of this Order. MH applies this target ratio at all times except for periods when major new investments are in process that have yet to be placed "in-service" and start generating income. The Board and the Interveners have supported the target ratio. While the Board has expressed some concerns about the composition of MH's equity, as set out in section 12.1.0 of this Order, MH has met its target as of March 31, 2011 based on its own definition of equity.

To provide greater certainty as to the quantum of the equity "cushion" being sufficient to withstand the risks faced by MH, the Board has long requested MH to provide an in-depth and independent study of all operational and business risks facing the Utility. The study was to be a thorough and quantified risk analysis that included the probabilities of all identified operational and business risks. To that extent, this GRA was expressly stated to include a review of MH's risks and risk management.

Unfortunately and disappointingly, MH failed to provide the quantified risk analysis sought by this Board. In the words of one of the interveners, it was an "opportunity wasted". Rather than provide the risk analysis sought, MH incurred external costs of approximately $4 million to embark on the production of a report and the employment of a legal strategy to rebut the allegations of a risk consultant previously retained but subsequently terminated by MH.

What follows is the Board's own assessment of various risk issues based on the extensive record before it.

18.1.0 DROUGHT RISK

18.1.1 Historical Droughts

Hydraulic generation accounts for 80% of MH's average annual energy output. MH relies on river water flows and lake levels as sources of hydraulic energy. Since MH relies so heavily on water power, drought is one of the greatest risks faced by the Corporation, especially when a drought extends for several years.

Historically there have been approximately seven periods when MH would, given current domestic and export commitments, have been faced with rather substantial energy supply shortfalls. That fact suggests a theory, worthy of being tested, that total reliance on hydraulic generation may not be in the best interests of MH's ratepayers. A system dominated by hydro generation but with a significant natural gas (CCCT) thermal component would, it appears, ameliorate drought impacts and their financial consequences.

18.1.2 Drought Frequency

MH contends that it is not possible or appropriate to calculate a frequency of recurrence of various drought events. Instead, MH chose to declare and employ 1936/37 to 1942/43 hydraulic conditions as its worst-case scenario and 1987/88 to 1991/92 hydraulic conditions as a basis to determine an appropriate drought reserve target.

Attempts by various consultants to define a frequency for droughts of a five-year duration ("five-year-drought") produced a variation of opinions but no specific recurrence period. Drs. Kubursi and Magee (KM) indicated a 1.35% frequency, which suggests that a five-year-drought should be expected to occur only once in 65 years. It can be reasonably argued that the actual drought events that were recorded over the last 100 years could reoccur in the next 100 years. With hydro-electric generating stations having a potential service life of 100 years or more, it is unrealistic to assume that future years will not include substantial droughts similar to those experienced in the past century.

More recently, MH has suggested a 2% frequency for a five-year-drought. As MH's retained earnings (hopefully) increase, these retained earnings could be annually tested against each of the historical drought periods. This would provide ongoing drought event coverage ratios which could be employed in evaluating potential long-term contract commitments. MH's five-year-drought scenario could be treated as a baseline for comparison purposes.

18.1.3 Supply Commitments

When hydraulic generation in a given year exceeds committed domestic load, surplus energy is available for export sales. Over the last decade, MH has looked to long-term and annual short-term firm export contracts for the sale of surplus energy totalling approximately 6,000 GWh per year. MH's total annual commitment between domestic load and firm export sales has typically been in excess of the minimum annual dependable energy level of 21,000 GWh, with a key assumption that other non-hydraulic resources (thermal/wind/DSM/imports) could provide up to about 8,000 GWh of energy if required.

It is important to note that the non-hydraulic resources involve substantial costs due to:

- SCCT thermal generation costs being uneconomic (MH loses money operating its inefficient SCCT plants);
- Wind and DSM "tied" to MISO market prices and not readily dispatchable; and
- Imports being non-firm and, possibly, involving high market prices.

Consequently, from a financial perspective MH appears to count on each year being an average or above-average water flow year, as this would avoid the Utility having to rely on either its SCCT thermal generation or market priced imports. When MH employs imports to fulfill firm or opportunity sales, at best MH's profit margin is much smaller than when the Utility's own hydraulic generation resources are used. At worst, it is a money-losing proposition.

18.1.4 Potential Drought Costs

The actual net revenue loss associated with extended drought events is dependent on the value of:

- Foregone export sales (primarily high-value peak opportunity sales); and
- Additional fuel and power purchases.

18.1.5 Overselling

Total dependable energy, as defined by MH, consists of about 75% hydraulic generation resources (the major factor in MH's embedded cost structure) and 25% non-hydraulic generation resources.

Circa 2003/04, MH anticipated that a domestic load of 19,000 GWh and dependable export sales of about 6,000 GWh could be served from average hydraulic generation output. Unfortunately, and with a low level of energy-in-storage in April 2003, hydraulic output was only 18,500 GWh in MH's 2003/04 fiscal year. MH was faced with a 9,000 GWh shortfall that had to be met at largely very unfavourable prices. The very low April 2003 energy-in-storage level was largely the result of a high level of off-peak opportunity sales undertaken by MH in its fiscal 2002/03 year. These opportunity export sales made in the year prior to the drought, and at low sale prices, had substantial negative consequences once the drought set in.

Circa 2006/07, MH was expecting a domestic load of about 23,500 GWh and dependable export sales of 3,500 GWh, again to be served by hydraulic generation. MH's opportunity sales made early in the fiscal year, again at relatively low prices, subsequently necessitated 1,800 GWh of energy purchases at prices much higher than the Utility obtained through the earlier opportunity exports.

Overselling leads to the depletion of energy-in-storage, which can magnify a subsequent energy shortfall and drive up the negative financial impact of a drought situation.

18.1.6 Board Findings

When MH looked to calculate what it would consider to be appropriate reserves or retained earnings levels to protect against the financial consequences of drought, a five-year-drought (based on 1987/88 to 1991/92) was selected as representing what was, in essence, a financial stress test.

The Board has heard from various consultants that a five-year drought is “stressful enough” for MH, but the Board has not been convinced that the drought events extending from 1929/30 to 1942/43 (including both a five-year and a seven-year drought) would not serve as a more appropriate stress test.

With respect to MH’s drought impact evaluation, and in particular the five-year and seven-year droughts, the Board finds that MH’s quantitative analysis reasonably defines the energy shortages that would impact MH’s energy supply. However, should MH be faced with shortage pricing such as was experienced in 2003/04, this would impact import pricing to meet any shortfalls.

The Board accepts the need for a defined drought risk reserve in establishing a retained earnings target as proposed by MH. The Board expects MH’s next IFF to address the risk of, if not the reality of, a lower potential export revenue situation.

18.2.0 EXPORT MARKET RISK

18.2.1 Supply Variability

In mean (or average) flow years, and assuming no major equipment failure, MH’s hydraulic generation should be adequate to meet domestic load and about 3,000-4,000 GWh/year of export sales. These export sales would typically consist of 2,000-3,000

GWh/year of firm price contract sales and a further 1,000 GWh/year of peak opportunity sales. Prior to 2005/06, these peak opportunity sales prices tended to equal or exceed the firm fixed prices. Currently, the peak opportunity sales achieve about 50% of firm prices.

In above-average flow years, MH looks to import electricity from time to time to expand peak opportunity sales to the limit of peak transmission tie line capacity and sell electricity at peak prices when available. Nonetheless, currently, under on-going high flow conditions, MH's average opportunity sales are achieving less than 3.0¢/kWh (peak and off-peak average).

In below-average flow years, MH's hydraulic generation can barely meet domestic demand. As a result, in such circumstances MH's exports mostly come from purchased energy. Consequently, net export revenues tend to be low, and can even be negative if the price of export commitments is lower than the purchase price.

Transmission constraints on exports in above-average flow years mean that MH can only export a maximum of 7,000-8,000 GWh/year during peak periods. Additional energy surpluses must be sold during the off-peak period (at prices as low as 0.5¢/kWh). The total tie line capacity limit for sales into the U.S. MISO region is 15,000 GWh/yr, including peak and off-peak sales.

18.2.2 Decreasing Export Market Demand

In the absence of low-flow and drought situations, MH can still be faced with low export revenues as a result of weak export demand. Recent MH IFF's assume that all surplus energy can be sold into the U.S. MISO market at favourable prices. This is not necessarily the case.

At the beginning of the 21st century, MH was able to readily sell 9,000 to 10,000 GWh of energy into the MISO market. These sales took place in the context of an environment that involved natural gas prices rising well above $5.30/GJ, no new coal thermal plants coming into the market due to threats of CO_2 pricing, and a “booming” U.S. economy. At that time, MH could reasonably anticipate an ever increasing demand for its surplus energy.

Circa 2004/05, the prospects for selling all of the energy output from Keeyask G.S. and Conawapa G.S. (estimated to total 12,000 GWh in average flow years) seemed certain. However, with many MISO states moving to renewable energy mandates, and with wind energy currently being eligible for a 1.7¢/kWh federal subsidy in the U.S., MH is now faced with substantial additional competition for market volume.

Prior to 2003/04, approximately 25% of MH’s contracted export sales were inter-provincial Canadian sales. Since that time, MH appears to have focused almost entirely on MISO. That focus on MISO was initially successful, partly because the U.S dollar was about 1.2 times the Canadian dollar. More recently, with the economic downturn, the advent of shale gas, a Canadian dollar more or less at par and a no longer “booming” American economy, the U.S. market for MH’s energy has become much less favourable.

18.2.3 Export Market Price Trends

MH’s export sales into the MISO Market were initially quite profitable. This was in large part due to a very favourable foreign exchange rate (the Canadian dollar fell at one point to well below $0.65 USD) and seemingly ever-increasing natural gas prices. From the currency exchange alone, MH derived an average of $85M/year of additional revenues at the time.

This favourable situation no longer exists. However, MH’s IFF09-1 still assumed a U.S. dollar equal to $1.10 CAD and to increase to $1.20 CAD. Consequently, on this factor alone, MH faces a substantial downside risk on export prices. The currency factor may, however, be partially offset by the resulting “depreciation” of that portion of MH’s debt that is owed in U.S. dollars.

MH faces a combination of negative export circumstances in the current market environment. These circumstances include lower demand, subsidized wind in the U.S., reduced attention to carbon emissions, and the advent of shale gas. On the spot market, natural gas is presently selling for $3/GJ, which is only 20% of the peak price encountered in the last decade. In recent years, MH has made, and still is making on-peak and off-peak sales at an average price of less than 3¢/kWh. This represents ongoing pricing risk as a result of eroding export profitability.

The relative pricing of peak period opportunity sales and contract sales has changed since 2008/09. Day-ahead and spot prices used to be higher than fixed long-term contract prices. That is no longer the case. To the contrary, spot pricing is now up to 40% lower than contract pricing. This, too, represents an ongoing pricing risk.

18.2.4 Future Export Revenue Prospects

There continues to be significant excess energy supply in the MISO market, and expanding wind resources and new CCCT natural gas thermal generation constructed within the MISO area may maintain the excess resource situation for a considerable period ahead.

MH's new generation (from Wuskwatim and from the planned Keeyask and Conawapa generating stations) will carry fully-costed initial in-service costs in excess of 10¢/kWh. That indicated cost is almost double the current net cost of not only wind resources but also the cost of shale gas-driven CCCT generation.

With a U.S.-Canada exchange rate near parity, MH may be faced with an extended period of lower export revenues than is forecast in either MH's IFF09-1 or IFF10-2, and an extended period before a return, if it ever occurs, to the US dollar being worth $1.20 CAD (as assumed in IFF09-1).

18.2.5 Board Findings

In the Board's view, MH may be facing close to its worst-case export market scenario, particularly relative to the situation anticipated in IFF09-1, because of such factors as:

- projected major generation and transmission project costs 50% higher than initially forecast;
- natural gas generation costs having decreased by 30%-40% or more;
- the U.S./Canada exchange rate decreasing revenues by 20% (offset in part by depreciated value of MH's debt held in U.S. dollars);
- a complete lack of carbon pricing as opposed to the $20-30/tonne of CO_2 apparently once forecast by MH; and
- continued U.S. wind subsidies along with decreasing wind generation costs due to technical improvements and efficiencies.

Furthermore, the Board does not see how all of these negative market scenarios will be reversed for many years to come. The obvious risk faced by MH is that the current status quo prevails for the foreseeable future.

18.3.0 INFRASTRUCTURE FAILURES

18.3.1 Context

MH has experienced, on a periodic basis, the loss of generation and transmission system components due to both natural forces and the deterioration of parts or components. In large part, MH has been able to respond to such losses in an expeditious manner and has avoided substantial power outages to date.

The loss of various distribution system components due to natural forces, accidents and deterioration has been more frequent than the loss of generation and transmission system components. However, the extent of these failures is typically localized and blackouts have been limited to days (if not hours) rather than weeks or months.

MH's infrastructure failure risk is primarily focused on the major generation and transmission systems and the potential for broad-scale power outages. MH has frequently suggested that a failure of major generation and transmission components represents a greater financial risk than that occasioned by an extended drought period. MH looks to system redundancies to mitigate and/or preclude any inability to meet domestic load and firm export obligations.

18.3.2 Historical Events

The failure of both Bipole I and II occurred in October 1996, but the main north-south Manitoba AC lines were not affected. Subsequently, MH has progressively moved towards the implementation of a Bipole III concept, able to meet domestic loads without Bipole I and II.

A partial failure of MH's HVDC or HVAC transmission system would be more serious than a partial loss of generation capacity.

18.3.3 Dam Safety

The Board understands that like other hydro utilities, MH periodically reviews the potential for various failure modes of its hydroelectric generating stations. To date MH has not produced the Asset Condition Assessment Review requested by the Board in the 2008 GRA.

18.3.4 Consequences of Failure

A catastrophic total failure of MH's generation and/or transmission infrastructure appears to be a remote possibility. More likely is a partial failure, where the greatest cost implications will arise not from the requirement to repair or replace the failed infrastructure, but from lost revenue from exports sales or, perhaps, domestic sales that cannot be fulfilled from MH's own generation.

18.3.5 Board Findings

MH has experienced a wide array of infrastructure failures within the various components of its generation, transmission and distribution systems. Undoubtedly, similar events may be expected in the future.

With respect to the Bipole I and II tower failures, it would have been prudent for MH to conduct a comprehensive post-mortem analysis of the failures, and, as well, a cost/benefit analysis to justify the Bipole III project. The Board is of the view that to date, alternative scenarios to Bipole III have neither been adequately explored nor documented.

18.4.0 OPERATIONAL RISKS

18.4.1 MH's Forecasting Process

With upwards of 95% of MH's annual energy supply now coming from hydraulic resources, an ability to anticipate river flows and forecast hydraulic generation is essential. MH apparently relies primarily on antecedent stream flows conditions to estimate current-year and upcoming flows and hydraulic output.

A key element of MH's water supply management involves the ongoing prediction of flows and hydraulic generation for 6, 12 and 18 months in advance. This is to ensure adequate energy supply for domestic load and firm committed exports for both the current year and the upcoming year.

The Board understands that MH does not attempt to predict annual water flows via specific hydrologic parameters (such as winter precipitation, snow pack, snow melt, spring run-off and precipitation) but rather employs antecedent regression relationships to forecast annual system inflows based on actual flows. In calculating generation forecasts for the year, MH appears to assume average levels of energy-in-storage as both the starting point and end-point. This approach may not raise concerns in average or above-average flow years, when excesses or shortfalls can be managed at low cost.

However, in below-average flow years the negative cost consequences of over-prediction could be substantial.

The practical limit of MH's existing hydraulic generation capacity is about 37,000 GWh/year under high flow conditions as experienced in 2005/06 (the 2007/08 Q4 output was 9,700 GWh over a three-month period).

18.4.2 Concerns about MH's Forecasting Process

MH's reliance on actual April system inflows to define potential hydraulic generation for the upcoming year does have some merit, but only if used in conjunction with a consideration of actual April 1st energy-in-storage and a quantitative assessment of precipitation during the preceding winter months (October to March). A high April system inflow may, in some years, be the result of an early spring melt rather than an indication of high flow volumes to follow. Conversely a low April system inflow, in some years, could reflect a late spring melt. A correlation of energy-in-storage and winter precipitation with MH's existing factors should provide an additional and better indication of potential hydraulic generation surpluses.

MH's response to favourable April flows can have significant implications. Maximizing export sales in April and May can be a high-risk venture if subsequent summer flows end up being low. This applies to all opportunity sales and to bilateral summer contract sales for June-September period.

MH apparently does not carry out an annual back-testing of its hydraulic generation forecasting process and assumptions. Such a test would be extremely useful as a means of confirming the reliability of MH's current procedures and assumptions.

18.4.3 Drought Events of 2002/03 and 2003/04

Leading up to the 2003/04 drought year, MH exported about 9,900 GWh in 2002/03. 4,800 GWh of that amount was exported in the first six months of the year and 3,900 GWh in the second six months. According to the Board's calculation, these export transactions involved 7,900 GWh purely from hydraulic resources and 2,000 GWh from imports. As a result, energy-in-storage decreased from 6,300 GWh in April 2002 to 4,200 GWh in April 2003.

As a result of this decrease of energy-in-storage, in 2003/04 MH was only able to achieve 4,400 GWh of physical exports while requiring 7,000 GWh of imports. Another 2,500 GWh of firm contract exports were bought back and never delivered. About 2,600 GWh of energy imports were required to meet the domestic load shortfall.

If a similar drought were to occur in the 2011 to 2015 period, the results would likely be quite different. While the total energy obligations (both for domestic load and for firm exports) and energy shortfalls would be quite similar, the resulting costs would reflect higher energy prices and the resultant deficit would be substantially larger.

18.4.4 Board Findings

MH's Prediction Process

MH's IFF process apparently provides hydraulic generation estimates for:

- Year 1 - based on 6 month actual generation + 6 months median projected generation;
- Year 2 - based on actual April energy-in-storage adjustment + 12 month median projected generation; and
- Year 3 - based on average energy-in-storage + 12 month mean projected generation.

The Board understands that MH does not use the IFFs to make its actual operational decisions.

It appears to the Board that MH looks to April hydraulic generation (river flows) to confirm, on an antecedent basis, the hydraulic generation resource and hence energy available for export for the next 12 months. A September review based on September hydraulic generation is also used to verify the available MH energy and the need (if any) for winter imports.

Regulatory Reviews

MH's American utility customers are faced with rigorous reviews by the State Public Utility Commissions with respect to their proposed import contracts with MH (i.e., MH's export contracts). MH's export contracts, and the volumes and prices involved, are significant in determining domestic consumer rates; and, as such, need to be reviewed by the PUB even if they are filed in confidence as opposed to being placed on the public record.

2003/04 Drought

While MH contends that its management of the events leading up to and including the 2003/04 drought were totally appropriate, there has not been a detailed back-testing (post-mortem) of MH's water supply management and flow prediction system to date. The Board sees a need for MH to enhance its modeling forecast by adding a comprehensive hydrologic component.

It is apparent that MH's model employs antecedent forecasting and does not look to a hydrologic prediction in preparing annual hydraulic generation estimates. Evidence from external experts and the independent consultant indicates that the models are less accurate in replicating actual low-flow periods (such as 2003/04) than they are in replicating average or above-average flow scenarios. The Board sees this as a significant risk issue.

When MH suggests that it does not look to anticipate or predict pending drought situations, the Board can only ask why MH would not attempt to reduce energy consumption as soon as accumulated precipitation data in any year indicates that watershed runoff could be significantly below average. Reducing energy sales a month or two earlier could significantly alter the level of losses during a drought period.

The need for new hydraulic generation within MH's system is apparently determined by domestic load growth and export contract commitments. In the Board's view, MH should revisit the rationale for determining dependable energy resources and the acceptable level of non-hydraulic resources that should be used to establish firm export contract commitments.

In 2003/04, the energy shortfall resulting from a drought scenario was entirely covered by imports at unfavourable market prices. This suggests to the Board that MH does not have adequate firm resources to meet MH's firm supply obligation under droughts as historically experienced.

A renewed focus on serving domestic load first in MH's "Business Plan" could, while potentially limiting MH's export operations, ultimately benefit Manitoba consumers. The Board sees some merit in further researching and testing such an alternative focus.

18.5.0 JOINT FREQUENCY RISK CONSIDERATIONS

18.5.1 Retained Earnings Reserves

Currently MH's retained earnings reserves are expected to buffer the financial consequences of a five-year drought and shield consumers from other potentially coincident events such as:

- lower export revenues or, alternatively, shortage import prices;
- potential infrastructure failures;
- lack of domestic load or industrial growth;
- power resource planning that relies on substantial non-hydraulic resources;
- capital cost escalation;
- operational risks such as drought anticipation/overselling in spring; and

- regulatory risks.

Nonetheless, the reserves are not necessarily adequate. The quantification of the reserve will remain an issue for future GRA hearings.

18.5.2 Dedicated Reserves

MH is essentially opposed to segregating specific drought reserve requirements for particular risks. However, it could be argued that MH's overall global retained earnings reserve is subject to the independent risk of depletion due to non-drought factors such as:

- market price collapse;
- "sticker shock" capital cost escalations; and
- lack of domestic load growth.

The suggestion by the independent consultants (KM) that MH create an EIS reserve is not without merit and is worthy of further investigation. Constraints on the withdrawal of EIS could be seasonally defined, so as to reduce the likelihood or magnitude of a supply shortfall. This would not preclude MH's management of energy resources, but would ensure a minimum hydraulic resource level at all times.

18.5.3 Intervener Positions

The interveners concluded that MH's current approach of having one global retained earnings reserve was adequate.

18.5.4 Board Findings

In the Board's view, the entire issue of multiple interdependent risks has not been satisfactorily reviewed or resolved. There is a reasonable concern that the Utility's forecast retained earnings will not be realized or, if realized, maintained.

With the potential for multiple claims on a global retained earnings reserve, there exists risk that the reserve could be substantially depleted in advance of any future drought, meaning that a drought could impair MH's capital position by far more than now expected. This, in turn, could lead to higher consumer rates.

18.6.0 RISK EXPERTS

18.6.1 KPMG

The Board directed, in Order 32/09, that an independent comprehensive risk study be undertaken and filed, with the specific terms of reference for the study to be approved by the Board.

In late 2009, the Board was asked for input by MH towards establishing terms of reference for what the Board expected to be an independent comprehensive risk study, one which would address all of the risks identified by the Board in Order 32/09. The Board provided this input, and KPMG was retained by MH to carry out the study in November 2009. However, the final terms of reference were not as sought by the PUB and previously agreed to by MH.

MH advised that its Audit Committee authorized the changes to the terms of reference for the KPMG risk review and specifically approved removal of the requirements requested by the PUB for an independent and comprehensive risk study. As such, while the KPMG reports (and the cost of KPMG's representatives, who were assisted by the firm's external legal counsel at the hearing) cost MH approximately $4.0M, the work performed was not broad enough to address the Board's concerns. The terms of reference MH provided to KPMG focused on a review of the allegations of the New York Consultant (NYC) previously employed by MH rather than the identification and costing of MH's risks.

KPMG, as directed by MH, concentrated on the NYC's allegations and the development of an analysis with respect to those allegations. KPMG acknowledged in response to pre-hearing information requests and upon cross-examination during the oral hearing that it never intended to respond to any of the specific assertions of the NYC regarding MH's operations, risk management or risk governance. KPMG considered the NYC assertions, identified major issues arising from those allegations, and then analyzed those issues using the review process set out below. KPMG confirmed (on cross-examination) that the NYC had not missed identifying any of the major risk issues faced by MH.

KPMG reviewed existing risk review studies, obtained explanations of operational and planning methodologies from MH, and limited its analysis to a consideration of whether MH was operating reasonably in respect of the issues under review as defined by KPMG. KPMG did little independent verification of MH's underlying data as part of its work. For example, KPMG's Net Present Value (NPV) analysis of MH's preferred future development scenario compared to one alternative development scenario was based on MH's data, and KPMG did nothing to verify the underlying data assumptions that supported the particular stress test runs to generate the NPV outputs. Also, KPMG confirmed that with respect to its review of MH's price forecasts, it made no attempt to examine the validity of the forecasts. Rather, KPMG focused on examining the method used by MH of purchasing a number of forecasts and creating an average of the forecast values.

KPMG recognized that the original terms of reference as approved by the Board included the need for consultation with the Board and its advisors as necessary. KPMG determined that this consultation was not necessary to complete its work, even though the work was envisioned to fulfill a Board directive arising from Order 32/09.

Based on difficulties KPMG encountered with the NYC, it chose not to attempt to make contact with the NYC to obtain an explanation from the NYC as to any assertions which appeared inconsistent, unclear or ambiguous. In the circumstances that existed, which included legal action undertaken by MH against the NYC, it appears unlikely in any case that KPMG would have received any cooperation if had made such an attempt.

Following a court application by MH against the NYC on the issue of publication and use of the KPMG report, it became clear to the Board in its pre-hearing process that the KPMG report would not be tabled with the Board unless the Board served a subpoena on MH.

Accordingly, a subpoena was served on MH for production of the KPMG report on April 15 2010, the date the report was issued. MH complied with the subpoena and the KPMG report was tabled with some redactions, in compliance with the subpoena. In the course of a redactions motion before the Board, the Board approved several redactions in the KPMG report. These are set out in PUB Order 95/10. A final redacted KPMG report was then put on the record of this proceeding.

KPMG also performed an adjunct risk governance / risk management process review for MH between March and May 2010 and issued a separate report on May 2010. The KPMG risk governance / risk management process review report was tabled at the commencement of KPMG's testimony in this hearing on February 28, 2011.

The Board finds that KPMG's report is not an independent assessment of MH's material risks as was originally envisioned by the PUB. Given the somewhat narrow approach adopted by KPMG and the limited nature of KPMG's analysis, this work has limited value despite its steep price tag.

In oral testimony, KPMG's panel addressed the major topics its considered as part of its review process. KPMG's key findings were as follows (the first two conclusions were not contained in KPMG's draft report but were added to the final report after a review by MH's Audit Committee):

- There is no material risk of bankruptcy for MH as a direct consequence of MH's export power sales practices.

- There is no evidence to support an assertion of losses approaching one billion dollars in the five years preceding KPMG's review based on analysis of MH's modelling, export sales contracts and risk management practices.

- MH's strategy of entering into long term contracts and securing transmission rights in development of its system is a prudent strategy.

- MH has operated in accordance with its legislative mandate.

In two places in KPMG's draft report, KPMG made the statement that

> *"MH's core business objective is to provide its domestic customers low-cost and reliable energy service."*

On cross-examination as to why MH's Audit Committee requested that statement removed from the final version of the KPMG report (from which it was in fact removed), MH's Chief Financial Officer responded that MH never described its core business objective in this manner and that it was a truncated interpretation of MH's core business made by KPMG that MH did not agree with.

As part of its review, KPMG concluded that a legislative mandate for MH, and thus a key MH goal, was to provide low-cost power to MH's domestic customers. Given the process used by KPMG to complete its assignment, KPMG would have been informed in its interviews with MH's executive staff that this was indeed an objective of the utility. Furthermore, MH's Corporate Strategic Plan 2009-10 filed with its GRA application states that a defined target is to provide the lowest retail electricity rates in North America.

MH's testimony and submissions clearly support a long term plan which supports stable, low annual rate increases (said to be projected to remain close to inflation) for domestic customers over the 20-year time horizon shown in MH's IFFs. Indeed, MH's intention to add new generation in advance of the need of its domestic customers, as part of its decade of investment and in accordance with its preferred development scenario, is premised on export sales creating net revenues that over time will result in reduced domestic rates.

With respect to MH's risk governance structure, while KPMG generally concluded that MH's corporate risk management function is consistent with leading and prevailing practices, KPMG identified a number of risk policy areas where MH rated sub-par and made recommendations for improvement. MH subsequently reported to the PUB in the hearing process as to progress on these recommendations. Among other things, MH reported on an increased role for its Middle Office as well as increased staffing and expertise for its Middle Office. Improvements undertaken by MH include establishing a role for the Middle Office in the review of long-term export contracts. KPMG also recommended improved risk analytics technology, which appears to implemented on an ongoing basis as part of MH's improvement to its risk management infrastructure.

KPMG concluded that MH's financial risk management function is consistent with leading practises.

KPMG concluded that MH's actions, as understood by KPMG, demonstrate prudent power risk management practices as related to major export contracts and term sheets, including a conservative stress testing methodology, transaction processing controls to mitigate against human error and operational risk, compliance and risk monitoring by the Middle Office, and a comprehensive suite of reports.

KPMG also indicated that it reviewed MH's "HERMES" and "SPLASH" modelling programs. HERMES is used to plan operations of a system in the near term. SPLASH is used for long-term planning processes and to establish a business case for new generating plant additions. SPLASH also provides input for medium- to long-term financial forecasting. KPMG further concluded that MH has taken appropriate care and due diligence in developing, operating and maintaining the models. On the key issue of forecasting water flows, KPMG endorsed antecedent forecasting methods in use by MH as a useful and reliable approach to this type of forecasting.

KPMG also noted that with respect to the SPLASH model, the use of perfect foresight allows for certain conservative projections which are reasonable for the purposes for which the model is used by MH. In considering the trade-offs with respect to the perfect foresight methodology, KPMG also concluded that financial losses associated with droughts are in fact inevitable.

KPMG noted that the use by MH of the 1937-1942 drought periods is appropriate for MH's planning to determine dependable energy. KPMG acknowledged that the appropriate approach for determining dependable energy depends on the Corporation's risk tolerance. A more stringent definition of dependable energy would result in less risk of financial loss in the event of a drought, but such a strategy also has the prospect of lowering MH's revenues, on average, to the extent that it must spill water or sell on the opportunity market for less certain return.

KPMG looked at pricing in the long-term export contracts and Term Sheets as well as the structure of the long term contracts and risk capital reserves. KPMG analyzed the pricing process and concluded that MH has an appropriate methodology for arriving at the sales prices in its long-term contracts. KPMG did recommend that MH clarify the role of the premium applied to its long-term contracts, confirm the appropriate magnitude, and also that it should do a better job of documenting its pricing analysis and its future avoided cost analysis. More explicit use of the avoided cost analysis in future pricing methodology is also recommended. KPMG further recommended that in the process of reviewing export contracts and terms sheets, MH's Middle Office should have a defined role to perform a challenge function.

KPMG supported MH's long term contract strategy and found that it has the potential to mitigate market risk for MH through diversification. KPMG concluded that MH's drought risk will be mitigated because of returns (revenue) to be generated under the export contracts and the extra transmission capacity to support required imports in drought situations.

KPMG also performed a net present value (NPV) analysis to compare the Sales Scenario (being MH's preferred development sequence) to a No Sales Scenario which included an alternate expansion plan with no long-term contracts. MH redacted all of the supporting data in the KPMG report, so that there was no opportunity for the Board or Interveners to examine the NPV analysis in the report.

To perform the NPV analysis, while KPMG provided data run requests to MH, it confirmed that it performed no independent analysis of the inputs for the NPV calculation, but instead relied on MH for that information.

Based on the assumption inputs in the analysis, KPMG concluded that under all scenarios, including drought stress test cases, the NPV of MH's Sales Scenario/preferred option was greater than the No-Sales NPV. KPMG acknowledged that with the escalating costs of capital projects, a downward adjustment in the NPV of the preferred scenario would be required. Likewise, with export prices declining as projected by Mr. Rose of ICF, there would be further downward pressure on the NPV of the Sales Scenario.

KPMG also assessed net income and retained earnings over the long term with respect to the Sales and No Sales Scenarios for MH. The picture was less clear with respect to differences in net income between Sales and No Sales in the shorter term, but KPMG concluded that in the long term, net income and retained earnings were better under the Sales Scenario.

KPMG acknowledged that its NPV analysis was limited to input values for various components as available at the time of the report. Significant increases to the estimate of the capital costs of the proposed capital projects at the heart of the scenarios, being Keeyask, Conawapa and Bi-Pole III, were not available to KPMG and would materially change the analysis. KPMG confirmed that all other things being equal, higher capital costs would lead to a lower NPV in their analysis.

Given the limitations of KPMG's final terms of reference and its approach to the preparation of the report, it is useful to consider several of the risk management and risk governance issues brought forward by KPMG (and other experts before the Board) in response to the NYC's assertions. The filing of KPMG's adjunct risk governance / risk management report, the testimony of the KPMG panel, and cross-examination of the KPMG panel all added value to the engagement. KPMG's evidence suggested the following:

- The NYC identified all significant risk issues facing MH, although no specific NYC reference to quantification of MH's operational losses could be verified by KPMG. By and large, KPMG did not attempt to respond to the specific assertions of the NYC.

- The system models developed by MH for production and for long-term planning are similar to models used by other utilities, and the models are doing what they are required to do. The models are being upgraded and calibrated on a continuous basis.

- MH should proceed with its planned enhancements of the models. MH should better quantify and communicate to stakeholders, including the PUB, the impacts of the perfect foresight assumption in the calculation of drought costs. Further, MH should explicitly consider uncertainty in future water flows in the modeling process used to identify optimal production decisions. MH should consider assessing the financial impacts of drought events worse than those found on the historical record.

- MH should conduct more scenario analyses, and should do more stress testing and back-testing to evaluate risk exposure and model accuracy. MH should also formally document its in-house models, which will mitigate the risk for the time when the experienced, highly knowledgeable staff that has the knowledge about the models leaves MH. Independent peer review of the models is also recommended.

- MH needs to continue to develop its risk management capabilities, and specifically the role of the Middle Office in risk management.

- MH must take a careful approach to future development to take advantage of the opportunities available based on Manitoba's hydrologic resources. MH must ensure that costs of the development plan "don't go way out of whack", make sure good prices are achieved in the final long-term export contracts, and make sure that the benefits flow back to Manitoba ratepayers and are not shared too widely with other parties.

- MH should create a defined risk management philosophy and create risk management objectives and a mission statement respecting risk policy. It should define its risk appetite by articulating a statement that reflects strategic growth goals and desired returns from a strategy. MH should differentiate risk appetite from risk tolerances, the latter being acceptable variations relative to the achievement of objectives. Better documentation of the risk management function through management and governance in MH are also recommended. Specific recommendations regarding monitoring and reporting of various risk issues are detailed in KPMG's May 2010 report.

- MH would benefit from completion of a final documented drought preparedness plan. Although KPMG found that MH is prudently managing its approach to drought as one of MH's biggest risks, a written plan would be an improvement as the plan would then be documented in one place, and available for the purpose of communicating it to all stakeholders and interested parties.

- MH's capital structure should continue to be formally reviewed on a regular basis. Of particular significance at this time are the major capital expansion to MH's generation and transmission system and MH's risk management improvements, which may affect MH's optimal capital structure. Better information would assist decision makers on the optimal capital structure for MH through future periods of significant change and ongoing uncertainty. The appropriate capital structure will continue to be an ongoing issue for the company, the PUB, the Province, ratepayers and lenders.

18.6.2 Dr. Kubursi and Dr. Magee

After consultations with MH and the Interveners in the pre-hearing process, and having been aware of the limited terms of reference provided to KPMG by MH, the Board determined that it would retain independent experts to perform a study of MH's material risks, in accordance with the scope of the GRA and the Terms of Reference which were attached as a Schedule to Board Order 30/10. As a result, Drs. Kubursi and Magee (KM) were retained and accepted the assignment to fulfil the assignment under the terms of reference. They retained their own counsel and proceeded with their investigation and analysis. KM also met with a number of the Interveners and, as required, provided general guidance to the Interveners and answered inquiries on risk principles.

KM worked with MH pursuant to a confidentiality agreement and spent significant time gaining knowledge of MH's operations, its models, and its risk governance and risk management processes. This knowledge was used by KM to prepare its own statistical analyses of revenue results for MH's electricity operations under various scenarios, using the same computer software which is the basis of MH's PRISM model. KM's statistical distributions were produced to assist the Board and hearing participants with a better understanding of risks faced by MH and the related implications for the financial health of the utility, its ratepayers, and the Province of Manitoba.

As a result of the limitations imposed by the confidentiality agreement, KM chose to use publicly available data, from Statistics Canada, to conduct its data analyses. Ultimately, both MH and a number of the Interveners challenged the validity of the data runs and distribution curve outputs generated by KM based on the Statistics Canada data, as well as subsequent refinements presented by KM to their initial calculations.

KM submitted that it could assist the PUB and inform the ongoing discussion of the risks faced by MH and decisions arising therefrom, in particular in the following areas:

- evaluating MH's risk governance systems and risk management strategies;
- quantification of risk;
- review of MH's operational and planning models, pricing options, investment decisions, and MH's overall business performance; and
- suggesting statistical methods for dealing with uncertainty, for example, in future water flow predictions.

While the Board is not certain that it can rely on the accuracy of the particular distribution curve graphs included in the KM report or KM's quantification of MH's drought costs, it is satisfied that the broader insights drawn by the independent experts from their data analyses are instructive as to the matters identified in the terms of reference and the MH risk review as part of the GRA.

The independent experts were qualified as experts to provide opinions in the areas of econometrics and statistics, including time series analysis, economics, production systems, risk analysis and optimization models.

In preparation for their work, KM also reviewed numerous reports and studies respecting other public utility systems and the risk assessment and risk management processes at different utilities. Dr. Kubursi in particular studied water and drought prediction models, operation research in power generation, operation and planning systems, as well as optimization systems and software.

Dr. Kubursi and his counsel Mr. Wood also met with the NYC in New York in June 2010 in an effort to understand the NYC's concerns and supporting analysis respecting those concerns. During the meeting, the NYC was prepared to identify high level issues and repeated its general assertions regarding problems in MH's risk governance and risk management areas, as well as alleged operational deficiencies and mismanagement. However, the NYC was not prepared to engage in a more detailed discussion or review of its supporting information which backs up its assertions. The NYC was not willing to share the explanation for the quantification of specific losses alleged to have occurred.

Although Dr. Kubursi concluded that the NYC displayed a strong scientific intellect and had a sound educational background along with experience in risk analysis, the NYC was reticent to share information to assist KM in their completion of their assigned tasks under the terms of reference. Further attempts to reconnect with the NYC thereafter proved fruitless.

KM generated its primary report in November 2010, which report was supplied in a redacted form based on redactions requested by MH. The redactions primarily relate to MH's long-term contract pricing and other contractual provisions, as well as certain water flow data.

KM generated a further Reply submission, which became the document used as the basis of their direct oral evidence in the hearing. KM testified before the PUB and were subject to cross examination by Board Counsel, the Interveners and MH.

The Board has identified the following findings and conclusions of KM, based upon their reports and testimony:

- There may be benefits derived by MH in integrating its operating and planning models.

- MH is a Crown Corporation, seeking to pursue maximum revenues and strong net income while serving the best interests of the Province of Manitoba and domestic ratepayers. This is identified as a duality of interests within MH. The regulatory regime in Manitoba vests authority in the PUB, which is tasked with moderating the monopoly power which MH enjoys to ensure balance. Prices should be equal to marginal cost and only reasonable rates should be charged to Manitoba customers.

- MH is likely prone to the "principal/agent" dilemma, the principle being that there is a difference in risk tolerance between the utility and its customers. Citizens are risk-averse based on well-known and studied general principles of economic behaviour. MH as a corporate entity may be less risk-averse.

- There are naturally existing information asymmetries between MH and its stakeholders.

- Moral hazard may be an issue for MH. The Utility may be tempted to undervalue risk and to pass the cost of its risk-taking onto domestic customers.

- Risk management best practices require a continuous and systematic process. Beyond identifying and prioritizing risks, procedures must be established to estimate probability density functions and ranges in systematic, transparent, and replicable ways.

- Statistical procedures should be verified and validated by subject matter experts in the Front and Middle Offices of MH.

- Once strategies for assessing risk are in place, procedures to deal with them must be established to reduce risks to the enterprise.

- Individual responsibility and accountability for defined risk matters is required. KM confirmed on cross-examination that MH appears to have an individual responsibility/accountability system in place.

- There must be a vested defined internal authority to implement risk management processes, along with properly allocated resources, necessary expertise and appropriate oversight in the process.

- There must be a process for monitoring and tracking outcomes and learning from mistakes as part of the risk management regime at MH. The process is optimized as a continuous exercise.

- MH has shown good effort in implementing a risk governance and risk management system that is still evolving.

- As a result of the 2003/04 drought, MH recognized that it needed a comprehensive risk management plan.

- Gaps in the MH risk management system include the need for one group to undertake valuation of risk and another group, in the Middle Office, to validate the assessment.

- Qualitative analysis of MH risk can be improved. Middle office validation of quantification is necessary. Quantification should use market values, such as mark to market measures, which are preferred over other benchmark evaluations of financial risks.

- Greater expertise of statisticians and actuarial experts would assist the Middle Office and added risk analysis expertise is required.

- Risk management must take place at the highest level in the organization for MH and must continue to report to the CFO. The Middle Office must be given importance in the MH hierarchy which is necessary to allow it to function effectively with this recommended structural change.

- Risk preparedness plans are needed for all costly risks, including a written drought preparedness plan.

- One of the benefits of a drought preparedness plan is to avoid a well-established phenomenon of reaction lag time to deal with future droughts. This includes lags in recognition, diagnosis, response, action and outcome. A good plan would take into account all components and identify a set of criteria, responses and responsibilities to eliminate the lag.

- All business transactions must include a risk assessment that would be first prepared by the business unit and then reviewed by the Middle Office. Specifically, long-term contracts must fall into this review process.

- MH should introduce statistic uncertainty to its models, which are operating on deterministic structures. The current structures do not optimize assessment of risk.

- Outside peer review for the validation and audit of MH's models is important. MH should proceed to implement processes for validation and audit.

- MH's electric load forecast is reasonable, and to improve it MH should move to integrate probabilistic variables. The group responsible for the load forecast should be integrated formally into the MH model staff community. This supports greater integration of the models and is of benefit to all of the modelling staff at MH.

- MH should reconsider its use of variables for multiple forecasts in its economic outlook preparation. The practice of drawing individual variables from various forecasts may lead to incorrect outcomes.

- With respect to prediction of water flows, MH's should consider methods beyond the currently used historical simulation methods to predict droughts of greater severity than those in the historical record.

- Upon review of the NYC public document respecting high level assertions, and upon review of various related reports prepared by MH, KPMG and ICF, KM is unable to confirm any specific assertions of losses alleged by the NYC or any specific allegations of mismanagement. KM saw no evidence to support such allegations during its study.

- With respect to general issues of risk identified by NYC, areas for improvement were identified in detail in the KM report and elaborated on by KM in testimony. Included in recommendations are subject areas of model governance, model utility and relevance, model output and predicted accuracy, water flow analysis, drought risk, and risk governance and management in the MH middle office.

- Numerous benefits may accrue to MH as a result of entering into new long term contracts with its counterparties.

- High import prices are a threat in drought periods, but the long-term contracts are structured to define price limits and offer greater curtailment protection to MH under certain drought conditions.

- NYC's drought calculations are of a magnitude that is glaringly low. However, there is a need for adequate risk capital to mitigate against MH's long term contract risk exposures, which are a serious concern.

- KM has a generally positive review of MH's approach to capital planning, but there is room for improvement. KM encourages use of a comprehensive model that integrates financial, hydrological, and electric generation components, along with jointly modelling unknown future values by specifying them as random variables.

- MH will benefit from continuing to consider the merits of different rates of capital expansion as the uncertain future for the electricity export market continues to unfold. The Middle Office should play a leading role in approving the process for long term contracts. As a corollary point, KM favours a concrete valuation of a variety of expansion timelines and their implications for the long term financial health of MH.

- MH should move forward cautiously with several potential development sequences to keep its options open in the medium term and obtain the best indication of long term viability for its new capital generation system program.

- MH should complement retained earnings as a risk mitigation measure with other methods of mitigation, including but not limited to additional water storage. MH should adopt a minimum regret strategy to plan for very adverse water situations. It cannot rely only on retained earnings as protection against the severe drought event.

- PUB's role as regulator of MH is to make sure rates are justified, and that MH is not seeking increased rates for recovery of losses for mistakes, errors and inefficiencies. MH must ensure efficiencies are maximized, and that it exercises a discipline of maintaining lowest costs. A more meaningful objective for MH is to minimize costs and create the greatest efficiencies, instead of maximizing net revenues.

18.6.3 Intervener Submissions

CAC/MSOS submits that a number of important contributions have been made by KM resulting from their report and testimony before PUB, notwithstanding the fact that the data and probability distributions contained in Chapter 6 of the KM report are significantly flawed and unreliable. CAC/MSOS recommends that MH adopt the modern scientific approach to risk management outlined by KM as part of MH's risk management strategy and its justification to the PUB for resources to manage risk. CAC/MSOS identified the new risk approach as including:

- The identification of risk factors which have associated probability distributions of outcomes;
- the analysis of the probability distribution of each risk factor based on updated historical data, including the nature of any correlation between risk factors;
- the development of an integrated model of MH's operations that links the risk factors and the financial incomes of interest (net revenues); and
- the performance of Monte Carlo simulations to assess the impact of risk on MH outcomes.

As a result of the flawed analysis in Chapter 6 of the KM report, CAC/MSOS submits that no reliance can be placed on the estimates of the five-year-drought and the seven-year-drought flows produced by KM.

MIPUG identified a number of directional questions upon which it sought to engage during the hearing, related to risk. The questions defined by MIPUG included examination of MH's capabilities, internal organization, policies, procedures, oversight and governance needed to appropriately manage risk.

MIPUG submitted that upon review of all of the evidence on these subjects, MH's approach to risk, while evolving, is appropriate and prudent for a Crown utility.

The concept of risk tolerance was considered by MIPUG's experts. Messrs. Bowman and McLaren concluded that the key benchmark for MH willingness to accept risk in its operations must be the risk tolerance of its Manitoba ratepayers. MH's established risk thresholds do align its risk tolerance to ratepayers and are appropriate, they asserted. Moreover, Bowman and McLaren suggested that where MH pursues long term opportunities which are sufficiently examined and bounded, and provide the means for ratepayers to benefit from the risks of the planned endeavour, through comparatively lower and more stable rates, these actions are viewed as suitable activities underlying regulated rates and are within an acceptable tolerance.

RCM/TREE noted that all of the risk experts appeared to be using out of date Term Sheets as the basis of MH's potential exports revenue position. It also noted that rather than adopting a sceptical review approach, the risk experts accepted the positions adopted by MH in conducting the risk analyses. Particularly troubling, noted RCM/TREE, was the failure of KPMG to involve the PUB in the charting of the risk review which they were engaged to undertake. Finally, the redactions and non-disclosures in the filed material limited the ability of RCM/TREE and its expert Mr. Wallach to properly test the risk information, which limited the benefit of the process for all of the parties.

18.6.4 Board Findings

In addition to the KPMG and KM reports now reviewed, the Board also received other "risk reports". Copies of these reports are on the public record of this GRA.

In these Board findings, the Board provides its findings related to those additional risk reports, as well as its findings with respect to the KPMG and KM reports.

Risk Advisory Reports

Risk Advisory's involvement with MH through the early stages of the then pending 2003/04 drought suggest that MH was not well-prepared to modify its operations in Q3 and Q4 of the 2002/03 fiscal year. The Board notes that MH should have recognized the potential for energy supply problems in the second half of 2002/03 but did not move to deal with these until May of 2003. MH's 2002/03 annual report acknowledged the onset of drought conditions, yet "applauded" the favourable financial results despite those drought conditions.

Risk Advisory's subsequent January 2005 review of energy supply issues did not address the drought recognition aspects and MH's continuation of exports in excess of contract levels. Despite requests, MH has not filed an appropriate post-mortem of the 2003/04 drought event.

Water Stewardship – Peer Review

While the peer reviews on behalf of Manitoba Water Stewardship were generally favourable, the Board notes that the concerns and improvement suggestions are similar to those of other external experts and KM. In particular the Board notes the weak simulation of Lake Winnipeg outflows during low flow years.

Power Export Risks – Dr. N. Bhattacharyya (2007)

The 2007 report by Dr. N. Bhattacharyya flagged some serious issues with respect to the profitability of some of MH's energy trading practices. While MH has attempted to minimize the impact of the results, the Board is concerned that MH may be understating the potential for trading losses.

NYC Allegations

The process of achieving an independent review of the NYC's allegations was very convoluted. The Board looks at this exercise as being largely unsatisfactory. However, it is somewhat disconcerting to find Risk Advisory, ICF and KPMG flagging potential areas of improvement for MH that in many cases mirrored areas that the NYC was critical of, and where in some instances the NYC accused MH of mismanagement.

The contribution of the NYC to the debate on MH's Power Resource Management was significantly flawed. However, it did open a number of avenues to scrutiny. It may well be that MH's Power Sales Operations will have benefited from the public review of MH's operational structure and its business plan. The Board certainly sees that MH has been given insights to a significant number of areas that need improvement.

ICF Report and Presentation

In the Board's view there does not appear to be any direct evidence to support ICF's view that new long-term contracts and new generation and transmission will see a positive impact on domestic rates in the next decade. Publicly available information on contract pricing and conditions is not sufficient to conclude that MH's ratepayers will benefit. Furthermore, substantial capital cost escalation of new generation and transmission projects have not been factored into the process.

Given ICF's forecast of 30-40% reductions to its previous natural gas commodity price forecast, the Board can only conclude that MISO market prices for electricity in ICF's advice to MH (via the Consultant Panel Forecast Updates) will be proportionally lowered. This might confirm that MH's new contract prices are much better than MISO market prices, but increases the concern that MH's opportunity sales will not generate sufficient revenue to cover new plant costs. In an average year, opportunity sales represent more than 50% of MH's overall export sales.

On the basis of information provided, the Board does not share ICF's ready acceptance of the positive risk features associated with MH's long-term contracts. It appears that these features are somewhat favourable in the event of a "worse than the worst recorded" drought, but they do not appear to provide any substantive benefit for drought events of lesser magnitude than the maximum recorded.

ICF did not provide any analyses or evidence on the appropriate rules and volumetric limitations that should be applied to merchant and other short-term trading. The Board is uncertain as to what value can be placed on ICF's conclusions with respect to MH's acceptable management of merchant trading vs. market trading or bilateral sales. All of these activities involve MH's volumetric commitment of at times scarce energy resources without a clear understanding of the financial risks.

Without actually testing MH's modeling inputs/outputs, ICF concluded that these are adequate. This does not provide much assurance to this Board. Rather, it casts doubt on other conclusions that are based on hydrological assessment of the volumetric components of MH's energy supply.

In concluding that MH’s defined five-year drought test is an adequate stress test, ICF is dismissing the possibility of other logically coincidental factors adding to drought costs. In the Board’s view, more evidence would be required to support that conclusion.

In the absence of specific evidence that the impacts of the 2003/04 drought would have been reduced under the new contracts (if the Adverse Water Clause were applicable) the Board does not see much useful drought risk mitigation. Even if the Adverse Water Clause had been applicable, MH’s new generation and transmission capacity may not reduce drought risks if MH continues to aggressively sell all remaining surplus energy.

KPMG Report

When the Board looks at KPMG’s contribution to this hearing on risk issues, the Board concludes that the overall time, opportunity and monetary resources available to KPMG did not result in the due diligence review that the Board expected or that MH might have found useful going forward. Certainly, the Board would have expected a more in-depth analysis of MH’s actual water resource utilization and the market price scenarios during 2003/04 and 2006/07.

KPMG did suggest that MH’s antecedent forecasting process could be improved by adding hydrological components to the overall modeling system. However, when asked to define the specific components that should be added, KPMG indicated that it did not have the hydrological expertise necessary to provide those factors.

When revisiting MH’s various development scenarios, KPMG relied totally on MH’s existing models and MH’s energy pricing forecast. KPMG did not see its role as challenging MH’s operational decisions or MH’s interpretation of the energy market.

With respect to MH’s Middle Office – Front Office relationship, KPMG was concurrently retained to define the appropriate Middle Office role and structure to best augment MH’s Power Sale Office operation. This supplementary report offered useful direction on Middle Office staffing and responsibilities. However, it did not provide any significant insights on the Front Office operation under drought situations such as existed in 2003/04 or on market situations such as existed in 2009/10.

In the Board's view, the value of KPMG's review was constrained by the consultant's exclusive reliance on MH's modeling assumptions and MH's export price forecasting. This degree of reliance raises concerns about the independence of KPMG's review and advice.

KPMG's acknowledgement that KPMG did not look to challenge MH's operational decisions, (presumably due to a lack of hydrological expertise) or to challenge MH's management decisions with respect to export market price forecasts does not speak well for KPMG's conclusions that "MH demonstrated prudent risk management". This also raises questions about how KPMG could dismiss most of the NYC allegations as having little or no foundation.

MH indicated that KPMG was only asked to review post-2006 operations. As such, the Board is at a loss to understand how a risk review could be accomplished without serious attention to the most significant drought in the last decade.

In a similar vein, the Board concludes KPMG did not fully address the issue of the SPLASH model's over-statement of longer term hydraulic generation as a result of perfect foresight.

KPMG has implied that MH's operations are conservative but did not look at MH's habit of typically selling up to 115% of its annual hydraulic generation and the risk of winter buy-backs relative to summer off-peak sales. The Board sees MH's actions as being somewhat aggressive rather than conservative in practice.

The Board is concerned that KPMG did not critically explore the inter-relationship of drought risks and price risks, yet concluded that MH has a "conservative" approach to power resource management and marketing.

Further, KPMG acknowledged that it did not possess the technical expertise to actually carry out:

- an independent review of hydrological issues and how these should be integrated into MH's forecasting process;
- an independent assessment and/or back-testing of MH's HERMES or SPLASH models; and
- a comparative analysis or critique of MH's market forecasts of the value of export or import energy.

In the Board's view, many of KPMG's observations and recommendations would require a high level of expertise in hydrology, water supply management modeling and energy market pricing.

Independent Consultant (KM)

The KM report provided much useful insight into MH's energy supply and power sales operations and to the NYC allegation with respect to those operations. It is the Board's view is that KM's review usefully re-defined the circumstances that were addressed by various MH consultants and provided a degree of clarity on many issues.

While KM's overall process of examining the NYC allegations was constrained by various legal challenges and the apparent need for extensive data redactions, the Board believes that useful information was gleaned from the various opinions on the validity of the allegations. There has been a strong indication that MH has or intends to strengthen the operational structure of MH's power supply and sales ventures. A stronger Middle Office with a more clearly defined Front Office interface seems to be in the making.

Various reports have identified concerns and weaknesses in MH's marketing strategies, particularly as they were enacted in 2003/04 and in 2006/07. Despite MH's current reluctance to acknowledge the potential need for operational improvement and a written Drought Preparedness Plan, KM (and other experts) were looking forward to MH's documentation of potential drought risk mitigation strategies in that plan. The Board still expects MH to file such a written plan.

Concerns raised by the NYC about the very limited number of in-house experts to run MH's key models and to direct power sales operations apparently have some merit. Most of external experts have alluded to the need for more formal documentation of these key models and the need for regular independent back-testing of operational results.

The Board sees merit in some of KM's findings on the NYC allegations, but does take issue with the narrow interpretation placed on some concerns and the reliance on other experts' opinions.

When KM (and others) suggested that MH's five-year-drought analysis represents an adequate valuation of MH's overall risk, the Board would have expected that KM (and others) would have done a detailed assessment of both the five-year- and seven-year-droughts. That apparently was not the case. KM performed various single-year-drought assessments (which conceivably would have mirrored the worst year in the five- or seven-year-droughts), but did not specifically evaluate the five-year-drought.

KM suggested that the idea of non-financial water reserves (the holding back of water against the risk of a future drought) in addition to financial reserves (adequate retained earnings) merits serious consideration, but the Board has not seen any detailed analysis of how such a reserve would beneficially function under actual historical drought scenarios.

19.0.0 COST OF SERVICE

19.1.0 OVERVIEW

The 2006 Cost of Service Review led to Board Order 117/06, which contained the Board's findings on various aspects of MH's cost allocation. MH's 2008 General Rate Application included COSS08 (prepared by MH in Aug. 2007) which only partially complied with Board Order 117/06.

As directed in Board Order 116/08, MH filed a March 2009 version of COSS08 that was in large part compliant with that Order. MH, however, continued to object to specific components of the Board Directives in Board Order 116/08. These were:

- a single export class with fully allocated embedded costs in addition to direct assignment of fuel and power purchase costs;
- direct assignment of fixed and variable thermal generation costs to exports;
- use of actual prior year export pricing instead MH's IFF forecast pricing;
- assignment of all NSB/MISO/Trading Desk costs to the export class; and
- assignment of all DSM costs to the export class.

MH has not in recent years proposed any rate increase differentials based on revenue to cost coverage (RCC) ratios for Residential and General Service Small/General Service Medium/General Service Large. Only Area and Roadway Lighting has seen rate freezes to reduce its RCC.

In the current General Rate Application MH filed COSS10 which deviated in a number of allocation aspects from Board Order 116/08.

In early 2010, MH filed COSS11 based on the 2010/11 fiscal year. However, MH recommended that both COSS11 and COSS10 be received by the Board for information only.

In light of the post-COSS11 industrial load reductions and the potential for lower export revenues, there may well be the need for a COSS12 or COSS13 to be filed before a full review of the Cost of Service is usefully undertaken.

MH has, subsequent to filing its GRA, engaged an external consulting service to “review the Cost of Service methodology for consistency with cost causation, utility economics and the range of regulatory practices in North America, and pursuant to that review, to make appropriate recommendations with respect to either maintaining or varying those methodologies.”

MH did file the preliminary Terms of Reference with the Public Utilities Board in early 2010. The final terms of reference of this study have not yet been shared with the Board.

The Board expects that MH will present the “Cost Of Service Review” findings along with a detailed comparison to the March 2009 PCOSS08. Proposed changes should be accompanied by an item-by-item detailed explanation, justification, quantification and rate impact explanation. Likewise, a similar comparison should be provided for any marginal cost based cost of service study scenarios.

19.2.0 COMPARISON OF COSS08 TO COSS10 AND COSS11

The hearing record contains a line-by-line comparison of revenues and costs associated with the single export class for each of the above COSSs. That information illustrates the strong correlation between unit export revenue and the net export revenue available for customer class subsidies.

19.3.0 GENERATION AND TRANSMISSION COSTS

Generation and transmission costs (assigned and allocated) in the various COSS scenarios flow to domestic and export classes.

It is noteworthy that the two most recent versions of COSS11 show a significant increase in the domestic cost allocations compared to the PUB-approved March 2009 COSS08. Much of this increase results from the reduction in costs directly assigned to exports.

MH's COSS11 movement of all thermal costs and about 50% of NEB/MISO/Trading Desk costs to domestic classes involves a $64M shift in costs to domestic customers which is not in compliance with the Board's directives and the March 2009 COSS08.

The proportion of allocated generation and transmission costs going to exports compared to domestic remains constant at 60-70%. This disparity in allocated costs therefore seems to be largely related to the treatment of HVDC and other transmission costs.

19.4.0 DISTRIBUTION COSTS

In COSS10 and COSS11 the total allocated costs to sub-transmission/distribution plant/distribution services appears to have grown in step with sales. The cost per kWh has remained fairly constant at 2.2 to 2.3¢/kWh since 2007.

19.5.0 MARGINAL COST TREATMENT OF COSS

In Board Orders 117/06 and 116/08, MH was directed to create a Marginal Cost (MC)-based COSS and examine means to reflect environmental values within such an MC-COSS. These directives have, to date, not been adequately addressed. Initial attempts by MH to build a free-standing version of an MC-COSS were unsuccessful.

A considerable difficulty exists in defining the appropriate MC in an export market-driven utility where the actual export price-based MC could be viewed as commercially sensitive and hence confidential. This means that MC must be replaced by a proxy or some variation of embedded costs.

19.6.0 COSS TREATMENT OF NET EXPORT REVENUE

In the extended period of relatively high export prices prior to 2008/09, the impact of net export revenue credits to various domestic classes was substantial. By calculating the credit on the basis of total class costs, Residential and General Service Small receive a favourable adjustment to their Revenue Cost Coverage (RCC) ratios.

With the more recent decline in export prices, the available net export revenue (to be credited to domestic consumers) has dropped markedly. With Uniform Rates and the Affordable Energy Programs flowing largely to the Residential class, its RCC should increase relative to other classes.

Despite this treatment, Residential RCCs have remained in the 0.90 to 0.95 range compared to the GSL 30 to 100 and GSL >100 subclasses' RRCs, which are within a 1.05 to 1.10 range.

19.7.0 COSS TREATMENT OF HVDC COSTS

In recent Power Resource Plans MH indicated that new HVDC transmission costs will not be assigned or allocated to the export class. This seems to go well beyond the previous COSS process that treated a portion of the existing HVDC as a generation asset to be cost shared by export on a net export share basis. While Bipole III has reliability benefits for domestic customers, Bipole III is also needed to fulfil export commitments.

It is not clear whether COSS10 and/or COSS11 have made any adjustment to how Bipole I and II costs have been dealt with to date.

MH seems to be departing from true cost causation principles. The on-going functional usage of transmission by exports is not being considered.

19.8.0 INTERVENER POSITIONS

19.8.1 CAC/MSOS

To date CAC/MSOS has opposed the use of current COSS methodologies in rebalancing or setting differential rate increases for MH domestic customers. More robust marginal cost based analysis is suggested.

19.8.2 MIPUG

In MIPUG's view the current methodologies adequately calculate the class RCCs and should be used to assign lower differential rates to the GSL >100 class.

19.8.3 RCM/TREE

As in the past, RCM/TREE continues to support the use of an MC-based analysis in the cost allocation process and in rate-setting. With respect to low income and other social policy issues, it is RCM/TREE's position that the PUB unquestionably has jurisdiction to impose such an approach.

19.9.0 BOARD FINDINGS

MH has chosen not to seek differential class rate increases other than for Area and Roadway Lighting. MH's principles of rate design and cost allocation should be kept current. That said, the Board's position should not be interpreted to imply any support for the Cost of Service methodology changes employed by MH in PCOSS10 and PCOSS11.

In previous Board Orders, MH has been directed to treat all exports as a defined business venture obligated to share fully in the Utility's embedded costs. The Board has not accepted and does not accept the concept of any exports being a free by-product of domestic power operation.

Exports come with a cost, and that cost needs to be recognized in calculating net export revenue and in developing a business plan for new generating stations and transmission assets.

Reliability benefits associated with the HVDC system flow to export customers as well as domestic customers. Allocation of zero Bipole III costs to exports ignores these benefits and the role that Bipole III plays in facilitating exports from northern generation.

In the Board's view, MH's Export Business Model cannot transfer all operational and market risks to domestic customers. Because export contracts and opportunity sales carry greater risks than domestic sales, such export sales must provide a contribution to MH's fixed costs.

As the Board anticipates that the external Cost of Service review may not be available before mid-2012, there may be merit in a separate COSS review hearing if MH is seeking changes to the currently approved Board methodology.

Should marginal cost be a significant consideration in a future COSS, the Board's review would require MH to fully disclose its derivation of MC components. Whether any such disclosure would be on the public record will be a procedural matter to be determined.

20.0.0 RATE DESIGN

In addition to various rate matters addressed in section 3.0.0 of this Order, there are other rate and rate design issues to be addressed.

20.1.0 INVERTED RATES

Board Order No. 116/08 directed MH to file a report on Inverted Rates (in particular dealing with electric heating customer impacts) by January 15, 2009. There has been no action by MH to date with respect to that directive. MH has acknowledged that a rate accommodation will be required for electric heating customers, but has not provided any specific proposals that would mitigate a significant inverted rate strategy.

Aside from the Residential class, where prior to the Board's interim April 1, 2011 rate Order, there was only a modestly higher second block rate, the only movement toward inverted rates and toward eliminating the rate discount for higher levels of consumption appears to lie in the multi-year freeze of demand charges. However, for GSS/GSM customers energy rate adjustments are still applied on an equal percentage basis to all energy blocks in the ongoing consolidation of GSS and GSM subclasses. There has been no indication of the elimination of declining block prices for these subclasses.

20.2.0 RATE REBALANCING

MH continues to hold the demand charge at constant levels and is seeking the entire approved class rate increase via the energy charge. This process may have a limit short of fully rebalancing rates, but MH has not defined it to date.

20.3.0 CLASS CONSOLIDATION

MH continues to move the GSS and GSM subclasses toward a common rate structure. Apparently this process will be completed, within a few years, on a revenue neutral basis.

20.4.0 WINTER RATCHET ELIMINATION

The elimination of the Winter Ratchet by MH in lieu of the introduction of time-of-use may be useful in:

- consolidating GSS and GSM subclasses (only GSM had a winter ratchet);
- rate rebalancing (average demand revenues will be reduced for specific customers and subclasses and the resulting cost will be offset by higher energy charges);
- Limited Use Billing Demand (could see some reversions to normal billing); and
- Demand Concessions (lower demand charges for some GSM and GSL customers could mitigate impacts of economic downturns).

MH did not file a formal application for the elimination of the Winter Ratchet or provide a report detailing its impacts, but has proceeded with the elimination of this rate feature.

20.5.0 LIMITED USE BILLING DEMAND

The Limited Use Billing Demand (LUBD) program was initially developed for low load factor customers who were heavily impacted by the application of the winter ratchet. The LUBD in effect allowed customers with an 18% or lower load factor to opt for paying higher energy charges and reduced demand charges.

Contrary to initial expectations, LUBD attracted many seasonal customers with high summer/low winter demand. The program was not intended to be revenue neutral and now has an annual utility cost impact of $200,000 to $300,000.

20.6.0 BASIC MONTHLY CHARGE

The Board has denied MH's recently proposed reduction in the Basic Monthly Charge (BMC), citing a lack of appropriate justification. This is a cost-causation issue, because the current BMC does not nearly meet allocated customer costs.

20.7.0 TIME-OF-USE BILLING

MH has not provided any update on the status of time-of-use (TOU) rates. The elimination of the Winter Ratchet may have accomplished some time-of-use objectives. The Board's request for a September 30, 2008 planned implementing strategy report has not been answered. The Board understands that MH has been consulting MIPUG members on this issue. The content and extent of these consultations should be provided to the Board.

MIPUG's industrial customers are the most likely initial targets for TOU given the presence of appropriate metering. However, in light of current export market prices, TOU may actually have negative revenue impacts for MH. This should be considered further.

20.8.0 AREA AND ROADWAY LIGHTING

As in the previous GRA, MH's rate application did not call for ARL rate increases. The Board concurred with this in its approval of the interim and finalized rate increases.

20.9.0 ENERGY INTENSIVE INDUSTRY RATE

MH initially filed and then withdrew a revised proposal for the Energy Intensive Industry Rate (EIIR) which was being considered by MH's Board of Directors in January 2011. Beyond an indication of further consultations with industry there has been no further update on MH's intended actions.

The Board has some concerns about this issue remaining unaddressed. Until MH comes up with a revised program, the existing Board Directives on the nature of a future EIIR and a Service Extension Policy would seem to represent the current reality for MH and to new customers.

The Board notes that uncertainty with respect to the EIIR may not be attractive to potential new industrial loads.

20.10.0 SERVICE EXTENSION POLICY

Since the Board's last Order on EIIR, MH has been silent on the future of the service extension policy. The service extension policy issue is seen by the Board as independent of the EIIR. Nonetheless, the service extension policy has serious implications for industrial customers even in the absence of EIIR, especially for potential remote loads.

20.11.0 INTERVENER POSITIONS

20.11.1 CAC/MSOS

The Rate Design interests of CAC/MSOS can be succinctly indicated as being primarily focused on:

- Inverted Rates (CAC/MSOS has concerns about winter heating);
- Basic Monthly Charge (CAC/MSOS is in favour of reductions for the benefit of low-income consumers); and
- Temporary Billing Demand Concessions (CAC/MSOS is opposed to granting permanent relief as requested by MH).

20.11.2 MIPUG

The Rate Design interests of MIPUG can be succinctly indicated as being primarily focused on:

- Inverted Rates (MIPUG needs clarification before it can finalize a position);
- Rate Rebalancing (MIPUG is opposed to larger energy rate increases);
- Time-of-Use Rates (MIPUG thinks they may be of limited benefit but would want to receive a detailed study of any MH proposal);
- Energy Intensive Industry Rate (MIPUG appears satisfied with MH’s consultative approach even if no proposal has been publically advanced); and
- Temporary Billing Demand Concessions (MIPUG strongly supports MH’s request for “forgiveness” of the temporary deferral relief).

20.11.3 RCM/TREE

The Rate Design interests of RCM/TREE can be succinctly indicated as being primarily focused on:

- Inverted Rates (RCM/TREE want aggressive action, including higher winter thresholds for electric heating);
- Basic Monthly Charge (RCM/TREE submits that this should be eliminated as soon as possible); and
- Time-of-Use Rates (RCM/TREE is very supportive of MH advancing such rates).

20.11.4 City of Winnipeg

The ongoing rate and rate design interest for the City of Winnipeg was Area and Roadway Lighting, with an emphasis on limiting any rate increases.

20.12.0 BOARD FINDINGS

The Board notes that MH's responses on the various special rate issues remain outstanding and should receive more timely attention. The Board invites MH to provide all stakeholders (including the Board) with an overall strategy to co-ordinate the changing of rate structures for MH's various customer classes.

The Board requires MH to file preliminary reports (and status updates on):

- Inverted Rates, with a view to creating a significantly higher-priced second energy block, but providing an accommodation to electric heat customers, some of which do not have access to natural gas for heating;
- GSS and GSM Class consolidation with a view to defining the end-product and the specific timeframe for completion;
- Demand/Energy Rate Rebalancing with a view to defining the optimum balance and timeframe to achieve that balance through the allocation of Class Rate increases to the energy component;
- Time-of-Use Rates with a view to applying these in the near future to Top Consumers and industrial customers that already have the necessary metering capability;
- Limited-Use Demand billing with an update of the continued need for this rate in light of the elimination of the Winter Ratchet;
- the Energy Intensive Industry Rate, with justification for either abandoning the rate proposal or providing an alternative on-peak rate scenario as directed in Board Order 112/09; and
- the Service Extension Policy, including a proposal for the Board's review and possible acceptance in accordance with Order 112/09.

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.

21.0.0 IT IS THEREFORE ORDERED THAT:

1. A 1.9% average consumer rate increase for all of MH's domestic customer classes (except Area and Roadway Lighting) effective April 1, 2010 **BE AND IS HEREBY APPROVED AS FINAL**;

2. A 2.0% average consumer rate increase for all of MH's domestic customer classes (except Area and Roadway Lighting) effective April 1, 2011 **BE AND IS HEREBY APPROVED AS FINAL**;

3. MH's requests to finalize a 2.9% average consumer rate increase effective April 1, 2010; a 2.0% average rate increase effective April 1, 2011; and a further 0.9% average rate increase effective August 1, 2011 **BE AND ARE HEREBY DENIED**;

4. MH recalculate and refile, for Board approval, a schedule of rates reflecting a 1.9% average increase for all customer classes (except Area & Roadway Lighting) effective April 1, 2010, together with all supporting schedules including proof of revenue and customer impacts;

5. MH recalculate and refile, for Board approval, a schedule of rates reflecting a further 2.0% average rate increase for all customer classes (except Area & Roadway Lighting) effective April 1, 2011, together with all supporting schedules including proof of revenue and customer impacts;

6. MH calculate and file, for Board approval, a new interim rate that quantifies the difference between the April 1, 2010 and April 1, 2011 interim rates and the rates

finalized in this Order, together with all supporting schedules including proof of revenue and customer impacts;

7. MH is to forthwith advise this Board and the parties to this GRA of MH's intention respecting a GRA for the 2012/13 fiscal year;

8. MH is to calculate, and file for Board approval, a deferral account that tracks the difference between revenues calculated pursuant to the interim rates (in Orders 18/10; 30/10 and 40/11) and the rates finalized in this Order, together with accrued interest at MH's short-term borrowing rate;

9. All weekly Surplus Energy Program interim *ex-parte* rate orders – from Order 67/08 up to and including all SEP Orders issued prior to this Order – **BE AND ARE HEREBY APPROVED AS FINAL**;

10. Curtailable Rate Program Orders from Order 46/09 until current – including Order 63/11 – **BE AND ARE HEREBY APPROVED AS FINAL**;

11. MH's request that the Temporary Billing Demand Concessions granted pursuant to Order 126/09, be made permanent, and forgiven, under the program **BE AND IS HEREBY DENIED**.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE CA"
Chairman

"HOLLIS SINGH"
Secretary

Certified a true copy of Order No. 5/12 issued by The Public Utilities Board

Secretary

LIST OF ABBREVIATIONS

AC	-	Alternating Current
AEF	-	Affordable Energy Fund
AOCI	-	Accumulated Other Comprehensive Income
ARL	-	Area and Roadway Lighting
BMC	-	Basic Monthly Charge
CAC/MSOS	-	Consumers Association of Canada/Manitoba Society of Seniors
CBO	-	Community-Based Organization
CCCT	-	Combined-Cycle Combustion Turbine
CCX	-	Chicago Climate Exchange
CEF	-	Capital Expenditure Forecast
CFS	-	Cubic Feet per Second
CJA	-	Capital Justification Addendum
CO_2	-	Carbon Dioxide
COSS	-	Cost-of-Service Study
CRD	-	Churchill River Diversion
CRP	-	Curtailable Rate Program
DC	-	Direct Current
DSM	-	Demand-Side Management

EFT	-	Equivalent to Full-Time
EIIR	-	Energy Intensive Industrial Rate
EIS	-	Energy In Storage
FERC	-	Federal Energy Regulatory Commission (United States)
GAAP	-	Generally Accepted Accounting Principles
GILT	-	Grants in Lieu of Taxes
GJ	-	Gigajoule
GRA	-	General Rate Application
G.S.	-	Generating Station
GSL	-	General Service Large (Customer Class)
GSM	-	General Service Medium (Customer Class)
GWh	-	Gigawatt-Hour
HTR	-	Hard-to-Reach
HVDC	-	High-Voltage Direct Current
ICF	-	ICF International (Consulting Firm)
IFF	-	Integrated Financial Forecast
IFRS	-	International Financial Reporting Standards
KCN	-	Keeyask Cree Nations
KHLP	-	Keeyask Hydropower Limited Partnership

kV	-	Kilovolt
kVA	-	Kilovolt-Ampere
kWh	-	Kilowatt-hour
KM	-	Drs. Kubursi and Magee (Independent Consultants & Report Authors)
KPMG	-	KPMG (Accounting Firm)
LICO	-	Low Income Cut-Off
LIEEP	-	Lower Income Energy Efficiency Program
LUBD	-	Limited Use Billing Demand
LWR	-	Lake Winnipeg Regulation
MC	-	Marginal Cost
MCC	-	Manitoba Chamber of Commerce
MC-COSS	-	Marginal Cost-based Cost of Service Study
MH	-	Manitoba Hydro
MHA	-	Manitoba Housing Authority
MIPUG	-	Manitoba Industrial Power Users Group
MISO	-	Midwest Independent (Transmission) System Operator
MP	-	Minnesota Power
MRC	-	Marginal Resource Cost

MW	-	Megawatt
NBF	-	National Bank Financial
NCN	-	Nisichawayasihk Cree Nation
NERC	-	North American Electric Reliability Corporation
NFAAT	-	Needs For And Alternatives To
NEB	-	National Energy Board
NPV	-	Net Present Value
NSP	-	Northern States Power
NYC	-	New York Consultant
O&A	-	Operation and Administration (Expenses)
OL	-	(Financial) Outlook
OM&A	-	Operation, Maintenance and Administration (Expenses)
PACT	-	Program Administrator Cost Test
PCOSS	-	Prospective Cost of Service Study
PRP	-	Power Resource Plan
PUB	-	Public Utilities Board
RCC	-	Revenue to Cost Coverage (Ratio)
RCM/TREE	-	Resource Conservation Manitoba (now Green Action Centre) / Time to Respect Earth's Ecosystems

RIM	-	Rate Impact Measure
RSM	-	Rate Stabilization Mechanism
RSR	-	Rate Stabilization Reserve
SCCT	-	Single-Cycle Combustion Turbine
SCT	-	Societal Cost Test
SEP	-	Surplus Energy Program
TPC	-	Taskinigahp Power Corporation
TOU	-	Time-of-Use (Ratio)
TRC	-	Total Resource Cost
WCC	-	Western Climate Coalition
WPLP	-	Wuskwatim Power Limited Partnership
WPS	-	Wisconsin Public Service

APPENDIX A - APPEARANCES

R. Peters A. Southall	Counsel for The Manitoba Public Utilities Board (Board)
M. Boyd P. Ramage O. Fernandes	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 (CAC/MSOS)
A. Hacault	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson (np)	Representing *Manitoba Keewatinowi Okimakanak.* (MKO)
W. Gange P. Miller	Counsel for Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Pambrun	Counsel for the City of Winnipeg
J. Rath D. Coad	Southern Chiefs Organization (SCO)
G. Wood	Independent Experts (KM)

(np)- not present at the hearing

APPENDIX B – WITNESSES FOR MANITOBA HYDRO

MH Personnel

V. A. Warden	Vice-President, Finance & Administration and Chief Financial Officer
H. M. Surminski	Senior Resource Planning & Special Studies Engineer, Resource Planning and Market Analysis Department
K. R. Wiens	Division Manager, Rates & Regulatory Affairs
D. Cormie	Division Manager, Power Sales and Operations Division
L. J. Kuczek	Vice-President, Customer Care and Marketing
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

Interveners of Record

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

Manitoba Industrial Power Users Group (MIPUG)

Manitoba Keewatinowi Okimakanak (MKO)

Resource Conservation Manitoba (now Green Action Centre)/Time to Respect Earth's

Ecosystems (RCM/TREE)

City of Winnipeg (CITY)

Southern Chiefs Organization (SCO)

APPENDIX D – INTERVENER AND INDEPENDENT WITNESSES

Intervener Witnesses

CAC/MSOS

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

MIPUG

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

RCM/TREE

P. Chernick	President, Resource Insight Inc
J. Wallach	Vice-President, Resource Insight Inc.
R. Colton	Fisher, Sheehan & Colton

Independent Expert Panel

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

APPENDIX E - PRESENTERS

Mr. Art Carriere (written only)	Citizen
Mr. Allan Ciekiewicz	Citizen
Mr. Art Derry	Bipole III Coalition
Mr. David Forsyth	Gerdau Ameristeel Corporation
Mr. John Gray	Citizen
Mr. Norm Gruhn (written only)	Citizen
Mr. Lynn Jones (written only)	Citizen
Mr. Mark Shirley (written only)	COO, Amsted Rail
Dr. Leonard Simpson and	Citizen
Mr. Blair Skinner	Citizen
Mr. Graham Starmer	Manitoba Chamber of Commerce
Mr. Bill Turner	Canexus/ Chair, Manitoba Industrial Power Users Group