MANITOBA	Order No. 117/06
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	August 2, 2006

Before: Graham Lane, C.A., Chairman
Robert Mayer, QC, Vice-Chairman
Len Evans, LLD (Hon.), Member
Kathi Avery Kinew, Ph.D., Member

A REVIEW OF MANITOBA HYDRO'S COST OF SERVICE STUDY METHODOLOGY AND OTHER MATTERS

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APPENDICES

1.0 Executive Summary

By this Order, the Public Utilities Board (Board) directs Manitoba Hydro's (MH) to amend its Cost of Service Study (COSS) methodology in advance of filing a two-year General Rate Application (GRA) for amended customer rates. In directing MH to file a new GRA, the Board shares MH's concerns with respect to the utility's low equity (retained earnings) position relative to its business risks. As well, by this Order the Board provides other directions that may affect rates when next amended.

With this Order, the Board accepts MH's contention that a fundamental change has occurred to its operations and prospects with the advent of higher unit export prices brought about partly as a result of revised export trading rules and a concurrent new ability to undertake arbitrage sales. The Board also shares MH's concern that low-priced electricity consumption in Manitoba may displace higher export sales opportunities as well as lead to higher customer bills while inhibiting potential carbon dioxide (CO_2) emissions reductions on a more global basis.

New export market rules provide for export prices based on the marginal costs of production of MH's American export customer members of the Mid-Continent Area Power Pool (MAPP) and the Midwest Independent System Operator system (MISO). As a result of both the new rules and the higher natural gas prices of July 2005 through January 2006, which drove up marginal costs and export prices in fiscal 2005/06, for the first time average export prices exceeded the average rate charged to Manitoba customers. When export prices exceed domestic rates, increased Manitoba consumption reduce MH's export sales opportunities, net export revenues and MH's net income.

With MH still well below the Board-approved equity target (ratio of MH's retained earnings to aggregate debt), and with extant risks commensurate with the complexity and magnitude of

Manitoba's largest utility, realizing lower net income than currently forecast would likely mean higher domestic rates in the future.

In short, when there are export opportunities at prices in excess of rates charged Manitoba customers, MH can increase its overall revenue and net income by selling energy to its export clients rather than to the domestic market. When it does not, i.e. MH sells the energy to a domestic customer, which is always its first priority, overall MH's revenue and net income are lower than would otherwise be the case.

Linkages between export potential, Manitoba consumption, and average industrial rates below average export prices prompted MH to express concern related to large energy-intensive firms, particularly those using energy as a feedstock for industrial processes. By this Order, the Board directs MH to engage in public consultations and propose a new industrial class for new high consumption firm customers with to-be-defined characteristics and rates.

Establishing a new industry class to potentially receive market-based electricity pricing is a significant public policy issue, and one extending beyond the regular scope of the Board's regulatory oversight. Considerations should include economic and social issues, and thus require the input of society including, in particular, government and industry.

The Board seeks to assure itself that MH's rate design and rates are consistent with the pursuit of the environmental objectives of *The Sustainable Development Act* (SDA). As a further response to the risk that higher domestic consumption poses for net income and domestic rate levels, MH is directed to bring proposals forward to the Board to eliminate declining block rate schedules, and to introduce inverted and time of use rates, initially for large volume non-residential customers. Energy efficiency presents the potential for a virtuous circle, wherein lower domestic consumption results in reduced customer bills, higher MH aggregate net export revenue and net income, and lower carbon emissions by MH's American export customers.

The Board fully recognizes the responsibilities placed on public agencies, including MH and the Board, by the SDA. To assist in the review of future rate applications, MH is directed to provide the Board with supplemental information with respect to marginal and environmental costs associated with its domestic and exports sales, factors currently neither measured nor reported. The Board intends to take into account supplemental information related to marginal costs and carbon emissions, along with other factors, in evaluating future MH rate applications.

The Board understands that diesel commodity costs have increased since the Board's interim diesel rate amendments, and directs MH to file with the Board a new diesel rate application with respect to service to the four northern communities provided electricity through diesel generation by September 30, 2006. In the interim, MH's recommended treatment of the diesel customer class in the COSS is approved.

By this Order, the Board requires actions and filings by MH covering a wide range of complex issues and matters. The Board acknowledges the time and effort required of MH to meet the Board's directions, and will consult with MH and registered interveners to establish a reasonable GRA timetable. The Board anticipates that a public hearing will take place no later than May or June 2007, with any rate adjustments arising out of the process taking effect no later than August 1, 2007 and April 1, 2008.

COSS Framework

The central focus of the Board hearing held in May and June 2006, at which MH and registered interveners representing MH's customer classes and environmentalists participated, was a review of various COSS alternatives. The primary origin of the COSS application and resultant directions rests with recognition of the growing magnitude of MH's export revenues.

COSS allocates MH's revenues and costs between customer classes. COSS is employed as a tool in evaluating customer class rates, serving as one test of the fairness of rates between customer classes. A COSS is normally filed with each GRA and, together with the proposed revenue requirement and rate design, and other pertinent information, forms the background supporting rate setting.

By this Order, the Board approves MH's recommended COSS methodology subject to a number of important amendments, to be modeled by MH prior to the Board confirming its direction, including:

- the addition of one export customer class rather than two export customer classes as recommended by MH, with revenues and costs allocated similarly to the approach for domestic customer classes, including the assignment of direct and indirect costs, both fixed and variable. The new export customer class will reflect the importance of export sales to MH;

- inclusion as a customer class within the overall COSS of the four northern communities provided electricity through diesel-generation as recommended by MH; and

- net export revenue is to be derived through deducting from export sales direct, indirect, fixed and variable costs allocated to the export customer class, the estimated cost of the uniform rate program, DSM costs and forecast draws on any Fund established pursuant to the Winter Heating Cost Control Act (Bill 11).

While the base COSS model will continue to rely on prospective historic embedded costs, information reflecting marginal costs and the value of carbon emissions representative of domestic energy consumption will also be considered. COSS and supplementary information with respect to marginal costs and carbon emissions is to be filed with a reconciliation linking

COSS, the supplementary information and a “normalized” financial forecast drawn from MH’s electricity Integrated Financial Forecast (IFF).

The Board has also provided a number of directives to MH with respect to various other reports and information to be filed with the Board over the coming months.

The Board reiterates that COSS represents but one element of the overall rate setting process joining considerations of environmental costs, marginal costs and special circumstances with embedded costs, revenue requirement and rate design.

2.0 Introduction

In response to the Board’s direction, MH filed an application in November 2005 for a revised COSS. The Board heard the application through a public hearing extending over eleven days during the months of May and June 2006, concluding on June 2, 2006. Transcripts of the proceedings may be accessed either at the Board’s offices or through the Board’s website (www.pub.gov.mb.ca) and provide the testimony, views and positions of all parties participating in the hearing.

Six interveners represented various MH customer classes, and evidence was heard from three independent expert witnesses and a panel of MH officials. The Board was assisted by Board Counsel, two professional advisors (a partner from the accounting firm PricewaterhouseCoopers, and a professional engineer), and Board staff. As further identified in appendices to this Order, the interveners were:

a) Consumers’ Association of Canada (Manitoba) Inc. and Manitoba Society of Seniors (CAC/MSOS);

b) Canadian Centre for Energy Policy (CCEP);

c) City of Winnipeg (City);

d) Manitoba Industrial Power Users Group (MIPUG);

e) Manitoba Keewatinook Ininew Okimowin (MKO); and

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

While the hearing focused primarily on COSS matters, COSS and the other components of rate setting are inter-related and this inter-relationship is complex. Therefore, over the course of the hearing, the Board heard evidence with respect to a number of other complex issues including financial forecasts, operating approaches and plans.

To better understand this Order and its directions, the purpose and nature of COSS, the objectives for the hearing, and the inter-relationship between the three major components of rate setting (revenue requirement, rate design and COSS), a background outline is required. As well, it will be helpful to review the broader context in which COSS operates and the significance of MH to the Province and to Manitobans.

Since the 1970s, MH has conducted COSS's based on embedded costs. Though there have been changes to the methodology over the years, these were mainly due to the availability of better information. The key features of MH's COSS methodology have remained relatively constant over the years.

In Board Orders 101/04 and 143/04, which resulted from MH's 2004/05 GRA hearing, the Board directed MH to file four different COSS, those being:

a) the then-current methodology (which had no export customer class);

b) a methodology with an export class recommended by National Economic Research Associates (NERA), a consultancy firm engaged by MH;

c) a methodology based on generation vintaging; and

d) MH's preferred methodology (which was not required to be any of the other models).

COSS neither determines nor changes rates but serves as an assist in rate setting. The COSS is a tool used to assist in evaluating whether customer classes pay their fair share of costs through rates, and serves as one test of the fairness of rates between customer classes. Rate changes begin with the establishment of MH's annual revenue requirement, that being the level of revenue required from electricity customers to provide for all costs as well as make a contribution to retained earnings. Rate design includes the development of revenue by customer class, energy consumption blocks, the distribution of revenue requirement between demand and energy uses, and minimum customer bills.

In preparing a COSS, MH utilizes prospective revenue and expenditure forecasts from its IFF which is based on the Corporation's financial statements. The current COSS assumes median water flows, but not necessarily normal reservoir levels and export pricing circumstances. Water levels and expected export prices play an important role in the estimate of projected net export revenue.

Two COSS models are usually developed for a GRA, the first reporting the RCC for each customer class prior to the proposed rate change, the second reflecting the proposed rate changes.

The COSS determines the revenue cost coverage ratio (RCC) for each customer class by comparing class revenue, both before and after allocated net export revenue, to allocated costs.

If a customer class RCC is within the range of 95% to 105%, that customer group is generally considered to be within the zone of reasonableness (ZOR), and the rates for the class are generally understood to be reasonable and fair.

Historically, the RCC ratios for some customer classes, after the allocation of net export revenue, have consistently been outside of the ZOR. In the few MH hearings held before the Board over the past ten years (reference: Orders 7/03, 101/04 and 143/04), interveners sought a commitment to bring all customer classes into the ZOR within a reasonable period of time. The Board, in Order 143/04, suggested this to be a reasonable objective.

There are several reasons why the rates of all customer classes are not within the ZOR:

- MH filed only two rate applications over the past ten years, providing few opportunities for rate changes;

- COSS is only one tool in rate setting and other factors enter into MH's and the Board's consideration. For example, MH's 2004 rate application was brought forward during a period of drought when the Corporation experienced significant losses, and the Board approved across-the-board rate increases despite the RCCs for certain customer classes being outside the ZOR. Orders 101/04 and 143/04 noted the magnitude of the drought-induced loss and determined that given all classes "participated" in developing the loss through energy consumption, all customer classes should share in funding it through across-the-board rate increases;

- While the COSS appears to be arithmetically sound, the model involves a number of judgmental allocation and forecasting procedures requiring further testing and consideration. Each COSS involves considerable judgment; and with no industry standard available to guide the process, there is no "right" or "wrong" way to allocate costs. The fundamental objective in designing a COSS is to select a cost allocation method that both reflects cost causation and results in an equitable sharing of costs; and

- The Board was dissatisfied with the COSS design, as it evidenced by Orders 7/03, 101/04 and 143/04, and directed MH to file additional information and alternative COSS models, which are the subject of this Order.

MH filed COSS data with the 2004 GRA incorporating most of the Board directives from Board Order 7/03. However, a number of concerns remained, including.

- Former Winnipeg Hydro data had not been fully incorporated into the MH model, nor had an allocation been made of direct costs to the Area and Roadway Lighting customer class for the former Winnipeg Hydro territory. The RCC for the Area and Roadway Lighting class, being significantly outside the higher limit of the ZOR, was also a topic of discussion at the May and June 2006 hearing;

- COSS methodology did not include an Export Class, a situation raised in Board Order 7/03 and addressed more definitively by Orders 101/04 and 143/04;

- The cost of the legislated uniform rate policy (the former three-zone rate schedule for grid customers was collapsed into one rate zone, resulting in reduced rates for customers in rate zones two and three) had been allocated to the residential class rather than being deducted from net export revenue; and

- Extraordinary circumstances were present in that a major drought had occurred.

With rising export unit prices and revenue over the last decade there has been increasing support for creating an export class for COSS modeling purposes.

Commenting on the COSS submitted with MH's 2004 GRA, Board Order 101/04 anticipated that upon an export class being established and other desirable amendments to the COSS model RCC indices for some classes would change materially. The Board therefore considered the COSS to be "in a state of flux."

In the 2004 hearing, MH filed the NERA report entitled "Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies". NERA's report provided several recommendations, most notably that:

1. generation costs should be allocated on the basis of time differentiated marginal costs;
2. the classification of transmission costs should be on a line specific basis;
3. costs and revenues pertaining to exports should be allocated to an export class; and
4. net export revenue should be allocated to domestic customer classes based on total costs, not just generation and transmission costs.

Although NERA initially proposed a single export class, during the May and June 2006 hearing, MH produced evidence that NERA was willing to support MH's two export class recommendation. NERA also recommended allocation of full costs against the export class. As with domestic sales, costs associated with export activities include generation, transmission, operating, maintenance, finance and administrative costs, water rentals, energy purchaser, capital taxes, and, treated as a cost for COSS purposes, the provision for net income.

Net revenue arising out of export activities is allocated to the domestic customer classes in the COSS, and has benefited Manitoba-based customer class rates. Overall, in recent years, domestic customer rates are "below cost" because of the sharing in the benefits of MH's export sales experience.

Contrary to its position at the MH Status Update 2002 hearing before the Board, MH supported the addition of an export class to the COSS at the 2004 GRA hearing, as did a number of interveners. The Board concurred, having favoured the establishment of an export class from Order 101/02. In Order 101/02 the Board concluded that without an export class and in the absence of a reasonable method of allocating costs to arrive at net export revenue, and its subsequent distribution to domestic customer classes, COSS and related class RCCs were suspect. Historically, in arriving at the net export revenue allocated to domestic customer classes for COSS purposes, only a share of MH's provincial water rental assessments and the cost of imported power were allocated against export revenue. No allocation for a share of generation, transmission, operating and other costs other than water rentals and imported power costs, were made. In the Board's view, this resulted in overstated net export revenue credited back to the domestic classes in the COSS.

At the 2004 GRA hearing, RCM/TREE opined that:

- the allocation of generation and transmission costs should reflect the assignment of higher cost newer vintage generation and transmission assets to the export class; and

- marginal costs rather than embedded costs should be allocated to all classes, including a new export class.

On November 1, 2005, MH filed a 2006/07 and 2007/08 GRA seeking approval of rate schedules incorporating average increases in domestic customer rates of 2.5% effective April 1, 2006 and a further 2.5% effective April 1, 2007. Materials filed by MH in support of the GRA, which was later withdrawn, included the four COSS versions (PCOSS-06) in response to directives in Order 101/04.

PCOSS-06, based on MH's preferred methodology, is an embedded cost study. Unit costs represent the average costs incurred to serve customer classes based on forecast costs for the fiscal year ended March 31, 2006. PCOSS-06 was drawn from MH's IFF 01-04, extending from fiscal 2004/05 through to 2014/15. The forecast was prepared in October 2004 and is adjusted for COSS purposes.

MH's preferred model modified the NERA recommended one export class method by proposing two export classes, firm and opportunity. MH proposed directly assigning only variable costs to the Opportunity Export Class, and made no direct cost assignments to the Firm Export Class, only allocations consistent with the approach taken to the domestic customer classes.

PCOSS-06 differed in two other aspects from the approach recommended by NERA in 2004. A first charge was made against net export revenue to fund the legislated uniform rate policy (estimated cost, $16.8 million), as directed by the Board in Order 101/04. In addition, the source data used to calculate marginal cost of generation was the inflation adjusted Surplus Energy Program information for the period January 1, 1999 to October 4, 2005, rather than the commercially available Platt's data (general industry pricing information) used in PCOSS-04

The weight given to the COSS in the overall rate setting process depends in large part on the soundness of the model and the general support of the parties to the process. A well-designed COSS is an important mechanism assisting in the development of rate applications. However, even a properly designed, regularly applied and publicly supported COSS is not the only factor to be taken into account by the Board in approving rates. *Significance of Net Export Revenue in Rate Setting*

Leaving COSS techniques aside, the broader context has MH employing COSS in developing its domestic rate proposals. Revenues are to be sufficient to meet costs and, over time, build sufficient retained earnings to provide an adequate reserve commensurate with the utility's diverse risks. To date, rate setting for Manitoba customer classes has not considered wholesale bulk export prices, which can serve as a proxy for the marginal cost of production in that power not sold to Manitoba customers, may be sold on the export market at market rates.

Because of the low cost hydro generation that resulted from Lake Winnipeg Regulation, Churchill River Diversion, particularly the three Lower Nelson River Generating Stations and the High Voltage Direct Current Transmission, MH has been able to average about 20,000 GW.h of exports over the last 15 years. Generation facilities built during the 1970s and 1980s has provided MH with low-cost energy at delivered costs below 3¢/kW.h that it has sold at progressively higher export prices (increasing from 1.5¢/kW.h in the early 1990s). The benefits received from MH's export revenues have allowed domestic customer rates to remain below the North American and Canadian average.

MH has experienced favourable flow conditions (average or above) for hydraulic generation in four of the last five years; nine of the last ten years; and thirteen of the last fifteen years. Since the Limestone generating station came into service in 1990, MH has only experienced two severe drought years, and has consequently been able to sell substantial energy to the export market on an almost continuous basis.

Ninety years of flow history provides a good perspective on the potential for significant drought events. Variable degrees of drought events have happened in about 20% of the years, with severe droughts having occurred in approximately 10% of the years. Extended severe droughts (those extending two years or more) have occurred at least three times. The 2003-04 drought had severe financial implications on MH.

Without substantial export sales, there would be no net export revenue to benefit domestic customer classes through below-market rate levels. In the absence of export profits, the annual revenue requirement would have to account for domestic costs and ensure adequate retained earnings. Without substantial net export revenues to be allocated to domestic customer classes, a fair rate setting approach for the various customer classes would be easier to design, though rates would be higher.

Exports made possible by excess generation and transmission capacity, and transmission links to the United States and neighbouring provinces, provide the potential for revenues exceeding costs by a significant degree. It is MH policy and practice to make investments in generation and transmission with exports in mind. Generation additions may be advanced and capital and operating expenditures incurred to make the most of the export potential. At this hearing, MH advanced the view that:

- export revenues, driven by increased unit prices that have increased from under 1.5¢/kW.h to above 5.5¢/kW.h over the past ten years, rather than volumes (export volume is affected by increases in domestic consumption as well as available annual water flows), require reconsideration of the current approach to allocating net export revenue to the domestic customer classes; and

- rather than adding one export class to COSS, as originally recommended by NERA, MH suggested there be two export classes, one with respect to firm sales, the other for opportunity sales, and somewhat different costs should be assigned to each class to arrive at net export revenue.

MH questioned the established practice of allocating net export revenues to the various customer classes in proportion to each class allocated share of generation and transmission costs only. With 2005/06's export revenue reportedly approaching domestic electricity revenue, MH suggested that allocating net export revenue to the customer classes based only on generation and transmission costs would unduly benefit certain customer classes and be unfair to other classes.

MH held that the current practice of allocating net export revenue on the basis of generation and transmission costs only would produce RCC indices suggesting a further reduction in already low industrial rates. For both fairness and energy efficiency reasons, MH proposed making the allocation of net export revenue to the domestic customer classes on the basis of total allocated costs.

COSS Links to Financial Forecasts

A revised COSS, whether in accordance with MH recommendations or not, will remain linked to MH's financial forecasts and annual revenue requirement and account for projections of net export revenue. The determination of the aggregate revenue requirement from Manitoba customer classes will rest in part on decisions with respect to the amount of overall net income required, after having provided for all costs and having taken into account net export revenue.

With the notable exception of drought years, MH anticipates that annual net export revenue (after deducting full costs) will exceed overall net income, and net export revenue will be sufficient to support the continuation of domestic rates below both full historic cost recovery and market rates.

Utilization of Net Export Revenue

If the allocation of net export revenue to domestic customer classes in the COSS model was reduced below the forecast level and the difference allocated to a purpose other than to support domestic class rates, this would change the RCC indices for each class and could result in higher domestic rates. Various kinds of potential deductions from net export revenue prior to the allocation of net export revenue to the domestic customer classes within COSS were discussed at previous hearings and again at the May and June 2006 hearing. The potential list includes:

- to meet the cost of the legislated uniform rate policy , as directed by Orders 101/04 and 143/04;

- to increase the level of retained earnings, as suggested by MIPUG;

- to pay a dividend to the Province. This has occurred previously pursuant to legislative sanction; subsequently, the Board, in Order 101/04, suggested no further dividends be considered until MH's debt:equity ratio reaches the 75:25 debt:equity target (dividends require cash transfers and result in increased debt and interest costs);

- to fund energy efficiency measures, raised as an option at this hearing and a feature of the recent Bill 11 legislation;

- to provide a subsidy to the diesel customers;

- to assist in funding various provincial health, welfare or social costs; and/or

- for direct payment to Manitobans, apart from rate reductions.

Interveners held that proposals to distribute MH's net income other than in either the form of reduced rates or to build retained earnings were outside of the jurisdiction of the Board and contrary to the intent of MH's legislation. CAC/MSOS and MIPUG held that current legislation does not provide for any other disposition of MH earnings other than to bring about rate reductions or increase retained earnings.

Manitoba Hydro's Financial Position and Risks

With respect to the option to increase the level of MH's retained earnings, Board Orders 101/04 and 143/04 expressed the Board's concern with MH's then-current debt:equity ratio and provided support for its target debt:equity ratio of 75:25. At previous hearings, and as reflected and elaborated on in Board Order 143/04, MH's environment includes a host of material risks, one of the major risks being a sustained drought.

According to MH, a five-year drought could result in the utility experiencing a loss in the range of $2.2 billion, approximately twice MH's current retained earnings. Furthermore, there is an expectation of severe weather fluctuation associated with climate change, which could include more frequent droughts than has been the case. To date, MH has not provided a detailed calculation quantifying the specific components of drought risk. The Board looks forward to reviewing MH's detailed quantification based on the current forecast model, one that takes into account the expectation of shortfall pricing during periods of energy supply deficiencies.

Leaving aside droughts, other known risks include:

- the Canadian dollar, which has increased by 50% relative to the American dollar over the last four years. MH holds that its exchange risks are adequately hedged by sales in American dollars. The escalation of the Canadian dollar amounts to a 30% reduction in the relative cost of US energy production (other than natural gas) and may make conventional coal generation more attractive from an American utility's bottom line perspective;

- increased interest rates affecting financing costs for significant new generation, transmission, distribution and office building expenditures, which are planned to be largely funded by additional debt. As well, existing debt will mature and require refinancing, perhaps at higher rates. Although current Canadian short and long-term interest rates are currently low, there has been recent upward pressure;

- major infrastructure failure that may bring about the loss of export and domestic sales and the incurring of supply and repair costs. MH largely self-insures for property damage and liability with respect to catastrophes;

- market disruption, reported to be capable to producing losses in excess of the worst-case drought loss estimate of $2.2 billion. A limited degree of this risk may already be in process with the recent more favourable perception of conventional coal generation and reduced commitments to Kyoto targets; and

- a decline in the average unit export price, perhaps due to weather or increased American reliance on relatively low cost coal combined with uncertain natural gas prices. Export prices are priced at the marginal cost of production for the American utilities, which may be constrained by a return to reliance on coal-fired generation.

The risk of an export price decline in real after-inflation terms arises as a result of American electricity utilities' concern with the risk of future natural gas price bubbles, such as occurred last winter. In response, it would appear that American utilities may increasingly rely on coal, and not necessarily the higher priced so-called "clean coal" version, for generation feedstock. Coal is attractive for MH's export market customers because of plentiful supplies, close proximity of supply to new generation and, relative to natural gas, stable pricing. Coincidentally, MH continues to exploit its coal-fired generation for export purposes, with its Brandon coal plant not scheduled to close in the near future.

Since the natural gas price bubble of the winter of 2005/06, natural gas prices have plummeted, driving down the marginal cost of peak electricity generation in the United States and affecting MH's recent opportunity export sales pricing. While the natural gas price decline may be temporary, it illustrates a risk difficult to quantify, that being that the marginal cost of production for American utilities, and hence MH's export prices, may not increase as forecast by MH.

Parties to the Board's MH hearings have generally accepted that MH's retained earnings should be sufficient to avoid the necessity of a large above-inflation rate-increase in the event of a major setback such as a drought or the realization of one or more of the other major risks. Past regulatory practice has defined rate shock as a rate increase of 10% or more implemented within one year. Though MH has not built into its forecasts the full potential effect of a severe drought, it has forecast a need for annual 2.5% rate increases. The projected increases are representative of the expected level of annual price inflation. MH's objective is to bring its debt:equity ratio to the target of 75:25 within ten-years.

As MH increases its investment in plant and equipment at ever increasing incremental cost, and its reliance on net export revenue continues to expand, the utility's risk profile increases bringing into question whether the existing debt:equity target is achievable, let alone adequate.

This question of the adequacy of MH's retained earnings is underscored by a review of the "firmness" of MH's retained earnings. In Order 143/04, the Board noted that MH has a relatively higher level of deferred costs carried as assets compared to B.C. Hydro and Hydro-Quebec. As well, there is the matter of MH's investment in thermal natural gas generation plants, rarely operated and uneconomic at current natural gas prices.

As well and as previously noted, MH's net income forecasts are dependent on export sales, net export revenue and the continuation of favourable water levels as experienced in the past. In the absence of large net export revenues, which could fall for one of a number of reasons, domestic rates would need to rise by more than MH's current forecast of annual 2.5% rate increases if the 75:25 debt:equity target is to be achieved within the next ten years.

This question of the adequacy of MH's retained earnings target is further highlighted by evidence indicating that both B.C. Hydro and Hydro-Quebec have arguably "stronger" balance sheets than MH, with equity balances higher on both an absolute and percentage basis. These other electricity-based Crown Corporations have higher equity components despite the fact that both pay annual dividends to their provincial governments.

On the other hand, evidence presented at the 2006 hearing suggested that neither B.C. Hydro nor Hydro-Quebec credits back to their domestic customers a share of their annual net export revenue. The significance of MH's net export revenues to COSS and domestic rates depend in large part on the amount of net export revenues credited back to the domestic classes, rather than being employed in some other way. This topic will be revisited at the next GRA hearing, and may be important to future rate decisions.

In advance of this discussion, in this Order the Board provides MH direction that it should consider future domestic rate increases greater than the 2.5% annual increases reflected in its most recent IFF, in an effort to expedite reaching the debt:equity target.

Key Issues and Questions of the Hearing

At the end of the day, the Board considered the four key issues and questions to have been:

1. Should there be one export customer class (as initially proposed by NERA), two export customer classes (as recommended by MH) or some other number of export customer classes?

2. What costs should be directly or indirectly assigned or allocated to the export class or classes?

3. How should any resulting net export revenue benefit be credited or allocated to the domestic customer classes? and

4. To what degree should the COSS resulting from the Board's determinations arising out of the hearing process drive future rate decisions?

Although these four issues received the greatest attention through the hearing, and have the potential to have the greatest affect on the COSS results in future GRA proceedings, there were a number of other issues that were examined, including:

1. whether embedded costs, marginal costs, or both, should underlie COSS;.

   The Board concludes that the COSS should continue to be prepared using embedded costs. However, high level marginal cost and notional environmental cost information should be provided to supplement the COSS filing.

2. MH's use of SEP rates as a proxy for marginal costs;

   The Board accepts SEP rates as a proxy for marginal costs as recommended by MH.

3. the relevance, if any, of replacement cost and inflation adjusted cost in COSS development;

   The Board agrees with MH and the interveners that neither replacement cost nor inflation adjusted cost estimates are to be represented in future COSS. That said, the Board recognizes that the replacement costs of MH's assets may well be two or more times the depreciated costs carried on the utility's books and reflected in customer rates.

4. the appropriateness of the current functionalization, classification and allocation of costs, and consideration of alternative approaches;

   The Board directs certain amendments to MH's recommended methodology as set out below.

5. identification of the key differences between the results provided by various COSS methodologies, such as between NERA's proposed COSS, the generation vintaging

method proposed by RCM/TREE, the current methodology, and MH's recommended method;

A key difference between the methodologies is the treatment of the export customer class. The Board will direct that there be one export class, with modifications to the initial NERA recommended model.

6. the deferral of MH's planning costs, DSM and other costs, and the impact to be anticipated with a different approach for regulatory purposes than that taken for MH's financial statements;

The Board remains concerned with MH's cost deferral approach, and takes the view that it negatively affects the "value" of MH's statement and forecasts of debt:equity ratios and retained earnings. The Board intends to review the matter further at the next GRA hearing.

7. the accounting and COSS treatment of mitigation costs;

The Board has concerns similar to those held with respect to planning and other cost deferrals, and will review this matter at the next GRA.

8. regulatory accounting options with respect to the treatment and/or allocation of costs related to MH's thermal plants;

At the next GRA hearing, the Board will review the merits of establishing a regulatory accounting methodology different from MH's external financial reporting, and will consider regulatory retained earnings to reflect various deductions not reflected in the financial statements.

9. the impact of Bill 11 and the uniform rate policy on COSS;

Transfers of MH's net income to a Fund pursuant to the Winter Heating Cost Control Act (Bill 11), and the cost of the uniform rate policy, are to be allocated against export revenue in future COSS.

10. allocation approaches with respect to water rental, fuel and power purchases;

The Board will direct that MH allocate water rental costs to the new export class in the same manner as is done for the domestic classes. Fuel and imported power purchases should be assigned directly against export revenue.

11. class consolidation options and consideration of appropriate rate differentials for various sub-classes;

The Board will direct MH to file reports providing proposals with respect to class consolidation and justification for rate differentials.

12. issues related to MH's capital investments for export purposes: past, present and planned, in light of MH's overbuilding of hydraulic stations beyond dependable domestic energy load requirement;

The Board concludes that MH invests in capital plant and equipment for export purposes through advancing in-service dates and installing additional generation units, etc.

13. possible adjustment of demand and energy charges within the rate schedules to promote energy conservation;

The Board will direct MH to file proposals to end declining rate blocks, rebalance demand and energy charges and implement inverted rates for industrial customers and other large energy users.

14. time of use rates particularly as they relate to marginal costs;

The Board will direct MH to file proposals for the appropriate implementations of Time of Use Rates for non- residential customers, including the possible elimination of the "winter ratchet."

15. terms and conditions of export contracts, which affect the relation and availability of firm and opportunity sales;

The Board concludes that both firm and opportunity export contracts are important to MH's results, and similar enough in nature to justify only one export class.

16. the allocation to customer classes of costs related to purchased power, including wind and Wuskwatim, not expected to be required to meet domestic load out ten to twenty years;

The Board accepts MH's proposal that wind generation purchases be assigned to the export customer class, and that Wuskwatim's costs be treated as are other hydroelectric generation costs.

17. the treatment of HVDC transmission losses affecting the cost allocation process within the context of fully assigning embedded costs to all exports, for across-the-board average allocation of transmission losses rather than incremental;

The Board accepts MH's proposed treatment.

18. MH's power resource plan which provides for dependable energy to serve domestic load, as well as energy surpluses in average annual energy; and

The Board will require MH to file an updated power resource plan indicating among other matters the proposed role of Wind and the Wuskwatim Generating Station; and depicting the potential roles of other proposed generating stations.

19. Treatment of CO_2 and Other Global Warming Issues which may need special consideration in the determination of appropriate domestic rates.

The Board will review future rate designs in a context that reflects favourably on actions to reduce CO_2 and other noxious gases on both a Manitoba and a global basis.

Low Cost Based Electricity Rates

Electricity is a vital supply in today's world, and Manitoba's economy relies on secure, adequate and affordable power. Industry has located in Manitoba and expanded with "low cost based" electricity as one of the factors in the decision, a primary factor for some. Some would hold that changes to the COSS, as directed herein, will lead to higher electricity rates for new large energy consuming industry compared to other customers, and that such a development would be unfair, risking Manitoba's industrial base.

Others may fear that COSS changes will lead to general rate increases for current domestic customers, and some of these observers may rank affordability as a higher priority than other objectives, such as recognizing environmental issues, the importance of energy efficiency and/or the strengthening of MH's capital base. The Board will continue to examine these issues.

Recent Events

Significant changes have taken place in MH's environment since the current embedded cost version of COSS was implemented. Over the last 10 to 15 years these changes included:

a) the acquisition of Winnipeg Hydro, which brought MH new revenues, costs, assets, liabilities and borrowings, along with increased responsibilities, opportunities, risks and challenges;

b) a three-fold increase in average unit export price between 1996 and 2006, driven in large part by increased commodity prices (most relevant, natural gas and coal), leading to higher input costs for American non-hydro generation. Higher marginal generation costs for American non-hydro generation improved the prospects for MH's electricity export prices;

c) changes in the structure and nature of the export market, brought about mainly through the development of the MAPP/MISO trading market and Ontario's growing energy requirements (MH can export excess generation at the marginal costs of American utilities, as defined by MISO rules, limited only by transmission capacity and economic considerations);

d) for the first time in MH's history, in fiscal 2005/06 export revenues approached domestic electricity revenues with the export price per kW.h exceeding, also for the first time, the average price for domestic electricity;.

e) Increased recognition that higher domestic consumption with rates below average unit export prices translates into lower aggregate MH revenues and annual net income;

f) increased recognition of the value of energy efficiency measures, which reduce domestic consumption and provide for increased export sales. Effective demand side management (DSM) is profitable for MH when the present value associated with the marginal benefit of export sales over domestic sales exceeds the net costs of implementing DSM;

g) environmental concerns are now “front and center”, not only with the public and in the media but also as a focus of government attention. Manitoba enacted the SDA, Canada signed the Kyoto pact (although the latter’s status is presently uncertain with respect to the federal government’s intentions, Manitoba remains committed to addressing the causes and deleterious affects of climate change);

h) the advent of emissions trading, very active in Europe though fledgling in North America;

i) MKO’s developing view, not shared by MH , that “communities located on the waterways directly impacted by MH” are entitled to a greater share in net export earnings and should not be assessed any share of mitigation costs incurred by MH;

j) increased loss projections for sustained droughts, demonstrating the importance of MH’s export relationships (low water flow year losses may exceed gains in high water flow years – in short, the “worst” scenario overwhelms the “best” when drought and high water flows are compared);

k) planned major new generation and transmission: 99 MW of wind generation has been installed, Wuskwatim has received First Nation approval, and other generation plans are on the drawing board. These projects, which in total involve billions of dollars of additional debt, will impact MH’s risk profile and debt:equity ratio, while also increasing generation and transmission capacity with positive expectations for future export revenue;

l) despite significantly improved average and high net income years experienced over the last 15 years with very favourable water supply conditions, MH's debt:equity ratio remains below the Board-approved target of 75:25 and is forecast to improve only slowly over the next decade – the projected improvement is vulnerable to further deterioration under a number of risk realization scenarios (export market prices fall, rate increases are not implemented, drought, etc.); and

m) the identification of a risk associated with large energy-dependent multi-national firms with high-energy use/low employment ratios seeking out jurisdictions with low electricity rates, Manitoba reportedly being the lowest electricity rate jurisdiction in North America. MH has expressed a concern that such new or expanded high-energy dependent industries will lead to rate increases, or, in the absence of higher rates, lower aggregate revenues and net income and a higher debt:equity ratio (through the displacement of export sales at higher rates and possible new generation requirements for industry paying lower rates). MH reinforced these concerns related to energy-intensive industry using electricity as feedstock, by reporting that large firms using considerable electricity have increased their aggregate electricity consumption from 564 GW to 1,661 GW over the past five years. These concerns may be mitigated if the additional use is concentrated in the off-peak periods. (Quebec limits assured energy supply for energy-intensive firms, requiring special consideration of appropriate rates for such firms.)

Last Rate Increase and Forecasts

The last MH rate application was heard in the summer of 2004 following the end of the 2003/04 drought, and led to Board-directed rate increases and other directives, including a requirement for further research into COSS methodologies.

The rate directives included a 5% firm across-the-board rate increase, two 2.25% conditional rate increases, and provision for further research into inverted rates; MH did not pursue the second of the conditional rate increases, citing record net income forecasts for 2005/06. In anticipation of the 2006 annual report, which has yet to be released, MH advised the Board that its net income for 2005/06 exceeded $375 million, and was the highest net income recorded in MH's history.

MH forecasts annual rate increases of 2.5% per year, continuing a perspective that has been advanced in MH's prior IFF documents. Yet, the rate increases projected in succeeding IFF documents over the past ten years were generally not sought or implemented, as net export revenues increased due to a succession of years of favourable water levels and export prices. While leaving rates unchanged year after year until 2004 has resulted in low electricity rates for domestic customers, it has also resulted in an inadequate capital base for a utility facing increased risks.

The following major events since the summer of 2004 bear on MH's future prospects:

a) the relationship between energy commodity prices and export prices was illustrated and confirmed through the market experiences following Hurricane Katrina and Rita, last summer and fall. The hurricanes damaged and disrupted Gulf of Mexico gas production and transportation, and led to a spike in natural gas prices (the price per gigajoule (GJ) doubled), and this was followed by corresponding sharp increases in wholesale bulk export sale prices bringing about record MH net income, estimated by MH at $375 million for 2005/06;

b) following record high winter temperatures and the recovery of natural gas production and transportation in the Gulf, natural gas spot prices fell to near 2003 levels, leading to a corresponding fall in wholesale electricity prices and MH's SEP prices, leading to the risk of a decline in net income from 2005/06's anticipated record levels in 2006/07 (some market observers expect current low natural gas prices to rebound in the winter months, and this would move up SEP bulk electricity prices which have recently been off from average 2005/06 prices);

c) the original version of Bill 11, recently approved in amended form by the Legislature, initially recognized the interplay between natural gas and electricity and allowed MH some capacity to spend electricity-based revenues on gas DSM (high net income of MH for fiscal 2005/06 relates in part to high natural gas prices through to January 2006, which drove up electricity export prices); the amended bill as enacted restricts the cross-energy commodity related expenditure to filling in for the recently cancelled federal share of gas DSM. Through past Board Orders related to Centra Gas, a MH subsidiary, MH was directed to integrate its gas and electricity DSM plans, and provide increased attention to the situation of low-income customers unable to fund energy efficiency measures;

d) a 99 MW wind farm was constructed at St. Leon, and MH's IFF was amended to reflect 250 MW over ten years (the government's expressed goal is 1,000 MW). While wind generation is apparently of marginal economic value to MH, it does at some level contribute to environmental progress and rural development;

e) capital cost estimates for MH's major projects have increased sharply. Wuskwatim's estimated capital costs have increased from CEC hearing estimates, and the projected costs of MH's new downtown head office has reached $360 million by the most recent estimate;

f) interest rates have increased somewhat, since falling to 25-year lows, but remain low, while the Canadian dollar has risen from 63¢ to a recent range of 87 cents to 90¢;

g) a tentative settlement with Indian and Northern Affairs Canada (INAC) was negotiated by MH with respect to the electricity service and costs for four northern First Nation communities served by diesel; the settlement involves payments to MH by INAC in excess of $20 million, and assumes MH's diesel class customers will receive future benefits from MH's net export revenue;

h) the provisional diesel settlement with INAC remains to be concluded, yet diesel fuel prices have risen sharply making current diesel rates inadequate with respect to deficit-prevention;

i) the provisional new power sale to Ontario of 400 MW presumes a displacement of coal generation in Northwestern Ontario. However, Ontario is reconsidering coal generation and has expressed interest in new nuclear generation;

j) MAPP/MISO's new trading arrangements came into place, providing MH marginal cost pricing on opportunity exports and the ability to meet American export contracts with purchased American power (allowing the diversion of MH generation to Ontario at positive margin). While arbitrage activities were reported to have provided gross export revenues of $160 million in 2005/06, there is no guarantee MH will always achieve materially positive results from arbitrage.

Forecast of Future Rate Increases

MH confirmed its most recent IFF projection that 2.5% overall domestic annual rate increases will be required and sought through to the end of the forecast period, notwithstanding anticipated good export markets. MH's forecasts, plans for new generation and transmission, and the current state of the debt:equity ratio, support MH's projection of a need for annual rate increases at least at the rate of inflation. It also supports appropriate pricing for new large energy intensive industrial customers – this to avoid net income declines through substitution of low domestic industry prices for assumed higher export prices.

Any revised COSS design should be conceptually sound and robust enough to respond to changing circumstances for some time into the future. Although fine-tuning may be expected, it would be practical and desirable for the new model to be designed to accommodate expected future developments.

Manitoba Hydro's Importance to Manitoba

MH, Manitoba's largest and oldest provincial Crown Corporation, is an integrated energy company providing electricity and natural gas to approximately 500,000 all-electric customers and 250,000 electricity and natural gas customers (through its subsidiary, Centra Gas Manitoba Inc.). MH's consolidated annual revenue approaches $2 billion, with the majority provided by Manitoba's residential, commercial and industrial electricity customers. MH's assets approach $10 billion, and the Corporation is one of Manitoba's largest employers with a personnel complement approaching 6,000 employees.

The Corporation operates fourteen hydroelectric, two thermal and four remote diesel generating stations, purchases 99 MW of wind generation, and has plans for additional hydroelectric and wind generation and transmission assets. In recent years, MH acquired Centra Gas Manitoba

Inc. and Winnipeg Hydro, and integrated these operations with those of its pre-existing electric operations. The Corporation is also involved in and, from a financial and operating perspective benefits from, the export and import of power, primarily to and from the United States.

MH is administered through a Board of Directors appointed by the Lieutenant Governor-in-Council, and is funded not only by revenue from electricity and natural gas sales but also from borrowings guaranteed by the Province and intended to enhance future profitability. These borrowings, which the Corporation services from operating income, enable the Corporation to develop generating, transmission, distribution and administrative capacity and services. MH's generation and transmission capacity is required to provide reliable service to the Corporation's Manitoba customers, as well as to take advantage of export opportunities as surplus capacity allows.

Because MH is a capital intensive utility, many of its costs derive from the amortization and financing of plant costs with medium to long term service horizons. This is the case both with respect to electric and natural gas operations.

Consistent with the importance of MH to Manitoba, the Corporation's debt represents more than half of the Province's overall borrowings. MH is subject to the direction and/or oversight of the legislature, the Government of Manitoba, its Board of Directors, Crown Corporations Council, the Public Utilities Board and, with respect to the Wuskwatim and other future generation projects, the Clean Environment Commission. Two members of the Public Utilities Board sat on the Clean Environment Commission during its hearing on the proposed Wuskwatim generating station and transmission project.

MH's annual revenue requirement and rates are subject to the approval of the Public Utilities Board. With respect to its electricity operations, MH has a significant involvement in and reliance on export energy sales, with all classes of Manitoba consumers' rates benefiting from actual and expected export profitability. MH prices its electrical sales to Manitoba customers using as a tool a COSS methodology based on cost, which is not representative of either marginal cost or the market value for energy in North America.

Closing Comments on Context

By this Order, the Board answers and/or addresses key questions and issues, while providing views and direction on and with respect to other issues of interest. As previously indicated, the transcript of the hearing may be accessed at www.pub.gov.mb.ca, providing not only more detailed information on the interests and positions of the participating parties, but considerable additional information on the operations and prospects of MH.

3.0 Intervener Positions

As previously indicated, the full positions and views of the Interveners, together with the evidence heard by the Board from witnesses brought forward by MH and the Interveners can be accessed either at the Board's office or through the Board's website, www.pub.gov.mb.ca. This reportage of intervener positions focuses on major issues, and omits some of recommendations and positions put forward by interveners, though all were considered by the Board.

No intervener denied MH's assertion that a fundamental change had occurred in MH's situation and environment, and that the change related to the increased unit sales price of exports. All parties accepted that with the advent of the new MAPP/MISO trading rules and arbitrage opportunities, export revenue has increased dramatically improving MH's annual net income prospects and providing increased support to low domestic rates. MKO noted when the northern generation plants were constructed the rationale provided to First Nations by MH and government was that the facilities were required for Manitoba electricity needs, not for export.

All interveners supported the addition of a new export class to the COSS model, though support differed with respect to there being two export classes as recommended by MH. Other major issues addressed by interveners included:

- MH's concern with respect to energy demand and consumption of energy intensive industry, and its initial indication of interest in appropriate pricing for industry;
- energy efficiency and effective price signals;
- marginal costs and carbon emissions as factors to be considered in COSS and rate setting;
- continuation of COSS based on historic embedded costs,
- rate setting factors, the relationship between COSS and rates;
- the allocation of net export revenue to domestic customer classes to reduce and restrain domestic rates;
- the basis for the allocation of net export revenue to domestic customer classes, including generation and transmission costs only, or total costs;
- concept of "excess" net export revenue with respect to COSS;
- use of MH Net Income for other purposes other than rate restraint and retained earnings development; and
- MH's financial position and forecasts.

Several interveners expressed the view that the inputs to the COSS should be limited to MH's projected embedded costs and revenues, and that the RCC ratios that result from the COSS for each customer class should be brought within the ZOR over a reasonable period of time.

CAC/MSOS supported MH's proposal for two export classes, distinguishing, as did MH, between "opportunity" and "firm" export sales. CAC/MSOS also supported MH's proposal that only variable costs be assigned against the opportunity export class. MIPUG indicated a slight preference for only one export class, but was prepared to accept MH's proposal for two export customer classes. RCM/TREE focused on a marginal and environmental cost based COSS model, favouring one export class.

MIPUG addressed directly MH's assertion that consumption by energy intensive industry was displacing available higher priced export sales, with industry rates being below export unit sales prices, reducing aggregate revenues and net income, risking rate increases for all domestic classes. Though no intervener contradicted MH's assertion that domestic consumption reduces export sales, and, in some cases, reduces aggregate revenue, MIPUG defended industrial energy consumption as being consistent with the vitality and economic health of the Province. MIPUG opposed MH's interest in surcharging industrial accounts, as well as any consideration of restricting supply, whether through pricing or by other means.

MIPUG asserted the benefits of industry, in the form of employment and taxes, and indicated that energy intensive industry located and expanded in Manitoba on the assumption of low electricity prices. MIPUG noted, and was notably not contradicted by MH, that the Province had marketed Manitoba as a site for industry using in part the advantage available through low electricity prices. Contrarily, RCM/TREE supported MH's concern, and suggested that industrial electricity prices in Manitoba were so low that it might attract a high energy consumption firm with few employees, and that such a situation would not be in the public interest. No evidence was presented on this or the alternative scenario that new industry could employ off-peak energy to the benefit of MH customers.

MIPUG opposed what it described as discriminatory practices, i.e. higher rates for new industry or expanded industry, and argued for the retention of cost based rates, again based on historical embedded costs. CAC/MSOS acknowledged MH's concern that higher industrial consumption could lead in time to higher rates for domestic customers, but offered no opinion in advance of a GRA, when rate proposals would be reviewed.

CAC/MSOS and the other interveners with the exception of MIPUG and RCM/TREE supported MH's recommendation that net export revenue be allocated to the domestic classes using all costs as the denominator rather than only generation and transmission costs (G&T). For CAC/MSOS and RCM/TREE continuation of the approach of using only generation and transmission costs would send the wrong message about cost causation and be unfair. MIPUG disagreed and argued for the retention of an allocation of net export revenue based on generation and transmission, as being the approach most consistent with cost causation. No evidence was presented relative to the lower export revenue sensitivity of generation, transportation and distribution expenditures (G&T&D) as compared to utilizing only G&T expenses in the allocation process.

MIPUG responded to MH's assertion that net export revenue had reached a level that made crediting of it back to domestic classes within COSS untenable when the allocation distribution was based only on generation and transmission costs, by proposing a net export revenue threshold be established.

MIPUG proposed that a threshold be established representing a level of net export revenue deemed too high for crediting back to the classes. The excess would be held to build retained earnings, with the threshold to be discussed and determined at the next GRA. MIPUG noted that if net export revenue slowed or declined, its proposal could mean higher rates for domestic customers, including those represented by MIPUG.

CAC/MSOS and RCM/TREE supported energy efficiency demand side management initiatives, with CAC/MSOS holding that the cumulative record has each dollar of DSM expenditure bringing about domestic energy consumption drops worth $2 to $5, thus allowing for additional exports. RCM/TREE noted that DSM reducing consumption in Manitoba allowed for increased exports to the United States, bringing about lower carbon emissions in the United States, as well reduced Manitoba customer bills.

MIPUG, CAC/MSOS and CCEP indicated an expectation of a close relationship between the results of COSS as measured by ZOR indices and actual class rates, a preference muted in part by the acceptance of all parties that COSS is only one component of rate setting.

All interveners indicated acceptance of the concept of gradualism, defined as the movement of class rates outside the ZOR to within the ZOR over a period of time to allow for rate stability and avoid rate shock.

As previously indicated, among interveners only RCM/TREE evidenced support for the utilization of marginal costs and a measure of environmental costs representative of carbon emissions as input factors in the preparation of COSS. RCM/TREE based its support for its witness' proposal that COSS take into account carbon emissions and marginal costs by noting:

a) MH can sell all its excess generation on the export market, subject to transmission and other restraints. Thus, domestic energy use reduces exports. As carbon emissions in MH's export markets would be reduced by increased exports of MH's "clean power", emissions caused by Manitoba energy consumption should be taken into account in COSS models;

b) exports of MH "clean" power displace natural gas/maybe coal generation in the United States, reducing continental carbon emissions;

c) MH's rates for some classes at times are below available unit export prices;

d) domestic consumption reduces export revenue and, when domestic rates are below unit export prices, reduce overall revenue and net income;

e) marginal costing if appropriately defined promotes efficiency and penalize undue energy consumption; and

f) the substitution of marginal costs for embedded costs within COSS would provide for a different and fairer view of each class' recovery of "total costs" (including opportunity losses with respect to potential export sales and carbon emissions).

RCM/TREE further supported the inclusion of marginal costs and accounting for emissions within COSS by citing the objectives of the SDA. RCM/TREE commented that both MH and the Board are obliged to further the SDA's goals (a position enunciated by the Board in Order 143/04.).

RCM/TREE witness' evidence with respect to climate change and emissions and the full cost accounting cost of externalities arising from electricity generation is supported in the broadest sense by scientific studies available in the public domain. As one "local" internationally-recognized source, the International Institute for Sustainable Development (IISD) July 2003 paper *The Full Cost of Thermal Power Production in Eastern Canada* concludes that electricity generation from coal and natural gas produce significant emissions of air pollutants and greenhouse gases. IISD's paper notes that such emissions are linked to human health, general environmental and economic damages.

The Board agrees with RCM/TREE that not all externalities are priced into the cost of generation and that, as claimed by IISD, "buyers of … electricity … pay less than its real cost, and are inclined to use more of it than they otherwise would. Wherever prices of goods and services do not reflect full costs, markets are distorted and society bears the burden of this loss of social welfare."

IISD's study priced the externalities associated with coal-fired electricity generation (coal being the primary energy source for MH's export customers) at $.0394/kW.h, and for natural gas generation $0.171/kW.h. While, as IISD noted in its paper, the Board is unaware of any studies modeling emission dispersion in western Canada, the Board accepts that continental air flow is not restrained by national or provincial borders and climate change affects the planet.

While CAC/MSOS shared RCM/TREE's interest in reducing emissions, CAC/MSOS was opposed to the use of "untested and imprecise" volumes and costs as presented in RCM/TREE's sample COSS. As well, CAC/MSOS noted that RCM/TREE's proposal was limited to carbon emissions, and suggested that there were other environmental factors that should be considered if externalities not now priced into costs were to play a role in COSS development.

CAC/MSOS and MIPUG were concerned that a COSS based on RCM/TREE's total cost concept would promote much higher rates for domestic consumers, while departing substantially from "cost based" rates, an approach that has restrained cost pressure on consumers (cost being defined as embedded costs). Cost based rates, supported by all Interveners excepting for RCM/TREE, has meant reliance on historic embedded costs, costs reconcilable to MH's IFFs and financial statements. Such cost based rates have meant low electricity rates and attendant financial advantages to MH's customers, advantages CAC/MSOS and MIPUG cited as being at risk if COSS models utilizing marginal cost and estimated values for emissions were considered.

In past hearings, and to some extent in the most recent hearing, Interveners supported MH's debt:equity target of 75:25 while indicating awareness and a level of concern that the target appears years away from being achieved, despite recent years of generally improved net export revenue and net income. All parties view MH's retained earnings, the equity component of its debt:equity ratio, as being held as a hedge against the risk of large losses requiring, in the absence of adequate retained earnings, a rate increase or increases representative of "rate shock" (previously defined as an increase in excess of 10% in a single year).

MIPUG was the only intervener to deal directly with this concern, and suggested that a portion of net export revenue be withheld from crediting to domestic customer classes through the COSS model to assist in the building of retained earnings. All parties noted that doing so would not increase MH's retained earnings unless reflected in rate increases, as COSS only supports rate setting and does not determine it.

Only RCM/TREE suggested that net export revenue be used for purposes other than restraining domestic rates or increasing MH's retained earnings. MH supported RCM/TREE's position indirectly, by stating that, with the cost of energy exports fully met by export revenue, there was no requirement that net export revenue be used to restrain rates.

RCM/TREE suggested that net export revenue could be used to promote other public objectives (such as health, education and welfare) or be returned to either MH's customers or Manitoba residents by direct payment. RCM/TREE held that net export revenue should not be returned to customers in the form of rates that provide a price signal not conducive to energy efficiency and conservation. In short, RCM/TREE opined that below-cost rates encourage wasteful energy consumption.

CAC/MSOS opined that the legislation governing MH does not "contemplate" MH recording a profit "over and above all costs", though the intervener accepted the need for retained earnings to serve as a reserve against the actualization of a major risk. MH, supported by RCM/TREE, suggested that the current legislation "contemplates that MH's revenues will exceed its expenses for purposes beyond normal operating expenses, interest and other charges." MH also noted that its legislation allows for funds "not immediately required for corporate purposes" to be retained as a reserve. It is the Board's understanding that all parties accepted the premise that for MH to produce profits for purposes other than retention within retained earnings would require legislation. In Order 143/04, the Board took no position on dividends to the Province, though it discouraged the practice until such time as the debt:equity target has been achieved.

City of Winnipeg

The interventions of the City of Winnipeg were focused on the interests of the classes they represented. The City of Winnipeg held that the RCC of the street lighting class had been consistently outside the ZOR, and that an adjustment of that class rate downward should occur at the first available opportunity. The City also cited MH's customer service cost allocation methodology, and challenged its fairness.

CCEP

CCEP noted that its two classes of particular interest, small and medium general service, had long-standing RCC indices above the ZOR, and suggested that fairness required rate reductions to bring these classes within the ZOR.

MKO

MKO advised that rate design changes should take place concurrent with a new COSS model. MKO sought the removal of mitigation costs from the aggregate costs allocated to northern customers though the means of a 4% reduction in rates. The basis for the reduction would be that those customers should not incur any electricity charge related to mitigation costs.

MKO also favoured the creation of a new class for Hydro-affected customers residing on the waterways utilized by MH, a class to receive a specific sharing of net export revenue based on recognition of a fundamental change having occurred with respect to the understanding in place when First Nations entered into treaties and signed mitigation agreements with the Province. The change is, as previously indicated, the reliance on export sales; initially, the basis for northern generation plants was electricity for Manitobans.

Also, MKO represented the interests of the four northern communities served by diesel generation, and evidenced optimism that the tentative settlement between MH, the Province and the federal government would be ratified and implemented, which would assist with future rate and service prospects for the communities. MKO proposed an accounting treatment to allocate costs to the diesel communities that would recognize the value of the capital assets invested in the service, regardless of contributions to be received from the federal government and other government accounts.

Jurisdiction

CAC/MSOS and MIPUG commented on the jurisdiction of the Board and suggested the Board restrict its directions arising out of the May and June 2006 hearing. The interveners cited particular issues as being public policy matters, best left to government or for consideration as legislation.

All parties agreed that the treatment of the net export revenue in the cost of service study was as much a public policy and fairness issue as it was a cost causation issue. Most interveners also suggested that the Board's directives arising out of the hearing should be fairly tightly held surrounding COSS matters, and that rate design and revenue requirement issues should be left for the next GRA.

4.0 Board Findings

Overview

The Board confirms its public interest mandate, and will provide directions to MH based on the Board's perspective of the public interest. The Board's interests extend beyond arithmetically driven formulaic approaches to evaluating customer class rates and rate setting. The Board intends to consider information on environmental matters, marginal costs, energy efficiency, the plight of low-income customers, those customers damaged by MH's plants and operations, intergenerational equity and the financial strength of Manitoba's largest utility.

Stated differently, the Board is concerned with the financial interest of consumers, electricity rates, intergenerational equity, a properly financed MH, and:

a) the environment, emissions and climate change;

b) fairness for First Nations communities including those relying on diesel generation;

c) fairness for industrial customers having made substantial investments in the Province;

d) attention to the interests of low-income customers, unable to afford energy efficiency upgrades; and

e) the advisability of consumers having a solid and comprehensive understanding of MH's situation, plans and prospects.

That said, by this Order the Board will provide, among other comments and directions, definitive responses to four key COSS questions raised and discussed at the hearing, these being:

a) Should there be one export customer class (as initially proposed by NERA), two export customer classes (as recommended by MH) or some other number of export customer classes?
There is to be one export class.

b) What costs should be directly or indirectly assigned or allocated to the export class?
Costs, including direct, indirect, fixed and variable, are to be allocated to the export customer class in a manner that reflects cost causation, similar to the methodology applied to the domestic customer classes. In particular, costs directly assigned to the export customer class are to include "trading desk" related costs, MAPP and MISO costs, thermal plant costs, purchased power costs, and other costs that are directly attributable to export sales.

c) How should net export revenue be allocated to the domestic customer classes in COSS?
Net export revenue is to be allocated to the domestic classes, including diesel customers, using the methodology recommended by MH.

d) To what degree should the COSS drive future rate decisions?
Supplemental information on carbon emissions costs and marginal cost are to accompany the COSS model based on historic embedded costs. The additional information will allow marginal and environmental costs to be taken into account by the Board in assessing MH's rate proposals. RCC indices both on a pre and post-export credit basis will also be taken into consideration by the Board in establishing domestic class rates. As well, in rate setting, the Board will continue to take into account special circumstances (such as drought, high water flow, etc.); rate stability; energy efficiency objectives; and such other factors and criteria deemed appropriate and consistent with

the public interest. Finally, the Board will continue to rely upon the views and evidence brought before it by MH and registered interveners.

The Board will also direct:

a) the use of twelve SEP time periods rather than four in the context of assigning all generation costs entirely on an energy basis by customer class (MH has indicated a willingness to utilize twelve time periods, and this use will improve the COSS model);

b) generation costs are to be allocated based on energy consumption, while transmission costs are to be allocated on the basis of demand only for both domestic and export classes, rather than energy consumption, as recommended by MH;

c) MH is to consider establishing a new energy intensive industrial class, relative to new energy loads; application to customers will be defined by MH criteria yet to be developed and accepted by the Board;

d) MH is to file additional studies on energy efficiency initiatives, with the implications associated with ending declining block rates and, for industrial customers, initiating inverted and time of use rates (on a revenue neutral basis), and consider the elimination of the winter ratchet;

e) MH is to file a report considering MKO's suggestions, both with respect to cost and rate relief for First Nations customers now incurring rates partially based on mitigation costs, and to MH providing First Nations customers with a greater share of net export revenue based on MKO's interpretations of previous understandings and agreements;

f) MH is to file additional reports related to the diesel class communities, with respect to matters ranging from an assessment of rate fairness to collection practices and experience;

g) MH is to consult with the City of Winnipeg and attempt to achieve a consensus with respect to a fair and equitable allocation of costs with respect to street lighting, and file a report with the Board for review at the next GRA;

h) MH is to consult with the Manitoba Chambers of Commerce with a view to achieving a more significant interface with General Service Small/Medium customers and their rate specific concerns; and

i) MH is to file a 2007/08 and 2008/09 GRA no later than August 1, 2007.

Detailed Considerations

Export Class

To begin with, no party to the 2006 hearing expressed opposition to the creation of an export class. Exports are critically important to MH's financial results and strength, and the costs and revenues of this activity should be determined and segregated, as recognized in past Board Orders and studies by MH and NERA.

MH proposed one export class for firm exports, another for what it defined as opportunity exports; the former was to be allocated costs on the same basis as domestic classes with no direct assignment of costs, the latter allocated only variable costs. The resulting net export revenue would, under MH's recommended model, be allocated across the domestic customer classes.

There was no consensus at the hearing with respect to whether there should be one or two export classes, the latter being recommended by MH, supported by CAC/MSOS and opposed to some degree by MIPUG and RCM/TREE. The Board finds no sufficient reason or differing characteristics pertaining to firm and opportunity sales to support two export classes, and will direct that one export class be established.

The Board's rationale for rejecting two export classes includes:

a) MH's recommended two export class approach does not assign any embedded costs to the opportunity export class, despite strong evidence that opportunity exports are only achievable as a result of over-building hydraulic generation facilities relative to immediate domestic needs;

b) data provided by MH indicated that firm export sales resulted in lower unit export prices than did opportunity export sales during fiscal 2005/06; it would appear that MH's firm and opportunity export sales have been achieving similar average sales prices, though opportunity sales are more volatile as to both volume and price;

c) MH has suggested that firm and opportunity sales are essentially interchangeable in the MAPP/MISO trading area, except that winter off-peak sales are not often associated with short-term firm contracts;

d) while MH suggested that firm sales are made from dependable energy only (dependable energy includes imported power to 10% of committed domestic and export load), additional export sales are secured each year on the basis of more favourable than anticipated hydraulic generation. From a planning perspective, this could be viewed as a modification of the dependable energy definition, because of the inherent expectation of an annual export load;

e) all regularly planned sales may be considered firm energy sales, and failure to achieve some portion of these sales one year out of ten, due to drought, does not necessarily make these sales less firm because in most years these loads are supplied by surplus hydraulic energy;

f) while MH suggests that new plant design for hydraulic generation is not significantly influenced by export considerations, the evidence suggests that domestic load usually requires about 60-65% of actual hydraulic plant generation to satisfy firm energy and capacity requirements. The remaining 35-40% of plant capacity provides for some firm exports in drought years, but primarily serves opportunity export sales;

g) MH indicates that ultimately additional plant capacity above dependable flow will be required for capacity reasons; yet the evidence indicates that dependable energy restraints will continue to require new hydraulic (or thermal or wind) installations and imported power to meet forecast future domestic load. Hence, the amount of capacity overbuild, that is capacity provided over dependable flow, will always be available for exports, those being primarily opportunity sales;

h) current MH planning assures that in the near term there will be energy available for opportunity export sales, and the future plans for new generation facilities suggest this circumstance is intended to continue, the evidence suggests that MH's strategy is for new generation to be put into service to achieve some firm exports and, in most years, significant opportunity export sales;

i) while MH reports that all expansion plans are designed to serve domestic load, the evidence suggests that there is generally a period of approximately ten years when new facilities or capacity (however generated, including DSM efficiencies reducing domestic consumption) will serve exports, and that new plant may even initially entirely be for exports, declining thereafter; and

j) NERA's initially recommended one export class approach essentially treated all export loads on a comparable basis to domestic load, not inconsistent with the way export customers view the sales commitments of MH. MH's suggested distinction between firm and opportunity sale exports may not be shared by MH's export customers, as MISO's requirement for financially firm sales blurs distinctions between domestic load and firm or opportunity export sales.

Accordingly, the Board finds it inappropriate to divide export sales into two classes, allocating only variable costs against one of the classes, the opportunity class, which has recently represented almost 50% of export sales. On an overall system usage basis, firm and opportunity exports employ upwards of 30% and 40% of MH's generation and transmission capacity. This represents a large capacity devoted to exports, and exports, whether defined as firm or opportunity, thus should be allocated substantial portions of embedded costs. The Board has reached a similar conclusion considering generation and transmission assets on an incremental basis.

While MH described net export revenue as a "windfall", the Board sees exports as a natural outcome of MH's planning and operations. MH has set an operational objective of export revenue being 30% of overall annual electricity revenue, and domestic customer rates depend on net export revenues. These are not the signs of "windfall," but of careful planning and deliberate execution. According to MH's latest IFF, no forecast future fiscal year will yield a positive net income without an annual domestic rate increase averaging 2.5% and material export revenues, and those export revenues include opportunity sales.

The simplest and most appropriate approach to reflecting the importance of exports within COSS models is to have one export class, as was originally recommended by NERA. Although NERA has, by way of a brief email to MH, since indicated support for two export classes, a NERA witness was not available for examination at the hearing.

Having one export class for COSS purposes will not prevent economic decisions on opportunity sales being made on the same basis as now employed.

The Board will direct MH to establish only one export class.

Allocation of Net Export Revenue

With respect to another major question, how is net export revenue to be allocated to the domestic customer classes through COSS, the Board finds adequate support for taking all projected prospective costs into account rather than utilizing only allocated generation and transmission costs.

Net export revenue for COSS purposes is to arise after the deduction of all costs associated with export activities, thus, domestic customer classes are relieved of all costs associated with export activities. That accomplished, there is no legislative requirement for net export revenue to be distributed to customer classes within the COSS at all, let alone distributing net export revenue on the basis of generation and transmission costs alone.

Fundamental Change

The Board accepts MH’s contention, not opposed by any of the interveners, that a fundamental change has occurred in the Corporation’s situation and prospects with the advent of a MAPP/MISO trading market. The new market provides not only for the ability to export all generation excess of domestic requirements, subject to transmission restraints, priced on the basis of the marginal cost of generation of MH's MAPP/MISO counter-parties. MH is now able to sell all the power it generates at no lower than the prices established by MISO, which vary each day, hour and five minute block (with peak periods and low off-peak periods).

All parties to the hearing that addressed the topic accepted MH's assertion that SEP prices are a reasonable surrogate for marginal costs for purposes of allocation and classification of generation costs. Yet, on average General Service Large (GSL) over 100 KVA class purchases electricity from MH at an average price below the marginal cost of production, i.e. what MH would receive on average if the power were to be sold outside of Manitoba. While purchase timing may be a substantial issue, there remains a need to appropriately define GSL prices.

This is a powerful argument not only for rate consideration but also for energy efficiency, and, as such, the Board should be aware of the average and variable nature of marginal costs when reviewing and establishing rates.

With increased commodity prices affecting generation costs, (most American utilities in the MISO market utilize coal or natural gas to generate electricity) MH's average export price increased significantly. As well, MH now also has arbitrage opportunities, whereby MH may satisfy an American export customer's required power delivery with an offsetting purchase in the United States, and then sell MH generation to other customers such as Ontario, creating a margin providing a further benefit beyond the original export sale. As a result, MH reported that in its fiscal 2005/06 year the average wholesale export price received exceeded the average rate charged Manitoba customers. With unit export sales prices recently in excess of domestic Manitoba rate schedules, additional consumption in Manitoba reduces export sales bringing about lower aggregate revenues and net income. With MH still well below the Board-approved capitalization target (25% equity), lower net income likely means higher domestic rates over time.

Energy Intensive Industry

MH expressed concern related to energy consumption by energy-intensive firms using energy as a manufacturing input. MH has begun a dialogue with industry over rate adequacy in this new era of higher unit export prices. In this Order, the Board supports MH's concern and directs the establishment of a new industrial class, one that would include new industrial heavy energy consuming firms meeting a to-be-defined profile with respect to time of use, energy consumption and demand.

As well, the Board would be concerned if MH was to take on commitments to supply large amounts of electricity to new industrial firms, and firm export contracts, without quantifiable and significant overall benefits expected to result for Manitoba. Large new energy intensive firms impose risks on MH's other customers, mainly related to rates. And, such new firms may increase potential import and thermal fuel costs with respect to periodic drought situations, while seeking:

a) financially firm power supplies;

b) the lowest energy costs and most favourable terms and conditions; and

c) assured reliability and pricing.

The Board noted the evidence at the hearing that at least one other hydro-electric Crown Corporation, that being Hydro-Quebec, classifies energy intensive firms requiring significant quantities of energy differently than other customers, and may set rates for such firms that are higher than for other firms and customers. While the Board agrees with MIPUG that such an approach could be construed as discriminatory, it holds that such discrimination may be acceptable in a broader public interest context.

As made clear by MIPUG presenters at the COSS hearing, large multi-national firms select locations in part based on energy availability and costs, and can relocate or withhold expansion if circumstances are not acceptable to them. Contrarily, MH's investments in generation, transmission and distribution assets represent a necessarily long-life commitment to Manitoba, with attendant major costs that will be borne by future ratepayers whether a particular plant or firm stays or moves.

To take on the risks of advancing construction of a major new generation station to meet new industrial load or new firm exports at prices below marginal costs and/or the costs associated with the new generation represents a risk and net cost for all of MH's customers. The decision potentially has large economic consequences, and with this Board direction, MH will be in a position to determine what additional price options are available.

Considerable discussion ensued at the hearing concerning how new large industry would be evaluated from a public interest perspective. One option advanced involved comparing the timeframe of energy requirements of the new industry with the employment prospects that would arise from it. The Board is not comfortable with attempting to delineate what level of employment, time of use, or other factor would outweigh considerations related to high on-peak energy demand at less than marginal pricing. Accordingly, the Board expects that MH will consult broadly, and in particular with government and industry, prior to advancing a proposal.

The Board suggests that MH's develop its proposal taking into account that existing industry came, remained and expanded in Manitoba with certain assumptions as to energy pricing and supply. A distinction between new and existing industry is reasonable.

COSS Design and Supplementary Information

The Board accepts the basic process of functionalization, classification and allocation in the COSS model advanced by MH's recommended approach. The historical embedded cost COSS model will, however, be amended as herein directed. Parallel and additional information on marginal costs and carbon emissions will supplement the embedded cost COSS filing, providing the Board with a broader and more comprehensive understanding of matters important to rate setting, fairness between customer classes and environmental concerns.

The Board will consider displaced carbon emissions as well as marginal cost when reviewing the RCC indices produced through the mechanism of an historic embedded cost COSS. The Board confirms that the primary objective of COSS is to <u>assist</u> in the testing of the fairness of rates between domestic customer classes. This objective is met in part by the allocation of MH's prospective revenues and expenses by customer class, in accordance with cost causation, legislation, policy and the public interest.

COSS forms one of three primary components of rate setting, the others being the determination of revenue requirement and rate design. The Board confirms the continued use of ZOR within COSS, with the ZOR range of .95-1.05 to also continue being the test for fairness provided by the historical embedded cost COSS model, excluding and in advance of the consideration of other information and objectives.

The Board will evaluate RCC ratings both pre and post net export allocations. This test will allow the Board to consider what the RCC of each class would be if there either were no export earnings to allocate or net export revenues were distributed in some other manner. In assessing rate fairness, the Board will also consider parallel marginal and environmental cost information. This other information may also prove of assistance with respect to revenue requirement and rate design.

To reiterate, the Board will consider the historic embedded cost COSS, pre and post net export RCC indices, together with marginal and environmental cost information and such other circumstances and factors that it deems necessary in its consideration of future rate proposals. While ZOR readings will be a consideration, neither it nor the RCC indices will be the sole determinant of rates.

Normalized COSS

Noting the significance of the COSS, the Board prefers that the model be based on median water flows, export revenues consistent with average reservoir levels for the start of the fiscal year forecast and unit export prices reflective of “normal” conditions. While domestic consumption and prices as well as MH’s costs are somewhat predictable over the medium term, export revenues and net export revenue varies considerably while being largely outside the control of MH.

The Board will therefore direct that at the next GRA, MH provide detailed information with respect to financial forecasting methodologies used in preparation of the IFF, including preparation of load forecasts, utilization of water flow scenarios, methodologies for forecasting export prices and revenue, and information as to how the effects of drought, including purchased power costs, are reflected in the financial forecasts.

Sustainable Development Act

MH, as a Crown Corporation, and the Board, as a public agency, are both subject to the *Sustainable Development Act* (SDA). The impact of MH on the environment constitutes important "real world" societal factors to be taken into account in establishing rates. Manitoba has remained committed to the Kyoto targets, notwithstanding the federal government's recent wavering.

Energy efficiency and the reduction of domestic consumption are important not only economically, but also from an environmental perspective. However, in saying so, the Board does not infer any level of misunderstanding as to the importance of industry, employment and tax revenue to Manitoba.

Given higher domestic consumption leads to reduced net export revenue, the Board will direct MH to recognize the link between energy efficiency, higher exports and higher aggregate revenue by allocating DSM costs as a direct charge against export revenue. Such DSM costs are to include expenditures funded from a Fund that may be established for DSM purposes pursuant to Bill 11.

<u>Effective</u> energy efficiency measures include initiatives projected to produce net present value from the displacement of lower-priced domestic sales with higher priced export sales. Such measures provide the opportunity for a virtuous circle. Lower domestic consumption may result in higher aggregate net export revenue and net income, lower domestic customer bills, lower carbon emissions in the export market, and an improved debt:equity ratio.

The latter prospective benefit, an improved debt:equity ratio for MH, would reduce long-term pressure on domestic rates. (That said, lower domestic consumption does not generate increased overall revenue through export sales during certain time periods and with respect to certain classes.)

The opportunity for export arises out of excess generation, and that occurs in part because of effective DSM. This change would facilitate the potential for increased DSM activities, when such initiatives are projected to produce net present value, and enhance MH's ability to undertake DSM for low-income customers, where the utility would incur costs furthering export sales with respect to customers unable to upgrade efficiency without assistance. This does not imply that customers should not contribute to energy efficiency measures that provide savings for them; it simply recognizes that DSM can still be effective for the utility when customer contributions cannot be elicited. Such measures are taken in the United Kingdom and Quebec for low-income customers.

The Board accepts that certain other non-carbon emission externalities are either priced into imported power costs or reflected in MH's generation costs (mitigation costs), but these "included" costs are not the end of the story. Global warming is affecting Manitoba as it is the rest of the world, and ignoring it in rate setting is not in the public interest. Climate change brought about by carbon emissions brings particular risks to MH and Manitoba.

It is the Board's understanding, simply put, that:

- since the advent of the industrial revolution, there has been a significant increase of CO_2 in the atmosphere, contributing to and fueling the increase in CO_2 has been industrialization and the consumption of fossil fuels;

- CO_2 "warms" the planet's surface as it absorbs energy (heat), "returning" a portion of it back to the surface resulting in warmer air temperatures, and increased temperatures result in increased evaporation, and increased water vapour also contributes to warmer ground air temperatures, exacerbating the climate change contribution of CO_2;

- temperature increases associated with CO_2 and its effects are expected to be higher as the distance from the equator increases, thus Manitoba and MH's watershed area temperatures may increases more dramatically than temperature increases to be experienced further south; and

- this poses a risk to future water flows and levels in MH's watershed.

The question is not whether to consider environmental externalities, but the level of consideration to be provided. The time to reach conclusions as to the weight to be given to such matters will come with the next GRA and hearing.

It is the Board's understanding that exports of "clean" hydroelectric power from MH displaces firstly natural gas generation and, to a lesser extent, coal generation in the United States, thereby reducing carbon emissions. Towards this end, reduced domestic consumption in Manitoba would allow for increased clean energy exports and reduced thermal generation and emissions in the United States. Progress towards meeting Kyoto and climate change objectives are well served by lower domestic consumption. The Board notes that MH plans to continue operating its Brandon coal plant for some time, and finds that operation to support export sales inconsistent with MH's attention to environmental matters and the SDA, and will direct MH to file a report providing its rationale for its plans to continue to operate the coal plant.

RCM/TREE's witness Mr. Lazar projected a scenario in which an additional 7,000 GW.h resulting from DSM would generate an additional annual export revenue in the order of $388 million, assuming an average sale price of 5.5¢ /kW.h. Contrarily, the Board draws from the evidence that Mr. Lazar's estimate of additional revenue to arise out of increased DSM success in Manitoba is overstated.

It is the Board's understanding that time-differentiated transmission capacity restraints result in a potential maximum of only 6,000 GW.h of additional exports, at a price of not 5.5¢, but 4 to 4.5¢ as perhaps 55% of the additional sales would take place off-peak. From the evidence, the Board surmises that perhaps as much as 75% of the additional exports would have to take place in the winter months, at a time when residential and General Service Small, non-demand load (GSS-ND) accounts for 45% of total domestic load.

Since residential and GSS-ND classes are allocated approximately 75% of MH's distribution costs, the additional net export revenue arising from the sale of an additional 6,000 GW.h may not offset the loss in domestic revenue projections for that volume. Overall, Mr. Lazar's view illustrated the value of energy conservation measures, albeit overstating the magnitude of the potential financial gain.

With respect to emission reduction, in order to displace American coal generation under current circumstances with additional exports provided through DSM success, with few new coal plants designed for "clean coal", the Board suspects MH's pricing would have to be substantially lower than Mr. Lazar's estimate of 5.5¢. MH's generation from the Brandon coal plant for export sale appears to reinforce the impression that coal energy is cheaper than natural gas and competitive with hydro-electric generation. To displace existing base load coal generation in the United States on a sustained basis, the evidence, and the Board's understanding, suggests pricing of additional firm contract load may have to be below 4¢ (2005 dollars).

In short, the Board agrees with CAC/MSOS and finds that the assignment of estimated volumes and costs of carbon emissions by Mr. Lazar far from precise, particularly in comparison with the arithmetically derived prospective historic embedded costs and projected export revenues. From a review of the evidence, the Board concludes that Mr. Lazar’s estimates of additional revenue available with reduced domestic electricity consumption are overstated, yet his concept of considering emission and marginal cost information is important and ought to be taken into account.

As previously indicated, RCM/TREE’s witness assumed that conserved energy would be sold at an average prices of 5.5¢/ kW.h. The Board’s understanding is that most of the conserved energy would have to be during the off-peak periods because of transmission limitations, when SEP prices (reflecting export prices) have recently been in the 2 - 3¢/ kW.h range.

Consequently, in the absence of a major expansion of transmission inter-tier capacity, the average sale price for additional conserved energy would likely be below the 5.5¢ unit export price assumed by Mr. Lazar, assuming no natural gas commodity price spike such as occurred last winter.

Presumably, MH can improve on these estimates and define the specific implications given current transmission constraints, thus allowing RCM/TREE’s concept of considering emissions and marginal costs to be acted on.

CAC/MSOS correctly observed that carbon emissions are only but one of the contaminants arising out of energy production. Nevertheless, the Board accepts RCM/TREE’s contention that carbon emissions are the largest known factor at work, and the one most available to estimate volumes and values. The reduction of carbon emissions is purpose of the European Union’s emissions trading system, which involves credits and wherein a value is placed on each tonne of emission reduction.

The Board will review the information to be supplied by MH with respect to marginal and environmental costs, and, with the assistance of MH and registered interveners to the next GRA hearing reach a conclusion on the weight to be provided to results in rate setting.

Diesel Communities

At one time, in excess of thirty northern communities were provided electricity service by means of diesel-fired generation. Over time, the number of communities served by diesel generation fell to thirteen and, eventually, to the now current four.

The remote Northern Manitoba Communities of Shamattawa, Tadoule Lake, Brochet and Lac Brochet, with a total population of approximately 2,000 people with 800 separate accounts, are not connected to MH's transmission and distribution grid. Diesel generation does not provide the quality of service represented in grid service, as the four diesel class communities receive 60 amp service and are not to use the electricity service for space heating.

In Manitoba, the first 2,000 kW.h of electricity consumed by residential and General Service customers is billed to those customers at grid comparable rates. The subsidy from full cost rates is borne by Government Accounts by way of the premium. In some other Northern Canadian jurisdictions, less than 900 kW.h of diesel generated electricity is provided at grid comparable rates.

As well, excepting for the first 2,000 kW.h of electricity, diesel class rates are very much more expensive than grid rates. Most diesel class customers are residential, but there are also General Service, Federal and Provincial government and First Nations accounts. Because diesel class customers are not serviced by grid connected generation and transmission, and because the cost of diesel generation fluctuates with the market price of diesel fuel, this class has been treated separately for cost of service and rate design purposes. Separate diesel cost and rate studies are prepared by MH from time to time, and filed with the Board for rate changes as appropriate.

In Order 159/04, dated December 22/04, the Board approved interim sales rates for the diesel communities based on MH's Application, which reflected a tentative settlement arising out of MH's negotiations with MKO, acting on behalf of the diesel communities, and Indian and Northern Affairs Canada. The terms of the tentative settlement were summarized in Order 159/04 to include:

1. MH would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit which was approximately $16.9 million as of March 31/04. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement;

2. INAC would pay $3.2 million to MH for the surcharge billed to INAC by MH between November 2000 and May 2004;

3. INAC, on behalf of the Federal government, would pay MH 69% of the $28.8 million of MH's diesel-related capital cost, the balance as at March 31, 2004, by July 7, 2005 without interest and by no later than January 7, 2006;

4. MH would request that other Federal and Provincial government customers in the diesel zone (notably Health Canada, the RCMP, and the Province of Manitoba), pay MH a further 10% of MH's $28.8 million of undepreciated capital costs;

5. MH would assume the remaining 21% of undepreciated capital costs on behalf of residential and General Service customers that are neither First Nations members nor government accounts; and

6. for major future capital expenditures in the diesel zone, MH would consult with the diesel zone's First Nation communities, and secure funding prior to making further capital expenditures.

At the time of issuing Order 159/04 the Board was advised that the signing of the Settlement Agreement was expected on or before July 7, 2005. Because of the change in the federal government and other factors, the date has been delayed, and from the COSS Hearing evidence, the signing of the Settlement Agreement is now expected in the fall of 2006. If the Settlement Agreement is not concluded, MH has indicated a desire to reconsider its recommendation that the class receive an allocation of net export revenue.

The delay relates to the federal government and is beyond the control of the Board, MH and the four communities served by diesel-fired generation. The Board continues to be of the view that supporting the settlement of the outstanding issues is in the public interest.

As noted above, one aspect of the tentative Settlement Agreement was Board approval of an annual allocation of net export revenues over time. This, to, first retire the $16.9 Million (as of March 31/04) diesel zone accumulated deficit, and, once the deficit was recovered, to allow an allocation of net export revenue to reduce costs allocated to this class, thus providing for potentially lower rates than otherwise indicated.

Under MH's current Board approved COSS methodology, net export revenues are allocated to domestic customer classes based on a customer class' share of grid generation and transmission costs. Because customers served by diesel generation are not on the grid and do not share in the allocation of grid generation and transmission costs, the diesel class has not been allocated any net export revenues.

However, under MH's proposed COSS, net export revenues are proposed to be allocated on the basis of total allocated generation, transmission and distribution and other costs, not only on the basis of generation and transmission costs as in the current methodology. Accordingly, MH's proposal provides for an allocation of net export revenue to the diesel class based on the percentage share of total costs that relates to the diesel class.

The inclusion of the diesel class in MH's recommended COSS methodology would expand the number of customers and customer classes that receive the benefit of an allocation of net export revenue. MH maintains such treatment is consistent with the terms of a tentative Settlement Agreement affecting the diesel class, and is also consistent with the fairness principle of allocating a share of net export revenue to all customer classes based on class share of the Utility's total costs.

The underlying indebtedness or cost, against which the diesel class' share of net export revenue is to be firstly credited, has previously been written off for financial statement purposes; therefore, there is no such a cost recorded within MH's financial statements.

For purposes of diesel class Cost of Service and Rate setting, and even after consideration of the government premium, the revenue to cost ratio of the diesel zone is less than 1.0, meaning that grid connected customers would cross-subsidize the diesel class costs. The tentative Settlement also indicates a further cross subsidy of approximately 21% of undepreciated capital costs on behalf of residential and General Service customers in the diesel class that are neither First Nations Members nor government accounts.

The Board is concerned that MH's Recommended Methodology credits a share of net export revenue to the Diesel Class to firstly off-set an indebtedness that MH no longer carries on its financial records. Of further concern is that MH's Diesel Rate Setting Methodology and tentative settlement requires subsidies to be borne by the balance of MH's customers.

The proposal by MH to credit a portion of net export revenue to the Diesel Class needs to be examined further and finalized, in conjunction with a rate review of this class.

The overall impact of MH's Recommended Methodology together with the final terms of any tentative Settlement Agreement, needs to be further examined and reviewed to allow the Board to reach a final determination as to the appropriate allocation of net export revenue to the Diesel Class.

As to MKO's requests that northern customers be relieved from any allocation of mitigation costs and be provided with a greater share of net export revenue, the Board will seek a report from MH based on a careful consideration of the merits of the proposals, which are separate and apart from MKO's proposal with respect to diesel class rates.

Based on MH's evidence, the Board is concerned that the rates for the diesel class may no longer be recovering the class' non-subsidized share of costs – particularly with the increase in fuel costs since the existing rates were approved. MH has indicated an urgency in bringing forward an application to review and possibly revise diesel rates.

The Board will direct that MH file as soon as possible, and by no later than September 30, 2006, a diesel class rate application, to facilitate a review and possible revision of rates for this class. In the interim, the Board will accept MH's recommended methodology with respect to the diesel customer class.

This said, the Board remains open to other COSS methodologies for the diesel class until such time as the Settlement Agreement has been finalized, cost information updated to reflect current diesel rates and revenue, and a current diesel rate application is before the Board.

With the upcoming diesel class rate application, the Board will also direct that MH provide reports on:

a) the fairness of the rate approach with respect to non-senior government accounts (the Board is concerned that the rates restrict the economic development prospects for the communities and drive up service and commodity costs, damaging residents);

b) the efficacy of the current rate schedule for non-government accounts (data on aged accounts receivables, delinquency and bad debts together with the collection policies in place for the four communities will be required) – the Board is concerned that the current approach may be untenable;

c) the effects of the current approach to rates and consumption restrictions on the four communities; and

d) the cost that would be incurred to upgrade service to the four communities, to provide 200 amp service and access to space heating by electricity.

MH Capitalization

The Board is concerned with MH's present capitalization and notes MH's comment that net export revenue represents a form of "windfall" which cannot be guaranteed to continue at recent levels. Even though net export revenues have been significant over the past decade, progress towards the debt:equity target of 75:25 is slow. This is important as MH's IFF forecasts may exaggerate net income prospects over the next ten years, as the deleterious financial impact of a drought can exceed the expected potential of the opposite, extraordinary high water flow. In short, the worst expected result, that to arise with a drought, may be anticipated to produce losses in excess of the increased net income to arise from extraordinary good water flow years.

The Board notes that, notwithstanding the serious drought of 2002/04, water supply levels over the past 10 to 15 years have been above median levels. If the next 10 to 15 years bring lower water flows than the median, MH's current forecasts of future net income, driven in large part by anticipated export profits based on median water flow, may not be achievable.

That said, the Board rejects MIPUG's recommendation to require MH to restrict retained earnings to serve as a specific drought reserve. MH faces many risks (going beyond water levels and storage, and export pricing), and drought is, though a material risk, but one. The debt:equity target of 75:25 recognizes the need for equity, and MH has testified that a sizeable equity level is required solely to meet risks and provide for rate stabilization. To hold to the 75:25 target and set aside a further provision for drought would be to double-count, and is not necessary.

However, the Board accepts that there needs to be more rigor in the examination and evaluation of MH's risk estimates, and there is a long list of other risks, some posing financial implications as great as or greater than the risk related to drought. To test the adequacy of the 75:25 debt:equity target, and to better inform decision-making with respect to setting aside a portion of annual net export earnings to build retained earnings (i.e. to know how much to set aside and for how long), the financial risks identified by MH need to be quantified and tested through examination in a GRA hearing.

Further complicating the situation is the Board's concern with respect to the "soundness" of MH's retained earnings. As previously indicated, by Order 143/04 the Board expressed reservations concerning MH's deferral of period expenditures, and compared MH's accounting policies with respect to DSM and planning studies to less liberal approaches in other hydro-electric Crown Corporations (Hydro-Quebec and B.C. Hydro). While MH defers significant period expenditures and amortizes deferred costs over fifteen years, the other Crowns either absorb such expenditures in the current period or amortize them over five years. The Board also notes that the other Crowns not only amortize such expenses more quickly than MH, but also have lower debt:equity ratios than MH (i.e. the equity component of the other Crowns' capital structures are higher).

While the Board accepts that MH's accounting policies meet the test of generally accepted accounting principles, it prefers a more conservative approach. An in-depth examination of MH's accounting policies is appropriately best conducted at a GRA rather than a COSS methodology hearing. However, the Board places MH on notice that the Board intends to conduct a detailed examination of certain accounting policies related to capitalization and deferrals, at the next GRA. If appropriate, the Board will consider the merits of adopting different, more conservative, accounting policies for regulatory purposes, to also be reflected in future cost of service studies.

The Board noted the testimony of MH that the thermal generation natural gas plants in Selkirk and Brandon are rarely operated, and then basically for training and maintenance reasons. MH indicated the plants were uneconomic, due to the design and increased cost of natural gas. Since the thermal gas plants were constructed, natural gas commodity prices have increased from $2 GJ (a GJ being a unit of measure for natural gas) to, now, $5-6 GJ (with a spike to in excess of $15 GJ). While the Board understands that the gas thermal plants, regardless of the cost to operate, have some business value by being available in emergencies, the Board notes no evident direct net present value with respect to future generation and sales from the plants.

Thus, for purposes of strengthening and assessing the adequacy of MH's retained earnings, the Board, at the next GRA will consider the appropriateness of certain accounting policies and their impact on MH's retained earnings for regulatory purposes.

Bill 11 now provides for the creation of a Fund representing between 5% and 10% of MH's 2006/07 export revenues, to be used to meet the costs of further DSM initiatives. For future COSS models, the Board will require MH to deduct expenditures made from the Fund from the amount of net export revenue otherwise to be credited to the customer classes. As well, the Fund is to be deducted from MH’s retained earnings, and is not to form a component in calculating MH’s debt:equity ratio in future GRA proceedings.

While the Fund, assuming it leads to DSM initiatives having a positive present value taking into account prospective export revenue, may be expected to contribute to higher future net export revenue and net income, the Board will not assume net income before it is realized.

Throughout this Order there are numerous reference to the increasing risks in MH's business environment, and to the increasing importance of MH improving its financial strength, and in particular, its debt: equity ratio, to achieve its 75:25 target as quickly as possible. To accomplish this end, and as reflected in the IFF's filed with the Board, there is an expectation of annual rate increases in the range of 2.5%.

In advance of thoroughly examining MH’s forecasts in a GRA, the Board observes that annual increases in that range do not appear to be unreasonable given MH’s capital situation and risks. The Board further suggests that the previous history of MH not applying for relatively modest and inflation-level forecast rate increases because of “good years” due to high water levels and favourable export sales and prices have contributed to the current capital inadequacy.

The Board notes that multi-year rate applications, two years as suggested herein, or three, would bring a higher level of certainty to MH's ability to stay on target in achieving its financial target. The Board’s hearing processes provides an opportunity for the achievement of a higher level of Board and public understanding of MH results and prospects, and the avoidance of gaps in the knowledge base which have developed in the past with long MH absences from appearing before the Board. The regulatory savings resulting from long periods between hearings before the Board are offset by the deficiencies represented by reduced regulatory oversight of Manitoba’s largest utility.

Taking all factors into consideration, the Board believes that two year rate applications and hearings strike an appropriate balance between ensuring appropriate rates and regulatory efficiency. The Board will further direct that MH consider future general consumer rate increases greater than the 2.5% annual increases set out in the IFF, to reflect the concerns with respect to expediting achievement of the financial targets.

Testing New COSS Design

The Board will direct MH to file a COSS prepared in accordance with the Board's directions by November 30, 2006, including any explanatory commentary as MH wishes. The Board will review the model and explanatory comments received from MH and may either, and prior to MH filing a GRA, confirm its COSS design direction or indicate amendments.

The Board lacks the detailed information available to MH to model the effect of the cost allocations to be made against the export class as well as the effects to arise out of the other changes to COSS directed by the Board on the overall resulting COSS. Information not now available to the Board includes the projected impact of utilizing twelve rather than four time periods in allocating generation costs, the direct allocation of certain costs against export revenue, and the forecast of DSM costs to be drawn from the Energy Fund arising out of Bill 11.

In addition, MH has yet to issue its annual report with audited financial statements for fiscal 2005/06 and the Board is unaware of the export revenue development to-date in fiscal 2006/07.While this latter information has no direct application to the directives relating to COSS design, the Board believes it critical to its overall understanding of MH's situation.

Profits and Use

In Board Order 143/04, the Board suggested to government that the declaration of dividends to the Province be suspended, at least until such time as MH had reached its debt:equity ratio target of 75:25 and dividend-enabling legislation was in place.

That said, and noting that MH has not reached the debt:equity target, the Board does not share the general view that the only use of future MH profits need be restraining or reducing rates, or building retained earnings.

City of Winnipeg

The City of Winnipeg is a large customer of MH, and was the previous owner of Winnipeg Hydro, recently acquired by MH. The acquisition agreement included significant financial terms and an arrangement that committed MH to a number of actions including the building of a downtown head office and the expenditure of $8 million over ten years to improve the energy efficiency of the City's operations.

The City seeks amendments to the cost allocation process with respect to the customer service function and a rate reduction to the street lighting class to bring the class within the ZOR as to rates. Given the magnitude and complexity of the relationship between MH and the City, the Board is surprised that MH and the City have not reached a consensus on appropriate rates for street lighting, and the assumptions underlying the rate schedule, to bring to the Board.

Accordingly, the Board will direct MH to consult with the City and bring forward a proposal to the next GRA to resolve the dispute with the City in an appropriate manner fair not only to the City and MH, but also to MH's other customers.

Other Issues

Turning to other issues reviewed at the COSS hearing, the Board will provide MH with further directives related to rate design for the next General Rate Application, these to include MH filing with the Board by November 30, 2006:

a) a proposal to end declining rate blocks, this to be accomplished on a revenue neutral basis;

b) a proposal to implement inverted rates for the GSL over 100 KVA class and the large energy user, also on a revenue neutral basis under the assumption that energy consumption remains static;

c) a proposal to consolidate GSS/GSM/GSL < 30 kV and other sub-classes, on a revenue neutral basis;

d) a proposal to establish a new class to hold new industrial customers with anticipated high annual energy consumption and demand requirements, and to provide criteria pursuant to which members of the class would be selected. The proposal should also include a proposal for a rate for this new class representative of marginal costs, reflective of "Time-of-Use" i.e. average unit sale prices for exports;

e) a report on the implementation of "Time of Use" meters and billing for industrial and other large energy users; the Board encourages MH's research into this promising area potentially furthering efficiency goals;

f) a report considering the appropriateness of the current split between energy and demand charges, towards enhancing energy efficiency gains for industry and enhanced export potential for MH;

g) a report considering incentives designed to encourage industry to move further forward on efficiency opportunities;

h) an update of the Power Resource Plan, specifically addressing thermal plant upgrade and retirement plans and implications, other generation and transmission plans, with timelines;

i) a report updating the revenue and cost projections filed with the Clean Environment Commission with respect to Wuskwatim;

j) a report providing supporting detail for MH's projections of domestic load reductions projected to arise from DSM;

k) a report on Kyoto's relevance to MH and environmental strategies with respect to Kyoto compliance; and

l) a quantitative Risk Analysis with particular emphasis on the marketing, operational and financial risks associated with droughts and including drought shortfall-import pricing (i.e. supporting evidence for the $2.2B estimate for a five year drought).

Finally, the Board anticipates reviewing a number of issues and matters that were the subject of past Board Orders at the next GRA, these including the possible elimination of the winter ratchet; and the review and possible revision of the Limited Use Billing Demand Program.

5.0 IT IS THEREFORE ORDERED THAT:

1. The Cost of Service methodology recommended by Manitoba Hydro BE AND IS HEREBY APPROVED, subject to the following amendments:

   a) There shall be one export customer class, instead of the two export customer classes recommended by Manitoba Hydro.

   b) Costs, including direct, indirect, fixed and variable costs, are to be allocated to the export customer class in a manner that reflects cost causation, similar to the methodologies applied to the domestic customer classes. In particular, costs directly assigned to the export customer class are to include "trading desk" related costs, MAPP and MISO costs, thermal plant costs, water rental and purchased power costs, and other costs that are directly attributable to export sales.

   c) Twelve SEP time periods are to be used in the determination of marginal cost weighting, rather than the four time periods proposed by MH.

   d) In addition to the Uniform Rate adjustment, Net Export Revenue is to be further reduced by DSM costs and by the allocation required by Bill 11, prior to allocation to the domestic customer classes.

   e) The diesel customer class is to be included in the Cost of Service Study, as recommended by Manitoba Hydro.

   f) Net export revenue is to be allocated to the domestic customer classes, including diesel customers, using the methodology recommended by Manitoba Hydro.

2. Future Cost of Service filings should also include supplemental information by customer class, including approximate revenue to costs ratios, related to the inclusion of marginal cost information and the allocation of notional environmental emissions costs.

3. Manitoba Hydro is to refile PCOSS-06 as soon as possible, but no later than November 30, 2006, updated to reflect the above decisions and methodology changes together with explanatory commentary. The filing is to also include a preliminary outline of the supplemental information to be filed related to marginal and environment costs.

4. Manitoba Hydro shall file with the Board the following information and reports by no later than April 30, 2007:

   a) A report and recommendations with respect to establishing a new energy-intensive industry class, including criteria developed after broad consultation with industry and government, and rate design recommendations.

   b) A report and recommendations to phase out or eliminate the declining block rate schedules.

   c) A report and recommendations with respect to rebalancing demand and energy charges.

   d) A report and recommendations to introduce inverted rates for large volume consumption customers, including winter ratchet considerations.

e) A report and recommendations to establish time of use rates for non-residential customer classes, particularly large volume customers.

f) A report with respect to consultations with the City of Winnipeg concerning customer counts and overall cost allocations to the street lighting customer class.

g) A report with respect to Manitoba Hydro's plans concerning the Brandon coal-fired generation plant, and the rationale for continued operations of that plant in light of the Sustainable Development Act.

h) A report with respect to consultations with MKO and the federal government with respect to MKO's proposal for an additional sharing of net export revenue and its suggestion that rates charged such communities should be reduced on an ongoing basis to reflect the removal of the cost responsibility for certain mitigation costs.

i) A risk analysis report that analyses and quantifies MH's $2.2B loss estimate for a five year drought, including marketing, operational and financial risks and the potential impact of drought shortfall import costs such as those experienced in 2003/04.

j) A report and recommendations with respect to customer class consolidation options and appropriate rate differentials for various customer sub-classes.

5. Manitoba Hydro shall file, as soon as possible, but by no later than September 30, 2006, a Diesel Rate Application, which shall include the following information and reports:

a) A status update of the Settlement Agreement.

b) A discussion of the rate approach with respect to non-senior government accounts.

c) Current information with respect to non-government accounts including aged accounts receivable, bad debts information, and collection policies and procedures.

d) Information with respect to the current approach to rate setting and consumption restrictions.

e) Current information with respect to estimated costs required to upgrade services in the four diesel communities to provide 200 amp and space heating service capabilities.

6. Manitoba Hydro shall file a General Rate Application for the fiscal years 2007/08 and 2008/09 by no later than August 1, 2007 which shall include the following information:

a) Updated Cost of Service information reflecting the revised methodologies set out herein.

b) Consideration of future general consumer rate increases greater than the 2.5% annual increases set out in the IFF, to reflect the concerns expressed by the Board and others with respect to expediting achievement of the financial targets.

c) Detailed discussion, information and support with respect to accounting policies related to capitalization and deferral of expenses, including planning studies, DSM costs, capitalization of overheads, mitigation costs, and accounting for plant costs related to uneconomic generation with limited expected remaining life (such as the Brandon and Selkirk generation plants).

d) Detailed discussion and information with respect to financial forecasting methodologies used in preparation of the IFF, including preparation of load forecasts, utilization of water flow scenarios, methodologies for forecasting export prices and revenue, and information as to how the effects of drought, including purchased power costs, are reflected in the financial forecasts.

e) An updated power resource plan including the proposed role of wind and Wuskwatim Generating Station, and depicting the potential role of Gull and Conawapa.

THE PUBLIC UTILITIES BOARD

"Graham F. J. Lane, C. A."
Chairman

"H. M. Singh"
Acting Secretary

Certified a true copy of
Order No. 117/06 issued by
The Public Utilities Board

Acting Secretary

Appendix A

Appearances

R. Peters	Counsel for The Manitoba Public Utilities Board (Board)
O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board (MH)
J. Feldschmid	Counsel for Canadian Centre for Energy Policy Incorporated (CCEP)
B. Williams M. Bowman	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc. (CAC/MSOS)
T. McCaffrey	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson	Representing Manitoba Keewatinook Ininew Okimowin (MKO)
P. Miller	Representing Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Buhr	Counsel for the City of Winnipeg (City)

Appendix B

Witnesses for Manitoba Hydro

V. Warden	Chief Financial Officer, Vice President, Finance and Administration
H. Surminski	Section Head, Resource Planning and Market Analysis, Power Generation System Studies
R. Wiens	Division Manager, Rates and Regulatory Affairs
D. Cormie	Manager, Power Sales and Operations Division, Power Supply
C. Thomas	Supervisor, Cost of Service, Rates and Policies Department
W. Hamlin	Energy Policy Officer

Appendix C

Interveners of Record

1. Canadian Centre for Energy Policy Incorporated (CCEP)

2. City of Winnipeg (City)

3. Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors (CAC/MSOS)

4. Manitoba Industrial Power Users Group (MIPUG)

5. Manitoba Keewatinook Ininew Okimowin (MKO)

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

Note: Interveners 1, 2, 3, 4, 5 and 6 participated to varying degrees throughout the hearing and presented final comments. Interveners 3, 4 and 6 presented witnesses.

Appendix D

Intervener Witnesses

CAC/MSOS

W. Harper	Manager, Econalysis Consulting Services, Inc.

MIPUG

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

RCM/TREE

J. Lazar	Consulting Economist, Micro Design Northwest

Appendix E

Presenters

B. Turner	Chairman, MIPUG; Plant Manager, Canexus Chemicals
D. MacDonald	Energy Manager, Gerdau Ameristeel Mb Northeast Operations
D. Markham	Executive Vice President, Mining Association of Manitoba

Appendix F

Glossary

Crown Corporation	A corporation or other body to which The Crown Corporations Public Review and Accountability Act applies.
Demand	The size of any load, expressed in kilowatts, averaged over a specified period of time.
Demand Side Management	Measures implemented to influence the amount of resources consumers use, as well as how and when the resources are used.
Energy	The ability to do work. Electrical utilities sell electrical energy to their customers who, in turn, convert this energy into a desirable form – such as work, heat, light or sound.
Environment	Includes air, land, water, flora, and fauna.
Export load	Any electricity that is generated in excess of provincial needs and is sold to out-of-province energy markets.
Firm power	Power (electricity) that must be supplied as agreed under contract, even under adverse conditions.
Full Cost Accounting	Accounting for the economic, environmental, land use, human health, social and heritage costs and benefits of a particular decision or action to ensure no costs associated with the decision or action, including externalized costs, are left unaccounted for.
Generator	A machine that converts mechanical energy – such as a rotating turbine driven by water or steam or wind – into electrical energy.
Gigawatt (GW)	The unit of electrical power equivalent to one billion watts or one million kilowatts.
Gigawatt hour (GW.h)	A unit by which electrical energy is measured. It is equal to one million kW.h (see definition below)
Grid (Power)	A number of interconnecting electrical power systems which link together electrical utilities covering a large geographical area.
Interconnections	Powerlines that interconnect one electrical utility's power

	system with another.
Kilovolt (kV)	The unit of electrical pressure, or force, equivalent to 1,000 volts (V).
Kilowatt (kW)	The unit of electrical power equivalent to 1,000 watts (W).
Kilowatt-hour (kW.h)	A unit by which electrical energy is measured. For example, 10, 100 W light bulbs switched on for one hour would use one kilowatt-hour (1,000 W for one hour).
Load	The amount of electricity required by a system or piece of equipment at a given instant.
Megawatt (MW)	The unit of electrical power equal to one million watts or 1,000 kilowatts (kW).
Peak Load	Record of maximum amount of electricity used in a given time period.
Power	The rate of using electrical energy, usually measured in watts, kilowatts, or megawatts.
Transmission system	The towers and conductors that transport electricity in bulk form from a source of supply to either local areas for distribution, or to power systems of out-of-province electrical utilities. Electricity is usually transported via transmission lines in amounts ranging from 66 kV to 500 kV.
Volt (V)	The unit of measurement of electrical pressure, or force, which causes electric current to flow.
Watt (W)	The unit of measurement of electrical power.