M A N I T O B A	Order No. 112/09
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	July 10, 2009

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

AN ORDER WITH RESPECT TO MANITOBA HYDRO'S APPLICATION FOR AN ENERGY INTENSIVE INDUSTRIAL RATE

Contents

EXECUTIVE SUMMARY

Manitoba Hydro (MH) has a mandate to provide for the continuance of a supply of power adequate for the needs of the Province, as well as to promote economy and efficiency with respect to the end-use of that power. Additionally, MH markets power to persons outside the Province through its export program.

In carrying out its domestic and export functions, MH maintains it can make more revenue by selling an extra kilowatt hour of energy on the export market, rather than selling that same kilowatt hour of energy to a domestic customer, especially if that domestic customer is an industrial customer. Therefore, virtually all increased electricity consumption by Manitobans negatively affects MH's revenues, because energy to serve domestic energy load growth is diverted from profitable export markets. That revenue reduction could be more pronounced if large, energy-intensive industries either undergo major expansions, or locate in Manitoba to capitalize on MH's low domestic electricity rates.

MH is proposing a new "Energy Intensive Industrial Rate" (EIIR) to apply for energy used by an industrial customer above an established baseline quantity.

Consumption below the baseline quantity would continue to be charged the lower "embedded cost rates", with additional growth and expansion-related energy being charged a "higher marginal cost" rate.

While some aspects of MH's EIIR proposal have merit, other aspects are not fully satisfactory to The Public Utilities Board (Board) on a principled basis. Therefore, MH's Application for a new EIIR is denied in this Order.

Also in this Order, the Board provides the parameters for a new EIIR proposal to be developed by MH in consultation with Stakeholders. That proposal would see General Service Large (GSL) customers (served at 30 kV and greater) subject to an EIIR, but only for on-peak energy load growth above an established baseline. In the determination of the customers' baselines, the Board preserves the date of March 31, 2008 for the application of EIIR. For reasons set out later in this Order, such a new rate would promote energy efficiency and conservation in Manitoba.

To address the concern that MH and most Interveners shared (respecting large energy-intensive industry load growth having a significant impact on the need to advance new generation and transmission), the Board is requesting MH to present, following consultation with Stakeholders, a new System Expansion Policy which incorporates capital contributions by the Utility, based on expected customer revenues, to offset system upgrade costs, together with a requirement for specific customer capital contributions toward generation and transmission costs for substantial load additions.

In addition to the Board's directed EIIR and System Expansion Policy, the Board invites MH and Stakeholders to present additional principle-based options for consideration by the Board.

1.0 Background

Manitoba Hydro (MH) filed an Application on September 30, 2008 seeking Board approval of a new Energy Intensive Industrial Rate (EIIR). A public rate hearing was held during 8 days from December 8, 2008 through January 22, 2009.

The Interveners to the process were:

- Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc./ Winnipeg Harvest (Coalition);
- Manitoba Industrial Power Users Group (MIPUG);
- Manitoba Keewatinook Ininew Okimowin (MKO); and
- Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE).

In addition to the Interveners, four individual presentations were made, each expressing particular concerns from industry in Manitoba and providing recommendations. As presentations are not evidence, and the views expressed are not subject to cross-examination, presenters can only provide the Board with different perspectives, often providing background context for further research or examination.

This Order provides the Board's findings, recommendations and directions on matters of interest arising in the course of the hearing process, which included oral testimony and filed documentary evidence.

Hearing transcripts are posted on the Board's website, www.pub.gov.mb.ca, and, together with the Board's files of evidence presented as exhibits, provide public access to the full record of the hearing, including cross-examination of MH's and Interveners' witnesses by the Board, MH and Interveners.

The EIIR Application has its roots in prior proceedings before the Board.

1.1 MH's 2004/05 General Rate Application

In its justification for April 2, 2004 and April 1, 2005 rate increases to all customer classes, MH submitted that its domestic rates were less than market prices in nearby inter-connected markets, and also noted that MH's domestic rates had not been increased for a number of years. At the time of MH's 2004/05 General Rate Application (GRA), MH's rates were, on average, the lowest of any utility in North America.

As noted by the Board, in Order 143/04 (at page 48):

> *"Both MH and certain Intervenors suggested that low domestic rates may encourage more domestic consumption and attract energy intensive industry to the Province, which would reduce revenue as profitable export sales are foregone."*

Therein lies the problem - or more accurately the two problems - that MH's current EIIR Application seeks to address:

<u>First</u>: MH's low domestic rate may encourage more domestic consumption, rather than energy efficiency; and

Second: MH's low domestic rates may attract energy intensive industry to Manitoba.

Both of the above scenarios have the potential to reduce MH's total revenue if export sales, recently reported to be at an average of 5.5¢ per kW.h, are foregone by selling such electricity to large non-residential domestic customers whose rates only recover bulk power costs of between 3¢ and 4¢ per kW.h.

1.2 MH'S 2006 Cost of Service Study Methodology Review

Following the 2004 GRA proceedings, the Board conducted a hearing in 2006 to review MH's Cost of Service Study Methodology and noted in Order 117/06, on pages 54 and 55:

> *"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 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 firms, and firm export contracts, without quantifiable and significant overall benefits expected to result for Manitoba.*
>
> *Large new 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…..

Considerable discussion ensued at the hearing concerning how new 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 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.

Included in Order 117/06 was the Board's directive that MH file:

> *4 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.*

The Board's main concern at the time of the Cost of Service Study Review was with the prospect of new energy intensive industry locating in Manitoba to utilize low-cost electricity, at the expense of foregone export sales that would yield higher revenues to MH. MH utilizes net export revenue as a credit against each domestic class's underlying costs, thereby reducing the cost-based rates charged to Manitoba's electricity consumers.

1.3 MH's 2008/09 General Rate Application

Following the Board's direction from the 2006 Cost of Service Study Methodology Review Order, MH included, in it's 2008/09 GRA, a request for new general service large rates for new or expanding loads. Perhaps it was in this Application that the focus of the newly proposed EIIR became clearer, and was targeting certain existing Manitoba industrial customers, more so than potentially new energy-intensive industries that may seek to locate in Manitoba to utilize low priced electricity as a manufacturing input.

In the first of two Orders in response to MH's 2008/09 GRA, the Board indicated in Order 90/08 (pages 14 and 15):

> ***4.3 New rate for energy-intensive industrial users***
>
> *In its GRA, MH proposed a rate for new and expanded energy intensive industrial users that would be based on marginal cost, defined by MH as the forecast price available on the MISO export market for an additional unit of generated and transmitted electricity.*
>
> *The proposed new rate approximated 6.4 cents per kW.h, and represented a significant increase over the current average price charged large industry of approximately 3.2 cents per kW.h. Included in MH's proposal was exemption criteria that, if met, would allow expanding existing and new energy-intensive customers an opportunity to be exempt from the new rate. The exemption criteria were designed to consider economic value to the provincial economy to be associated with the new industrial load.*
>
> *In short, pursuant to MH's proposal, new and expanding energy intensive industries requiring significant power would be subject to criteria to be applied in order to determine whether or not they would receive a "heritage" rate based on historical embedded costs (for large industry) or be required* to *pay much higher rates, based on marginal costs. The primary argument advanced in support of the proposal was the contention that MH could, in the absence of increasing industrial load, sell the power at a higher price on the export market, and that increasing industrial load results in lower net income for MH, and higher rates for all domestic customers.*
>
> *Following considerable evidence and discussions, with Interveners challenging MH's proposal and rationale, MH withdrew its application, indicating that it would re-file its proposal following further consultation with affected parties.*

The EIIR, as proposed at the 2008/09 GRA, would have applied to all large energy load expansions, subject to allowances for growth, Power Smart initiatives, environmental compliance and provincial economic benefits. The GRA proposed that EIIR would not apply to new loads or expansion of loads associated with government accounts, and other public sector infrastructure such as water and waste-water treatment plants.

Beyond customer specific baseline energy quantities, higher rates based on the marginal value of the energy would be charged under the proposal brought forward at that GRA, unless the industrial customer qualified for an exemption based on economic considerations such as the economic value to the provincial economy of the new or expanded industrial load.

In it's 2007/08 GRA, MH proposed to offer a choice among criteria, to evaluate whether new General Service Large loads or load expansions provide sufficient provincial economic benefit to merit exemption from the application of marginal cost based rates to loads above baselines.

In that proposal, the exemption from marginal cost rates would be extended to above baseline load growth, if:

a) The sum of Incremental Direct Payroll plus contract labour is 3 times the incremental cost of new or expanded load to all ratepayers; or

b) The sum of Incremental Direct Payroll, plus contract labour, plus incremental taxes paid to Manitoba or a Manitoba municipality is 4 times the incremental cost of new or expanded load to all ratepayers; or

c) The sum of current total Direct Payroll, plus contract labour, plus taxes paid to Manitoba or a Manitoba municipality, is 20 times the incremental cost of new or expanded load to all ratepayers. This option would normally apply only if a load increase does not expand production at a customer's plant, but is required to support and maintain existing operations.

The Incremental Cost of new or expanded load to all ratepayers was then defined as: Incremental Energy Consumption x [Marginal Cost of Generation & Transmission ($/MW.h) less Average Rate for GS Large Customer Class ($/MW.h)]

2.0 MH'S EIIR Application of September 30, 2008

Having withdrawn its EIIR request from consideration at the 2008/09 GRA hearing, MH filed its modified EIIR request with the Board on September 30, 2008. MH's EIIR Application contained material changes to its previous application and can be summarized as follows:

2.1 Overview

MH applied for approval of a new Energy Intensive Industrial Rate schedule applicable to non-government General Service Large (GSL) customers served at 30 kV and above (GSL>30 kV), and which use 100 GW.h or more of energy annually. Baseline energy amounts would be supplied at the same embedded cost-based rates, or "heritage" rates-as are applicable to all GSL customers.

Beyond the specific baseline energy quantities, which are unique to each customer, higher rates (intended to be reflective of marginal energy cost) would be applied.

Existing customers, aggregated with their Manitoba-based affiliated companies, would be entitled to their current baseline energy consumption at the Board-approved initial block GSL heritage energy rate, up to a maximum baseline of 1,500 GW.h, including Power Smart credits and future environmental credits. Consumption above that level would be subject to the tail block energy rate, which is intended to be reflective of marginal cost.

2.2 Customer Baseline Energy Level (CBEL)

MH's previous proposal included a baseline of 39 GW.h with additional consideration for exemption of further consumption based on criteria related to economic considerations. MH's most current proposal excludes economic exemption criteria but includes a higher baseline (of 100 GW.h).

The proposed calculation of a Customer's Baseline Energy Level (CBEL) is summarized as:

- Maximum 12 consecutive month energy consumption in the 36 months ended March 31, 2008

  PLUS

- Verified Power Smart energy savings from April 1, 1992 to March 31, 2008, other verified energy-efficiency project savings, non made-up load curtailment energy, and load displacement generation energy

  PLUS

- Additional energy consumed by an energy-efficient solution, other than fuel switching, which is required for compliance with or anticipation of any federal or provincial act or regulation or government-issued guidelines with respect to environmental objectives.

And, pursuant to MH's proposal, if a customer was able to demonstrate that unusual conditions applied during the entire 36-month reference period, an earlier period could be chosen to establish the initial baseline (to allow the company a higher initial baseline).

New companies locating to Manitoba would be entitled to up to 100 GW.h of annual energy consumption at the initial block General Service Large energy rate, while consumption above that level would be subject to the tail block energy rate.

The new rate schedule would neither apply to provincial and municipal government accounts nor to other public sector infrastructure, such as water and waste - treatment plants, hospitals and schools.

2.3 Baseline Growth Allowance

A customer's CBEL would be adjusted upward by 3% annually for the first five years. Thereafter, annual baseline growth would be limited to the lesser of the customer's actual increase in energy use during the previous year in excess of the previous year's CBEL, or 2% of previous year's CBEL to a maximum baseline, of 1,500 GW.h.

To allow for above-average short-term growth, with one year's written advance notice, customers would be allowed a one-time step increase in their baseline of 10% of the prior year's CBEL. The new baseline would be maintained at that level until the annual baseline growth allowance (as noted above) otherwise applied to the baseline equals the stepped baseline.

Baselines would be calculated for individual companies and then aggregated with their Manitoba based affiliated companies. For customers with multiple accounts, energy consumption above their corporate aggregated baseline would be calculated and billed to the individual electricity accounts proportionately, at the appropriate rate class, based on the annual energy consumption of the individual account.

Pursuant to MH’s proposal, any company’s unused growth allowance could not be bought, sold or transferred to another company to increase the other company’s CBEL. If a company grows through acquisition of an existing Manitoba Company, its aggregated CBEL would increase by the amount of the acquired company’s CBEL. Acquired business must be ongoing in nature, or must be integrated into the other company’s operation, and the purpose of the acquisition could not be to avoid higher electricity costs.

3.0 Specific Issues

3.1 Perceived Problems

3.1.1 MH Position

MH has concerns that the current prices for industrial energy usage fall substantially below the fair market value as portrayed by MH's recent export energy sale prices. Such a situation was indicated to represent a reduction in potential utility income, a reduction that, consequently, would have an impact on other customer rates. According to MH, the potential revenue shortfall equates to about 2.2¢/kW.h (5.5¢/kW.h versus 3.3¢/kW.h) at then-current export prices and rates for GSL >100 customers.

MH reported an expectation that rapid growth in the industrial sectors (particularly the chemical and petroleum transport sectors) will continue to escalate the revenue shortfall.

MH's EIIR proposal is intended to capture the price-rate difference on most of the future load growths. Coincidentally, the proposal targets four customers in the chemical and petroleum transport sectors, although as many as ten customers could theoretically be affected if their consumption levels were to increase at more than 3% per year.

3.1.2 Examination of Evidence

The evidence presented in this hearing confirmed that industrial energy consumption since 1999 increased at a substantially-greater rate than the rate of consumption growth of either the residential or commercial customer classes.

It is noted that residential usage increased by about 800 GW.h between 1999/00 to 2005/06, and then rose by another 800 GW.h from 2005/06 to 2007/08. Industrial growth increased by 1,900 GW.h from 1999/00 to 2005/06, but by only 200 GW.h from 2005/06 to 2007/08. Overall, consumption has increased by 25% for the residential class, and by 50% for the industrial group, over the eight-year period.

More significantly, the consumption of the four targeted customers grew by 100% over the same period and accounted for essentially all the growth among the ten largest customers. Increasing their load from 1,300 GW.h to 2,600 GW.h in eight years, these four customers added almost as much load as the entire residential class.

While it appears from MH's filings that the more than 150 GW.h/year growth trend for the industrial sector (and these four customers in particular) is expected to continue for the next five years, there is little specific evidence to support this suggestion. If one (or two) of these four customers were to cut back or halt their anticipated growth plans, the expectation would change to one of minimal overall industrial growth.

Despite MH's prior concerns about large new energy intensive customers poised to take advantage of the low industrial customer rates, there is still only a suggestion by MH that one new customer using 100 GW.h or more may locate in the Province. This forecast may reflect the record of the last ten years, when only one new customer of that magnitude of annual consumption was attracted to the province.

It could be argued that the rapid expansion of the Canexus Chemicals Canada Inc. (Canexus) operations to a 1,500 kW.h consumption level over a six-year period is indicative of the risk faced by MH. Requiring the equivalent power of the Wuskwatim G.S. now under construction, this customer might have been required to make capital contributions if a mechanism such as BC's Tariff #6 (see Section 6.2.2) had been available to MH.

3.2 Load History and Forecasts

3.2.1 Background to MH Filing

In large part, MH's most recent 2008 Load Forecast provides the background load history and projections for the various customer classes. The Load Forecast forms the basic starting point for MH's GSL 30-100 and GSL >100 subclass forecasts of industrial energy consumption within various industry classes.

These forecasts are further put into perspective by MH's 2005/06 metered domestic load, as illustrated in the following table (Schedule B-2, PCOSS-08):

Customer Class	**Load (GW.h)**	**Percentage of Total Load**
Residential	6,578	32%
GSS-ND	1,329	6%
GSS-D	2,038	10%
GSM	2,949	14%
GSL <30	1,612	8%
GSL 30-100	988	5%
GSL >100	5,202	25%
ARL	96	<1%
Total (Rounded)	**20,800**	**100%**

The segmented metered load corresponds to a load at generation of 22,899 GW.h, after taking into account distribution and transmission losses as well as weather adjustments. About 30% of the load arises from GSL 30-100 and GSL >100 customers, which total 34 in number.

These loads have grown significantly in the last two years and MH now forecasts base loads at generation of:

Total Domestic/Annual Increases			**GSL >30/Annual Increases**		**% of Total Increase**
	Load (GW.h)	Annual Change (GW.h)	Load (GW.h)	Annual Change (GW.h)	
2005/06	22,899	--	5,891	--	--
2006/07	23,318	418	5,950	59	14%
2007/08	23,568	250	6,059	109	44%
2008/09	24,085	517	6,380	321	62%
2009/10	25,108	1,023	3,787	407	40%
2010/11	25,891	783	7,225	438	56%
2011/12	26,554	683	7,591	366	54%
2012/13	27,137	583	7,883	292	50%
2013/14	27,483	346	7,947	62	18%
2014/15	27,811	328	8,009	60	18%
TOTAL		**4,931**		**2,114**	**43%**

Figure 3.1 which follows, illustrates 'Historic Load Forecast Trend for GSL>30' and the progression of GSL >30 load forecasts from 2000 to 2008, as plotted from Information Request 'MIPUG/MH I-3' (GSL 30-100 added to GSL >30). It is apparent that, prior to the 2005/06 forecast, MH was anticipating about 1,300 GW.h of GSL >30 growth to 2009/10 and little or no further growth to 2025-26.

However, Load Forecasts provided in 2005/06, 2006/07 and 2007/08 substantially increased the GSL >30 forecasts for loads after 2009/10, effectively projecting the addition of 1,500 GW.h of new load. This new load would presumably all come from the chemical and petroleum transport sectors.

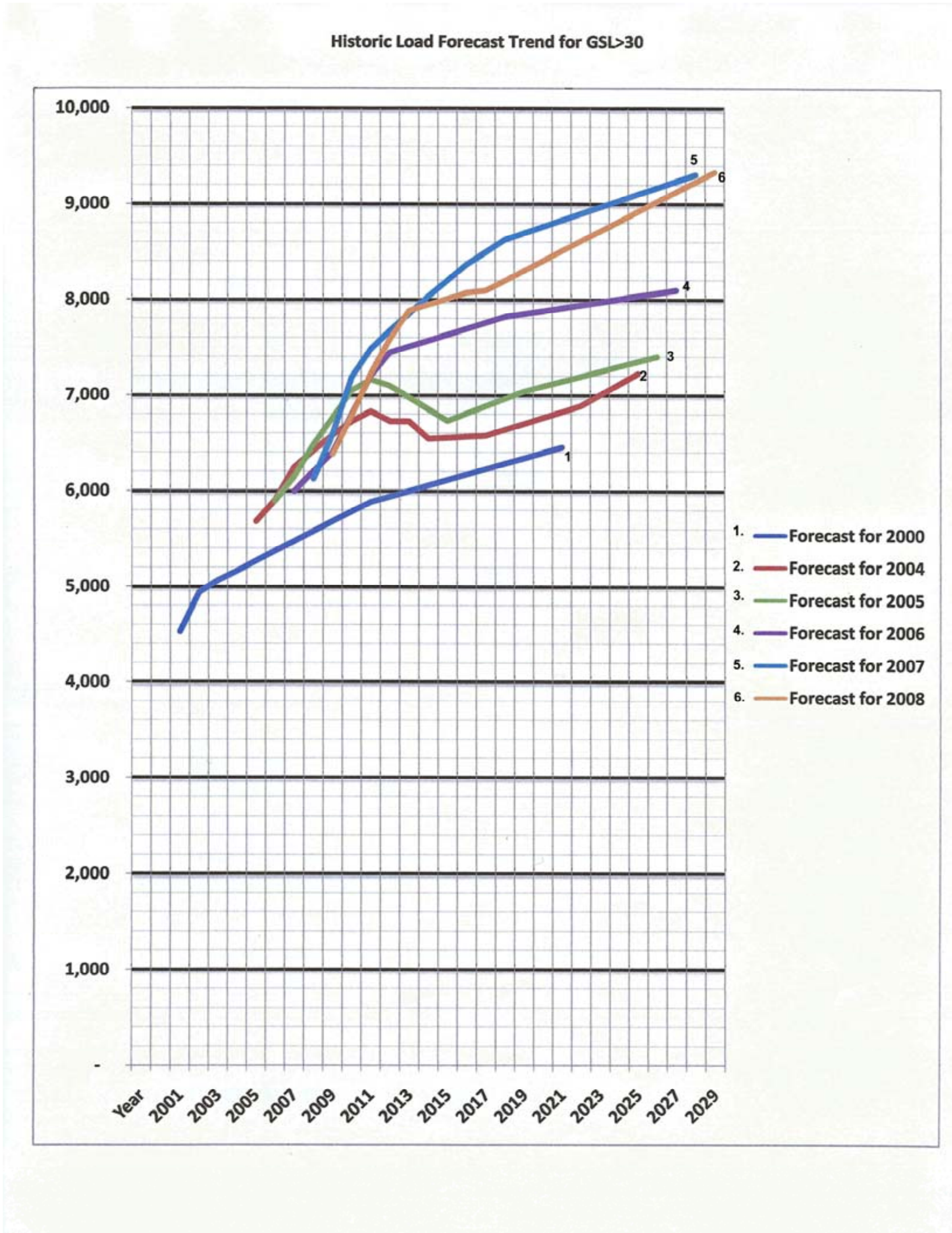
Extracts from the system load forecasts, shown in the table below, indicate that GSL >100 and GSL 30-100 projected energy usage for the years 2012 and 2018 have varied substantially over the progressive forecasts:

Forecast Dated	GSL >100 GW.h)		GSL 30-100 (GW.h)	
	2012	2018	2012	2018
2004	5,828	5,738	898	899
2005	5,469	6,334	1,627	1,627
2006	5,995	6,355	1,451	1,462
2007	6,195	7,123	1,479	1,503
2008	6,246	6,831	1,345	1,365

From examination of tables in MH's 2006 and 2007 Load Forecasts, it appears that MH anticipates that no more than 30% of future growth is to arise from industry sectors other than the chemical and petroleum transport sectors.

The chemical and petroleum transport sectors of MH's industrial customer class are expected to provide about 75% (1,300 GW.h) of the 1,700 GW.h total anticipated industrial load growth between 2006/07 and 2011/12. However, projected load growth in these sectors has not been expected to produce high levels of additional Manitoba employment.

FIGURE 3.1


Historic Load Forecast Trend for GSL>30
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
Year
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
1
2
3
4
5
6
1. Forecast for 2000
2. Forecast for 2004
3. Forecast for 2005
4. Forecast for 2006
5. Forecast for 2007
6. Forecast for 2008

MH's projection of industrial load growth does not provide for the potential arrival of new industrial companies in Manitoba. While this may, or may not, be an issue at this time, the arrival of a new energy intensive firm could impact now planned in-service dates for new generation and transmission.

Figure 3.2 which follows, illustrates the actual growth to 2007/08 and forecast growth to 2024/25 for residential class, GSL >30, GSL >100, the ten largest customers, and the four targeted customers. It is apparent that MH views the past eight years and the upcoming six years as a period of abnormal growth which will persist longer-term.

Figure 3.2 also provides information on the industry types that make up MH past/current/future energy consumption. It is clear that MH currently anticipates minimal growth in industry sectors other than the chemical and petroleum transport sectors.

MH's GSL >100 subclass grew by:

- 642 GW.h over six years (2000-2006) to 5,115 GW.h.
- 39 GW.h over two years (2006-2008) to 5,154 GW.h.

MH has now forecast that GSL >100 subclass will grow by a further 1,437 GW.h, by 2013 to 6,591 GW.h, and then grow by another 300 GW.h by 2018, to 6891 GW.h.

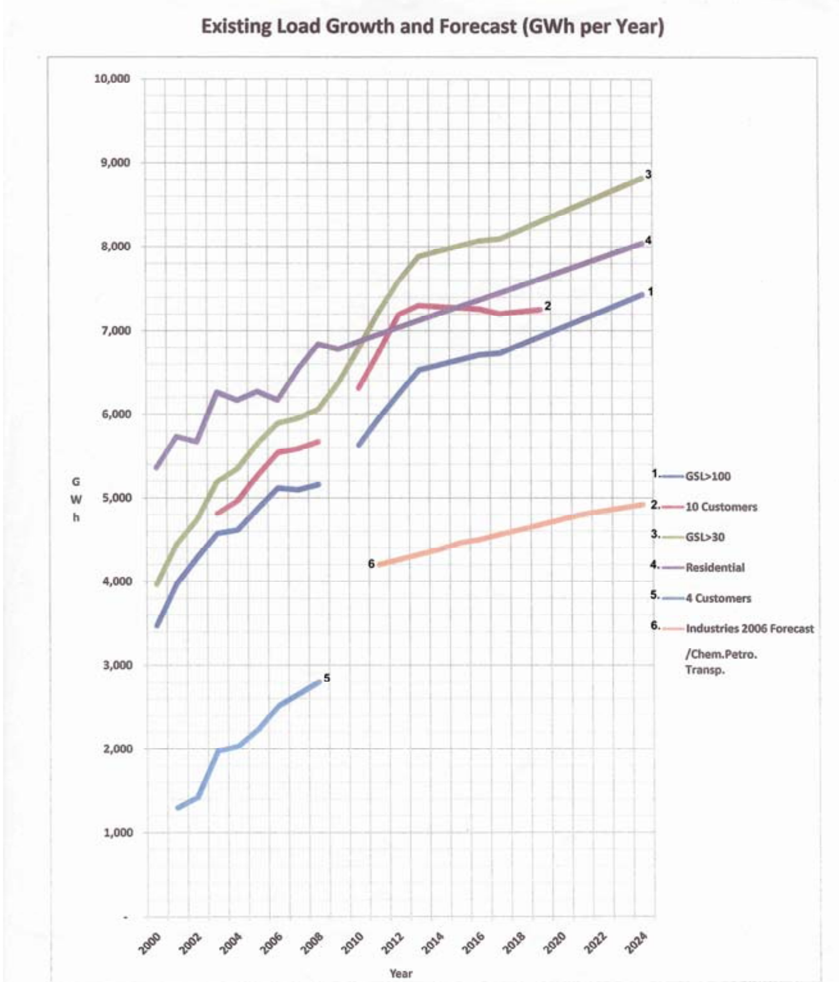


FIGURE 3.2

If the rather uneven load growth pattern of 110 GW.h/year for six years and 20 GW.h/year for two years (average of 80 GW.h/year over eight years) were projected forward, MH's current forecast growth of 290 GW.h/year or 1,437 GW.h (over the period 2008 to 2013) would be reduced to 400 GW.h., and GSL >100 consumption would be projected to be 5,554 GW.h in 2013 and 5,954 GW.h in 2018.

Given that almost 90% of forecast growth is expected to come from three customers, there appears to be a significant risk that MH's growth assumptions may not be achieved.

MH's GSL 30-100 subclass grew by:

- 284 GW.h over six years (2000-2006) to 776 GW.h.
- 129 GW.h over two years (2006-2008) to 905 GW.h.

MH is now forecasting that GSL 30-100 subclass will grow further by 448 GW.h by 2013 to 1,353 GW.h, and by a further 12 GW.h by 2018 to 1,365 GW.h. However, if the prior eight-year growth pattern of about 50 GW.h/year were projected forward, the GSL 30-100 subclass would be expected to grow by 250 GW.h to 1,155 GW.h in 2013 and by another 250 GW.h to 1,405 GW.h in 2018.

Back-out calculations (from MH's data) suggest that almost all of the growth in this subclass will come from one customer (i.e. 600-700 GW.h by 2013). As such, there is a high risk that the growth projected by MH may not be realized.

MH's largest ten energy consumers (9 GSL >100 and 1 GSL 30-100) consumed about 5,674 GW.h/year in 2008 (up by 860 GW.h from 4,814 GW.h in 2003). And, their energy usage is expected to grow by a further 1,625 GW.h by 2013 to 7,299 GW.h. After that, MH forecasts a decline of 75 GW.h by 2018, to 7,224 GW.h. Four of these customers consumed about 2,000 GW.h (about 30% of the 4,814 GW.h) in 2003, and about 2,800 GW.h (about 50% of the 5,674

GW.h) in 2008. This data implies a past growth rate for these four customers of 8%/year, as compared to the proposed CBEL growth allowance of 3%/year. It is also noteworthy that essentially all of the projected consumption growth in 2012 (of the top ten consumers) is projected to arise from the four EIIR targeted customers.

In Table 10 of the 2005/06 and 2006/07 Electric Load Forecasts, MH provided a series of five-year forecasts for industrial customers. These suggested growths (GW.h) are compared to 2007-08 Load Forecast, as follows (for the five-year intervals going forward) in the table below:

	Load Forecast	**Years 1-5 (GW.h)**	**Years 6-10 (GW.h)**	**Years 11-15 (GW.h)**	**Years 16-20 (GW.h)**
Chemical	(2005/06)	940	185	157	158
	(2006/07)	689	158	159	158
	(2007/08)	542	250	0	0
Petroleum Transport	(2005/06)	360	57	67	66
	(2006/07)	609	67	67	66
	(2007/08)	896	50	0	0
Primary Metals	(2005/06	9	(654)	68	(46)
	(2006/07)	144	2	(118)	(148)
	(2007/08	365	(75)	--	--
Pulp & Paper	(2005/06)	17	72	85	85
	(2006/07)	54	81	81	82
	(2007/08)	(19)	50	N/A	N/A

N/A - Not Available

MH appears to be scaling back its previous forecast levels of growth for the chemical industry, while raising its forecasts for the level of growth for the petroleum industry, and largely reversing an earlier expected decline in the primary metal industry.

MH's Load Forecast for GSL >30 customers is shown in Figure 3.1 through 2008. It appears that in its 2004 and 2005 forecasts, MH was anticipating a stagnation of industrial energy consumption after 2011, at about 5,500 GW.h for GSL >100 and about 7,000 GW.h for GSL >30.

In its 2006 forecast, MH raised these levels for 2011 onward by about 800-1,000 GW.h/year, presumably reflecting a projected continuation of the 300 GW.h/year actual growth rate experienced during 2004-2006.

MH's 2007 and 2008 forecasts further raised its 2013 onward forecasts by about 500 GW.h/year, despite minimal load growth from 2006 to 2008. This increase is difficult to rationalize, given the report of a lack of new industries, and given the potential impact of the new energy-intensive rate.

3.3 Growth Allowances

3.3.1 MH's Position

MH proposes that industrial customers in the GSL >30 class be allowed to establish a CBEL reflective of their highest 12 consecutive months of consumption over the three-year period ending March 31, 2008. MH further proposes that these customers be granted growth allowances as follows:

> *The CBEL would be adjusted upward by 3% annually to incorporate customer growth for the first five years. MH indicated the 3% growth allowance during the first five years was guaranteed regardless of whether or not the customer's load actually changes.*
>
> *Thereafter, annual CBEL growth would be limited to the lesser of the customer's actual increase in energy during the previous year in excess of the previous year's baseline, or 2% of previous year's CBEL, to a maximum baseline of 1,500 GW.h.*

To allow for above-average growth, with one year's advance notice, MH proposes customers be allowed a one-time step increase in their CBEL by 10% of the prior year's baseline. The new CBEL would be maintained at that level until the annual baseline growth allowance (as noted above) otherwise applied to the baseline equals the stepped baseline.

All energy in excess of the baseline plus applicable growth allowance in any one year, or in excess of the cumulative maximum baseline of 1500 GW.h would be charged at the new marginal rate.

3.3.2 Examination of Evidence

Industrial load forecasts for 2005/06 and 2006/07 suggest that if the EIIR were applied to all GSL >30 customers over a 20-year horizon, load growth allowances, as follows, would be required for complete exemption from EIIR:

Industry	**20 Year**	**10 Year**
Mining & Primary Metal	<0%/year	<0%/year
Food & Beverage	~1.5%/year	<2%/year
Pulp & Paper	~1.5%/year	1-2%/year
Chemical	~2.5%/year	4-5%/year
Petroleum Transport	2.5-3%/year	5-7%/year

Except for the chemical and petroleum transport industries, it appears that a growth allowance of 1.5 to2%/year would be sufficient to allow all other forecast growth to occur without incurring the new EIIR. MH's proposed growth allowance would appear to exempt all current customers (except where captured by the 1,500 GW.h cap) from the EIIR within 20 years.

As structured, the growth allowance serves to essentially preclude customers (in industry sectors other than chemical and petroleum export) from exposure to

EIIR. It also removes about 200 GW.h of chemical and petroleum industry growth from exposure to the EIIR by 2014. So, it appears that MH's proposed load growth allowances would exempt all but four to six customers from having to pay the EIIR. And, only three or four current customers would be affected on a significant and longer-term basis.

If the CBEL growth allowance were to be viewed as a contractual obligation (equivalent to an export contract), the accumulation of growth allowances (even if not used) would increase domestic load commitments and presumably reduce dependable energy available for export. As such, unused growth allowance could also trigger the advancement of new energy sources. The "value" (i.e. lost revenue to MH) of these growth allowances would escalate with rising export prices.

Industrial customers with unused growth allowances might be well inclined to put off energy efficiency/conservation measures where there is no price incentive. This runs counter to MH's suggestion that the EIIR would offer modest price signals to customers as they approach their CBEL.

If the CBEL growth allowances were limited to off-peak energy only (not unlike the guaranteed make-up energy in the Curtailable Rate Program, CRP), all customer growth during the on-peak periods would pay the EIIR. This would encourage load shifting to the off-peak (night time and weekends), leaving MH with higher value energy to support 5x16 (i.e. 5 days/week and 16 hours/day) export contracts, and could also relieve on-peak generation capacity constraints.

3.4 Hard Cap of 1,500 GW.h

3.4.1 MH's Position

- A limit on industry growth is essential to protect MH's domestic and export revenue base and avoid additional rate increases;
- Unlimited growth by energy intensive industry will require advancement of new energy resource projects; and
- A limit on individual customer size reduces risks and potential revenue shortfalls.

3.4.2 Examination of Evidence

Early in 2008, MH became fully aware of the potential implications of a 1,500 GW.h hard cap on its largest customer's latest expansion, which is coming on-stream. Furthermore, MH's approach was intended to level the playing field for two large chemical sector customers; with both parties to be provided the same GW.h growth opportunity at heritage rates.

MH's hard cap of 1,500 GW.h/year has the apparent effect of:

- Establishing a maximum customer size;
- Limiting an individual customer's growth increment that might be heritage priced to about 300 GW.h.;
- Ensuring that its largest customer's most recent load addition will be entirely subject to EIIR; and
- Capturing an additional 200-300 GW.h/year in energy within the EIIR (about $6 million/year of revenue) from one customer.

The hard cap of energy of 1,500 GW.h is not consistent with MH's evidence that generation capacity and other constraints limit MH's 5x16 peak exports, but generally not off-peak exports. 10% of the proposed cap (or 150 GW.h load increase) has different impacts for different load shapes:

- 5x8 load requires 86 MW of generation capacity;
- 5x16 load requires 43 MW of generation capacity;
- 7x24 load requires 20 MW of generation capacity; and
- an off-peak (only) load addition would not require any new generation capacity.

It may be more appropriate to impose a capacity cap (e.g. 10 or 20 MW) on accumulated growth above current demand, with all of the peak energy usage above that level being subject to the EIIR. This could shield up to 80 GW.h of peak loads on an annual basis if it replaced growth and DSM allowances in the EIIR program design.

MH's argument for a hard cap of 1,500 GW.h appears to be premised on the notion that large new loads have greater impacts than an aggregation of many small new loads. The reality is that ten new loads of 50 GW.h each could provide the same pressure for new generation (or lost export revenue) as one new load of 500 GW.h. However, the current EIIR proposal would achieve substantially more revenue from the larger load expansion than if the load expansion came from ten customers.

3.4.3 MH's EIIR

If revenue-neutral, the EIIR would reportedly achieve the same revenues as gained by MH under current export contracts for the on-peak portion of the customer's load growth. And, based on the evidence, this appears to be the case. However, MH is proposing to also collect the same rate for the off-peak portion of the customer's load growth.

The Board understands that MH's largest customer is currently using about 1,500 GW.h of energy at a 200 MW demand level. At current rates, this results in an average cost of energy of 3.3¢/kW.h. If that customer increased the demand to 250 MW and used 2,200 GW.h of energy, the application of the EIIR to the growth would increase the average cost of energy to 3.9¢/kW.h.

Further, if that customer increased the total demand to 500 MW and used 4,000 GW.h of energy, the EIIR application would result in an average cost of energy of 4.7¢/kW.h to that customer.

In contrast, if MH were to sell the peak portion of consumption under an existing 500 MW 5x16 contract, and then sell the off-peak portion into the MISO market at 2.25¢/kW.h, the average revenue achieved by MH would be about 3.9¢/kW.h. This illustrates that a 50 MW increase in load would, under the EIIR, result in a break even for MH. Above that level and going to a 500 MW Northern States Power Company (NSP)/ Xcel Energy Inc. (Xcel) contract level, MH would achieve significantly more revenue from a large industrial customer under the EIIR than MH gains in the export contract process.

As such, the EIIR should be significantly reduced or applied only to the peak portion of load growth.

3.5 DSM and Energy-Efficient Solutions

3.5.1 MH's Position

MH contends that customers should get full credit for all past DSM measures in defining the CBEL on the basis of:

- Historic loads would have been higher, but for DSM;
- Reinforcing the perceived value of DSM programs;

- DSM reductions having undiminished ongoing value without the need for re-validation; and
- Rewarding customers who actively pursued DSM activities.

3.5.2 Examination of Evidence

Theoretically, DSM activities since 1992 have reduced industrial loads by 336 GW.h, though MH has not re-validated the initial assessment. Interveners have questioned MH's claims of DSM energy savings persisting at a constant level into the future, particularly those undertaken prior to 2000. In the absence of substantive evidence, MH's assertion that the DSM remains at least 90% effective cannot be confirmed.

The proposed treatment of past DSM, while not according similar treatment to currently planned and future DSM, may suggest a degree of customer load vintaging, with older longer-term industrial customers gaining more than others.

It is not entirely clear from the evidence whether customers who undertook DSM in the past were inadequately compensated (either by energy bill reductions or DSM subsidies). However, it is possible that more recent DSM activities (as distinct from Power Smart) may not have been fully amortized by the companies. As such, a case could be made for a time scale approach to DSM discounting over the last ten years.

3.6 Threshold of 100 GW.h/year

3.6.1 MH's Position

MH's position is that the ten largest customers account for more than 90% of GSL >30 industrial energy consumption, and that there is insufficient potential

EIIR revenue from the other 24 customers to cover the additional administration costs of extending the EIIR to include them. Therefore, by setting the threshold CBEL at 100 GW.h, MH claims to avoid the administrative complexities and associated costs of expanding the application of the rate to these 24 existing customers.

In MH's proposal, the threshold of 100 GW.h is also to be applied to new customers establishing industry in Manitoba. Yet, in the last ten years there has been only one new customer using more than 100 GW.h; future prospects may not be any more significant.

3.6.2 Examination of Evidence

Evidence as provided suggests that MH would see little, if any, financial gain in extending the EIIR to the 25 smaller customers included in GSL >30, unless one or more of these were to fully avail themselves of their low rate-growth opportunities. It is noteworthy that the average individual consumption levels of these other GSL >30 customers is only about 10 to 15 GW.h. Substantial growth opportunities will be available at heritage rates for these existing customers, if MH's proposal is accepted.

Such a situation would not encourage DSM investments; rather, it might enable energy intensive growth, albeit at a lower customer size level.

Theoretically, the total load from these exempt customers could grow from about 400 GW.h/year to about 3,000 GW.h/year without triggering the EIIR. However, at a more realistic level, 5 to 10 customers (existing and new) choosing to optimize their growth opportunities could add 400 to 800 GW.h to MH's annual industrial load at heritage prices pursuant to MH's current proposal.

It would also seem that the 100 GW.h/year threshold would encourage outsourcing to smaller companies; and encourage single-shift, on-peak operations, as opposed to multi-shift peak and off-peak operations, thereby requiring greater generation capacity.

3.7 Affiliations

3.7.1 MH's Position

MH's position calls for the aggregation of consumptions (from all affiliated companies currently using more than 100 GW.h/year) in determining customer CBELs. While there is no current affiliations that would be captured pursuant to MH's proposal, the utility anticipates that load desegregation could be employed at some time to reduce loads subject to EIIR, and thus, proposes the provision.

It is MH's intention to monitor customer loads/ownership with a view to prevent such disaggregating, where it would reduce the potential load subject to EIIR.

3.7.2 Examination of Evidence

Companies expanding through the acquisition of existing Manitoba companies will, under MH's proposal, have their baseline load increased by the amount of the acquired company's baseline load.

While the evidence (as provided) suggests no potential affiliations of concern, there remains the possibility of "gaming" the approach by new players or ownership changes. "Gaming" might involve load-splitting between affiliates, whereby a rapidly growing company would take advantage of static consumption or conservation measures of an affiliate to grow in consumption beyond the proposed 3% annual growth rate, without facing the marginal cost rate.

MH has not quantified the potential economic impact of “gaming.” Initially, with only four EIIR-affected customers under MH’s proposal, the potential for “gaming” is limited to perhaps one customer whose growth allowance is currently precluded. If most GSL >30 customers were subject to the new rate, there would be a greater probability of load splitting activities.

3.8 Price of Second-Tier Energy

3.8.1 MH’s Position

The proxy rate to serve as the second-tier rate in its EIIR proposal is, as defined by MH, reflective of the average value of firm contracted export sales in 2006/07 and 2007/08. The sales involved the delivery of 5x16 peak energy into the U.S. (MISO area) market. It is MH’s intent to apply this proxy rate (5.53¢/kW.h) to all non-exempted domestic load growth in peak and off-peak periods.

While MH acknowledged it had considered proposing a proxy rate based on the average value of all export sales, it reported its rejection of that option. It appears to be MH’s position that all energy (on-peak and off-peak) diverted from domestic industry usage can be shaped and formed into 5x16 peak export sales. Because the export price (5.53¢/kW.h) includes a demand component (not defined), MH has chosen to back-out 0.74¢/kW.h (based on 730 hours/month and a 100% load factor) from the export price to arrive at its proposed second tier energy rate for the EIIR.

3.8.2 Examination of Evidence

MH’s proxy price is intended to supplant the need to publicly define the utility’s marginal cost (MC) as it relates to:

- Cost of future hydraulic generation and transmission;
- Cost of alternate energy supplies (wind/thermal/imports); and
- Forecast exports and export prices.

If transparency is to be reduced, there is a greater need to select a clearly defined and accurate value for a proxy, one clearly based on only the peak export price. It is necessary to establish terms and conditions, shape and form, committed energy profiles, as well as energy and demand price components of the export product, so as to ensure the compatibility with industrial loads.

If MH cannot comply with the above, perhaps for reasons of confidentiality, an alternate proxy, one reflecting all export sales prices, might be more acceptable. MH has supplied data illustrating the make-up of its peak and off-peak export sales for 2005/06, 2006/07, and 2007/08, in support of its selected proxy price.

These documents differ somewhat on the calculation of the proxy price (5.416¢/kW.h instead of 5.527¢/kW.h), and MH attributes this to timing issues. While merchant trading and hedging have been excluded, MH acknowledged that both total energy sales and revenues may be overstated due to non-deliveries/resales/buy-backs, though claiming that the average revenue prices would not be materially different.

A bigger issue is whether the proxy price should, instead, be based on the average of all export sales (7x24), in order to conform more closely to domestic industry consumption. That would suggest a proxy of 4.97¢/kW.h (that being the weighted average of firm and opportunity sales).

The proposed proxy export price of 5.53¢/kW.h may actually understate the value of 5x16 energy, which was just above 6¢/kW.h in the last two years;

however, it is substantially above both the average off-peak price of less than 3¢/kW.h and the average price of about 5¢/kW.h for all export energy.

The proposed use of the peak-only proxy price for all industrial energy growth raises questions about:

- Hydraulic energy supply resources; is there sufficient reservoir storage to accommodate all load-shaping needs of this EIIR, wind, etc.?
- Generation capacity; should thermal generation and imports be excluded when defining capacity limits?
- Transmission tie-line capacity; should non-firm, short-notice transmission capacity be considered when scheduling firm export sales?
- Export market availability; is the assumption of unlimited 5x16 market take-up consistent with unused 5x16 tie-line capacity during the spring and fall months?

For each of the above questions, constraints appear to be likely and, in aggregate, significant. On balance, it would appear that new energy from industrial load reductions will not have unfettered access to peak market prices.
If the use of a firm 5x16 proxy price is to be confirmed, it will be necessary to assess the variable value of this energy.

In high-flow years, MH:

- Cannot increase summer 5x16 contract exports that are typically at the limit of scheduled tie-line capacity; industrial usage reductions can only add to low-end priced off-peak exports.

- Could increase winter 5x16 contract exports that are typically constrained by generation capacity and not by tie-line limits; reduced industrial usage during peak would go to peak exports/off-peak to off-peak.

- Cannot increase spring and fall 5x16 contract exports, as these appear to be limited by market receptivity/significant off-peak sales suggest energy is available/neither generation capacity or tie-line limits appear to be in play/lower industrial usage can only add to off-peak exports.

In average-flow years, MH:

- Presumably looks to maximize 5x16 summer contract exports at 700-750 GW.h/month over four months (3,000 GW.h), which would appear to leave about 4,000 GW.h for the remaining nine months at 450 GW.h/month (with 50% under contract/50% as opportunity sales). Industrial load reduction would only have off-peak value in the summer.

- Could use industrial load reduction in the winter to achieve peak values in 5x16 periods, and might achieve on-peak prices for the off-peak reductions.

- Could use industrial load reductions in the spring and fall to achieve peak value in 5x16 periods, but off-peak energy might economically be moved to winter off-peak.

In low-flow years, MH:

- Looks to apply about 3,000 GW.h of available energy to 5x16 exports. About 2,000 GW.h would go to satisfy long-term contract needs @ 170 GW.h/month, leaving an additional 250 GW.h/month for four summer months. Industrial load reductions would flow to meeting remaining winter peak needs, and all of this energy might thus achieve on-peak prices.

Overall, MH expects that all industrial load reductions could command 5x16 peak values, but this claim can only be entirely correct about one-third of the time. On balance, only 5x16 usage reduction may lead to additional on-peak prices, off-peak reductions are likely to achieve off-peak prices.

The proxy price should either reflect all of MH's exports (on-peak and off-peak) or peak prices should only apply to peak-period reductions, with off-peak prices applying to off-peak reductions.

MH's proxy price of 5.53¢/kW.h reflects both energy and demand values in the export market. To set the second tier energy rate, MH has backed out a demand component (already being paid for by the customer) of 0.74¢/kW.h (which is derived by dividing the monthly $5.40/kVA for GSL >100 by the total 730 hours in a month). That assumes a load factor of 100%.

However, the average class load factor is 83%, and this suggests 600 hours/month be divided into $5.40/kVA to result in a 0.90¢/kW.h adjustment, and this would lead to a second-tier energy charge of 4.63¢/kW.h, rather than the 4.79¢/kW.h by MH's calculation.

It seems clear that the second tier energy charge should be reduced to:

- 5.53-0.90 = 4.63¢/kW.h if applied only to 5x16 energy growth.

or

- 4.97-0.90 = 4.07¢/kW.h if applied to both peak and off-peak energy growth.

Note: The value of capacity in MH's 5x16 export sales could be as high as 1.50¢/kW.h, to reflect a 47% load factor related to 5x16 energy.

Export data filed in support of the proxy covered three high-flow years of 2005/06, 2006/07 and 2007/08; similar data was not provided/available for low or medium-flow years.

Information Request PUB/MH I-12(b) provided MH's response to a Board Directive for an in-depth analysis of the on-peak and off-peak MISO export market, and offered only limited insight into the potential variability of MH's export sale prices. It would have been more useful if the analysis provided, in current dollars, data for a longer time-period (e.g., 1999 to 2008), and if the off-peak values had been weighted to reflect the preponderance of night-time (7x8) hours, as compared to weekend (2x16) hours. That approach would have yielded a significantly lower off-peak value (i.e. $27.80/MW.h instead of $30.11/MW.h).

3.9 Cost of Service Treatment

3.9.1 MH's Position

MH suggested that the additional domestic revenue from EIIR should be treated as a separate line item (similar to exports) in the Cost of Service Study (COSS). As there are no incremental embedded costs associated with the EIIR energy, MH would allocate a cost equal to the revenue yielding a Revenue to Cost Ratio (RCR) of 100%.

The approach is intended to avoid a further distortion in RCRs for the GSL 30-100 and GSL >100 subclasses, which already have RCRs in the range of 105 to 110%. This would avoid even greater RCR disparities and retain integrity for the COSS process.

Going further, MH would not expect to allocate a share of net export revenues to the EIIR line item.

3.9.2 Examination of Evidence

MH's COSS treatment suggestion seems to infer that there are no embedded cost allocations in the current COSS for the export class. The most recent Prospective Cost of Service Study, PCOSS, directly assigns variable costs and allocates embedded costs to the export class, on the basis of relative energy consumption. Any remaining net revenue (profit) is shared by all domestic consumers, that in proportion to their embedded cost (in the determination of RCRs).

When, in the COSS 08 model complying with Order 117/06, all customer classes (domestic and export) were allocated bulk power Generation and Transmission (G&T) costs on the basis of energy consumption, the pre-export credit RCRs indicates that the domestic classes do not currently cover their embedded costs. The respective RCRs and an estimated revenue shortfall are:

Rate Class	RCR	Revenue Short fall ($ millions)
GSL >100	95%	$11
GSL 30-100	90%	$ 4
GSL <30	77%	$20

GSM	88%	$20
GSS	89%	$26
Residential	85%	$80
		$161

This suggests that the EIIR might move GSL >100 and GSL 30-100 rates and RCRs above fully embedded cost-recovery levels. Currently, all domestic customers are allocated similar bulk energy G&T costs when calculated at generation. And, at the meter, a modest difference relating primarily to distribution losses comes into play.

The proposed new EIIR is not really premised on equal bulk power costs for all domestic customers. Rather it looks to incorporate risk and benefit elements into the bulk power rate determination.

This, in effect, is a form of vintaging. In moving toward marginal cost, MC, for industry (but not for residential and commercial classes), MH is implying that all current load is entitled to embedded cost (heritage) rates, and that all growth for residential and commercial will also continue to enjoy heritage rates. Only industrial load growth will see a degree of MC pricing, and, as is now the case, exports may or may not pay full MC.

The proposed EIIR would introduce MC to the rate setting process, within an embedded COSS. The only significant costs obviously attributable to the GSL >30 industrial customers are G&T bulk energy costs, which are largely allocated on an energy consumption basis. Generation costs that are 100% energy-related account for about 80% of all bulk energy costs, and largely determine the G&T costs that flow to each of the domestic classes and to the export class.

This suggests inter-class subsidies, which tacitly exist in most jurisdictions employing COSS and a RCR Zone of Reasonableness. If a rate subsidy continues to be justifiable for residential customers (because they live in Manitoba), it would seem that commercial and industrial customers in Manitoba should also enjoy some level of "The Manitoba Advantage." Any employment created in Manitoba by domestic load is very likely to be positive relative to that achieved by exports.

In that context, it would not be appropriate to have the EIIR achieve higher revenues than could be secured on the export market. It might be better to under-achieve than to exceed revenue neutrality.

There have been suggestions that EIIR levels higher than those proposed by MH would promote greater Green House Gas (GHG) emission reductions in the MISO region. However, it is difficult to see how a 1,500 GW.h customer located in Minnesota or North Dakota using MH exported energy would have a lesser carbon footprint than that same customer located in Manitoba.

Another alternate approach might be to declare that industrial sector customers pay similar to contract rates and enjoy similar market access to that which MH's export contract customers experience.

To look to a MC COSS methodology as a resolution to this issue is certainly premature. As evidenced in the 2008 GRA, there is the oft-time stated objective that every customer should pay MC for energy; but MH has replied that it does not plan to apply this MC to residential and commercial customer rates.

EIIR is a fundamental departure from an embedded cost rate-setting. It can only be justified on the basis that MH's MC of energy is increasing as the need for additional power supplies is increasingly being met from higher-priced resources (new hydraulic generation, existing but idle natural gas thermal generation, imports, and/or foregone exports). It is apparent that new generation and transmission, and distribution for that matter, involve capital expenditures many times higher than the costs embedded through past expansions, enhancements and renovations.

Because MH is in the energy export business (and in an increasingly substantial way), as well as being the dominant domestic energy supplier, it has become increasingly difficult to determine what power resource acquisitions are triggered by export commitments as opposed to domestic need. As such, supply deferrals are not a reliable indicator of MC. Instead, MH has chosen a historical price of export energy proxy to define MC.

While (with its EIIR proposal) MH is moving toward charging MC to industry, there is no verified commitment to ensuring that new export contracts will pay MC for hydraulic generation being advanced to service their load. With RCM/TREE lobbying for a higher EIIR (reflecting Wuskwatim Generating Station, GS costs, which are about 50% higher than prices MH is achieving from its largest current export contract), there is a need to confirm MH's policies respecting export energy pricing.

It seems inappropriate for MH to support a higher priced EIIR without committing to similarly-priced export prices.

When new large-scale hydraulic generation is being advanced to serve new export contracts, the contract prices should reflect MC of the new facility. The use of blended (historical and new) average system supply (G&T) costs is no longer appropriate.

Somehow, this comes full circle. If MH wishes to charge industry for costs higher than embedded, MH must disclose the pending (as well as existing) export contract prices to the Board.

4.0 Power Supply

4.1 Power Resource Plan (MH Exhibit #19)

4.1.1 MH's Position on Dependable Energy

Despite the strong industrial growth and above average residential growth in electricity consumption, the available dependable energy (as defined by MH's latest Power Resource Plan) is sufficient to meet currently-projected domestic loads and firm export contracts until about 2012. This is possible through the use of wind, the Brandon Coal Generation Station, and scheduled or opportunity imports (that might displace 3,460 GW.h of natural gas generation).

The addition of Wuskwatim G.S. (in 2012), another 300 MW of wind (in 2013), and 43 MW from increased Pointe du Bois output in 2017 are expected to meet the dependable supply requirements to domestic customers and the NSP/Xcel Contract Extension until about 2017/18.

Beyond 2017/18, the addition of Bipole III and Keeyask G.S. should adequately cover the pending Minnesota Power 250MW contract until about 2017/18; but additional energy resources, presumably Conawapa G.S., will come on-line by 2022 to meet the needs of the additional Wisconsin Public Service 500MW pending contract.

Through the Power Resource horizon, MH will be looking to annually import a minimum of 3,000 to 5,000 GW.h of energy plus an additional 3,460 GW.h to avoid having to employ MH's own higher-priced natural gas generation.

4.1.2 MH's Position on Generation Capacity

From 1992, when Limestone G.S. fully came on-line, to 2007/08, MH neither had to utilize its thermal resource capacity nor its diversity imports to meet peak base domestic, and its long-term export contract, commitments. Thermal energy and imports were only required to support opportunity exports and system reserve requirements.

Even with Wuskwatim G.S., Kelsey G.S. upgrade, Brandon Coal G.S. and DSM, MH expects to employ upwards of 200 MW of imports to meet winter domestic and long-term firm contract commitments and reserves until 2022, when Conawapa G.S. (assuming Keeyask & Bipole III are already in place) comes on-line. With Conawapa, MH's generation capacity would be sufficient to extend the now pending level of contract sales until about 2035/36.

MH favours advancing new generation capacity to capture additional exports. On a strictly domestic load basis, new generation is not yet required. While the most cost-effective hydraulic generation is already in place and the next level of higher-cost generation is scheduled, MH still does have several potential generating station sites on the Nelson River (1,300 MW), on the Burntwood River (600 MW), and on the Upper Churchill River (250 MW), though these may not all be physically or environmentally feasible.

However, if MH's exports do evolve into a higher-value "green energy" commodity, most of these sites may become economically viable.

4.1.3 Examination of Evidence

In the MH 2008/09 Power Resource Plan, the imports employed to define dependable flow are part of energy diversity agreements. Apparently, imports allow MH to purchase winter energy on a guaranteed supply basis, and primarily during off-peak periods at market prices, while also allowing a counter-party to purchase a comparable amount of summer energy on a guaranteed supply basis, primarily during the off-peak periods at market prices.

These agreements are intended to achieve a balance, either on an annual or several year time-frame.

It is not readily apparent whether or not MH's export forecasts in the Power Resource Plan treat the diversity paybacks as potentially firm export commitments. These payback requirements could have serious impacts going into a drought year (eg. 2003/04).

Despite the ongoing need for scheduled imports, in higher flow years MH tends to operate as a strictly hydraulic energy purveyor. Generation capacities are viewed as being constrained using only hydraulic assets. While this implies that all exports utilize lower cost hydraulic generation, the reality may be that in average or lower flow years some exports are only marginally profitable, though they do contribute to, and inflate, reported average export prices.

MH's planning approach looks to advance new hydraulic generation well ahead of the domestic load requirement. This is expected to produce additional revenues with (perhaps) relatively modest cost increases. However, export prices tend to be lower initially after new generation comes on stream and may be insufficient to fully cover early year finance and depreciation charges. Deferral of New Generation could, at times, be a better strategy when demand and pricing remain uncertain.

4.2 Power Supply

4.2.1 MH's Position

The following tables represent MH's dependable energy resources and system-firm winter capacity, matched up against MH's domestic load and firm export contract requirements. This abridged data is drawn from MH's 2008 Power Resource Plan and illustrates the close tracking of supply and demand.

The tables reflect MH's minimum export capability and define MH's ability to enter into export contracts. In almost all years, MH will be able to export considerably more energy on the basis of short-term sales.

4.2.2 Examination of Evidence

MH's domestic load is forecast to grow from about 25,000 GW.h (4,500 MW) in 2009/10 to 31,000 GW.h (5,500 MW) in 2024/25. Of the forecast 6,000 GW.h (1,000 MW) increase, GSL >30 industries are expected to account for 2,100 GW.h (300 MW). The GSL >30 share of the total load is forecast to remain at about 30%, as it was in 2005/06.

By 2024/25, MH's export contracts are projected to have added about 2,600 GW.h (5x16 sales) and 700 MW to 2009/10 sales levels. The total increase to 2024/25 in projected firm load is 8,600 GW.h (1,700 MW + 120 MW reserve or 1,820 MW).

MH's proposed new hydraulic generation is projected to increase dependable hydraulic energy output by 8,700 GW.h (2,200 MW).

MH has reported that industrial load growth puts greater pressure for new G&T investments than other consumption increases. An examination of the forecast dependable energy situation over the next 15 years to 2024/25 suggests that MH's industrial load will add 2,100 GW.h (300 MW).

In the absence of any GSL >30 customer load growth, MH would still have had 3,700 GW.h (700 MW) of growth in the residential and commercial sectors. As such, with the pending export contracts as a given, Keeyask G.S. might be deferred by one or two years.

Dependable Energy at Generation (GW.h)

		2009/ 2010	2012/ 2013	2015/ 2016	2018/ 2019	2021/ 2022	2024/ 2025	2027/ 2028
Power Resources								
Hydro	Existing G.S.(s)	21,110	21,060	20,920	20,870	20,830	20,810	20,550
	Wuskwatim G.S.	--	1,250	1,250	1,250	1,250	1,250	1,250
	Bipole III	--			243	258	162	162
	Keeyask G.S.	--			1,371	2,900	2,900	2,900
	Conawapa G.S.	--					4,550	4,550
	Point du Bois G.S.	--			150	150	150	150
		21,110	**22,310**	**22,170**	**23,893**	**25,388**	**29,822**	**29,562**
Thermal	Brandon Coal	837	837	837	837	--	--	--
	Selkirk Gas	1,060	1,060	1,060	1,060	1,060	1,060	1,060
	Brandon Gas	2,400	2,400	2,400	2,400	2,400	2,400	2,400
		4,297	4,297	4,297	4,297	3,460	3,460	3,460
Other	Wind	320	1,069	1,229	1,229	1,229	1,299	1,299
	DSM	317	616	823	870	958	994	1,070
		637	1,685	2,052	2,099	2,187	2,223	2,299
Imports	NSP/Xcel etc.	2,796	2,796	1,063	800	800	800	1,575
	NSP/Xcel Extension	--		2,060	2,468	2,468	2,753	
	WPS 500/MP 250	--			383	1,534	2,301	2,301
		2,796	2,796	3,123	3,651	4,802	5,854	3,876
	Total Power Resources	**28,841**	**31,089**	**31,642**	**33,939**	**35,838**	**41,144**	**39,267**
Domestic Load								
	including GSL >30	25,109	27,137	28,199	29,055	30,073	30,998	31,998
	excluding GSL >30	18,322	19,254	20,047	20,755	21,463	22,078	22,768
	GSL >30	6,787	7,883	8,072	8,300	8,610	8,920	9,230
	Targeted 4 Customers	3,330	4,100	4,100	4,100			
Exports								
	NSP/Xcel/etc.	3,626	3,259	353	145	145	145	145
	NSP/Xcel Extension			1,920	2,062	2,062	2,636	--
	WPS 500/MP 250				574	2,296	3,444	3,444
		3,626	3,259	2,273	2,781	4,503	6,225	3,589
Total Demand		**28,735**	**30,396**	**30,392**	**31,836**	**34,576**	**37,223**	**35,587**

System Firm Winter Capacity (MW)

		2009/10	2012/13	2015/16	2018/19	2021/22	2024/25	2027/28
Power Resources								
Hydro	Existing G.S.(s)	4,900	4,900	4,900	4,900	4,900	4,900	4,900
	Wuskwatim G.S.		200	200	200	200	200	200
	Bipole III				89	79	10	10
	Keeyask G.S.				93	648	648	648
	Conawapa G.S.						1,294	1,294
	Point du Bois G.S./Kelsey				118	118	118	118
		4,900	5,100	5,100	5,400	5,945	7,170	7,170
Thermal	Brandon Coal	105	105	105	105			
	Selkirk Gas	132	132	132	132	132	132	132
	Brandon Gas	298	298	298	298	298	298	298
		535	535	535	535	430	430	430
Other	Wind							
	DSM	46	109	153	189	209	222	244
Imports	NSP/Xcel etc.	616	616					
	NSP/Xcel Extension			385	385	385	385	--
	WPS 500/MP 250	--						
Total Capacity		**6,097**	**6,435**	**6,248**	**6,509**	**6,975**	**8,207**	**7,844**
Peak Demand								
	Domestic Load	4,515	4,838	4,972	5,122	5,302	5,481	5,660
	excluding GSL >30	3,515	*	*	*	*	4,200	*
	GSL >30	1,000	1,100	1,050	1,200	1,250	1,300	1,350
	Targeted 4 Customers	360	*	*	*	*	*	*
Exports								
	NSP/Xcel/etc.	693	605					
	NSP/Xcel Extension			413	413	413	550	
	WPS 500/MP 250				165	550	825	825
		693	605	413	578	963	1,375	825
Total Load		5,208	5,443	5,384	5,700	6,265	6,856	6,485
Reserve		462	493	532	546	565	585	650
Total Peak Demand		**5,670**	**5,936**	**5,916**	**6,246**	**6,830**	**7,441**	**7,135**

*** Limited Information**

4.3 Power Sales/Revenues

4.3.1 MH's Position

In the near term, MH is looking at the following power supply commitments:

- Existing 500 MW Xcel Contract actually commits MH to reserve 550 MW (500 MW + 10%) until 2014/15;
- Proposed 375/500 MW Xcel Contract actually commits MH to reserve 413 MW (375 + 10%) until 2022/23 and then 550 MW (500 + 10%) until 2024/25;
- Proposed 500 MW WPS Contract actually commits MH to reserve 550 MW (500 + 10%) from 2019/20 to 2030/31; and
- Proposed 250 MW MP Contract actually commits MH to reserve 275 MW (250 + 10%) from 2022/23 to 2034/35.

While MH contends that these contracts supply an "inferior" energy product to that available to domestic industry, the Utility is not willing to "go public" with contract terms and conditions that may support that position.

In the absence of contract specifics, it can be inferred these contracts have the following potential energy requirements:

Contract		+ 10% Reserve	Min. 5x16 Delivery	Total Energy On-Call (7x24)
Existing Xcel	500 MW	550 MW	2,080 GW.h	4,380 GW.h
Pending Extension of Xcel	375 MW 500 MW	413 MW 550 MW	1,560 GW.h 2,080 GW.h	3,285 GW.h 4,380 GW.h
Pending WPS	500 MW	550 MW	2,080 GW.h	4,380 GW.h
Pending MP	250 MW	275 MW	1,040 GW.h	2,190 GW.h

MH has indicated that access to energy above the minimum 5x16 delivery is at MH's discretion. However, the right of first refusal at market prices could exist.

As MH does not own the transmission rights that facilitate these contracts, there may be some limitations on MH's ability to move energy into the MISO market. None of this precludes the export contract customer from buying the same off-peak power directly from the MISO market.

MH does also have some ability to deliver energy into Ontario and Saskatchewan, but not at the same scale as into the U.S.

4.3.2 Examination of Evidence

a) Building for Export

MH is in the process of committing to three export sales contracts that will require energy deliveries from 2016 to 2032. These overlap to a significant extent and, in 2022, will add 1,375 MW firm demand (1,250 MW + 10%) to a base domestic load of 5,362 MW (plus reserves). This equates to a minimum export 5x16 firm energy requirement of 6,000 GW.h on top of base domestic load of 30,000

GW.h. It may also to another 7,000 GW.h of off-peak energy sales if export contract options are exercised.

This level of export commitment requires that Bipole III, Keeyask G.S., and Conawapa G.S. be in place. The previously-identified project costs were:

Capital Project ($ billions)	
Bipole III -	$ 2.3
Keeyask G.S. -	$ 3.7
Conawapa G.S. -	$ 5.0
	$11.0

These estimated costs have not been updated to reflect the very substantial construction cost escalations predicted at the 2008 GRA. However, MH recently suggested that Keeyask G.S. costs could now reach $4.6 billion while Conawapa G.S. could cost $6.3 billion. The cost estimates for earlier in-service projects, such as Wuskwatim G.S., at $1.7 billion, Pointe du Bois G.S., at $0.8 billion, and Kelsey G.S. at $0.2 billion have also not been updated.

Prior to finalizing the three new export contracts, it is anticipated that MH will update all major project cost expectations. The cost for the Bipole III/Keeyask/Conawapa group alone could well rise to $14 billion.

b) Cost Recovery

If the $14 billion were to be recovered from the average annual energy output of 12,000 GW.h, that energy, fully costed at in-service, would be worth upwards of 9¢/kW.h. While levelized costs presumably would be lower, the impact on rates in 2024 could be substantial, unless the entire average plant output achieves 5x16 peak period export prices.

Unfortunately, such an outcome does not seem likely given the current market spread of 3¢/kW.h between on-peak and off-peak prices.

In the absence of very substantial carbon (CO2) price impacts in the MISO market, it is likely that off-peak energy prices will not move markedly above 5¢/kW.h (which is roughly double current sale values), consequently 5x16 on-peak prices would have to move to about 11 or 12¢/kW.h. to allow for MH's financial projections to be realized.

As illustrated in Figure 3.3 (from the 2008 GRA), MH continued to forecast export prices that would reflect a significant GHG premium beginning in 2015/16 and, if projected to 2024, would indicate an average export revenue rate of about 12¢/kW.h.

Such forecasts imply a substantial GHG premium of at least 3¢/kW.h being applied to existing MISO coal generated electricity. Longer term, coal generation prices might have to be more than double current values in the MISO area.

To ensure an appropriate economic return on new investments, MH will look to achieve average export prices of about 12¢/kW.h. This would suggest that the EIIR could increase by a factor of 2.5 over the next ten years. However, assuming an average 2.9% annual rate increase, the heritage rate might only go up by about 50% during that same period, from 2.42¢/kW.h to 3.6¢/kW.h. A large spread of about 8¢/kW.h between the first and second tier rates could be problematic, and the implications of such a development has yet to be fully researched and tested.

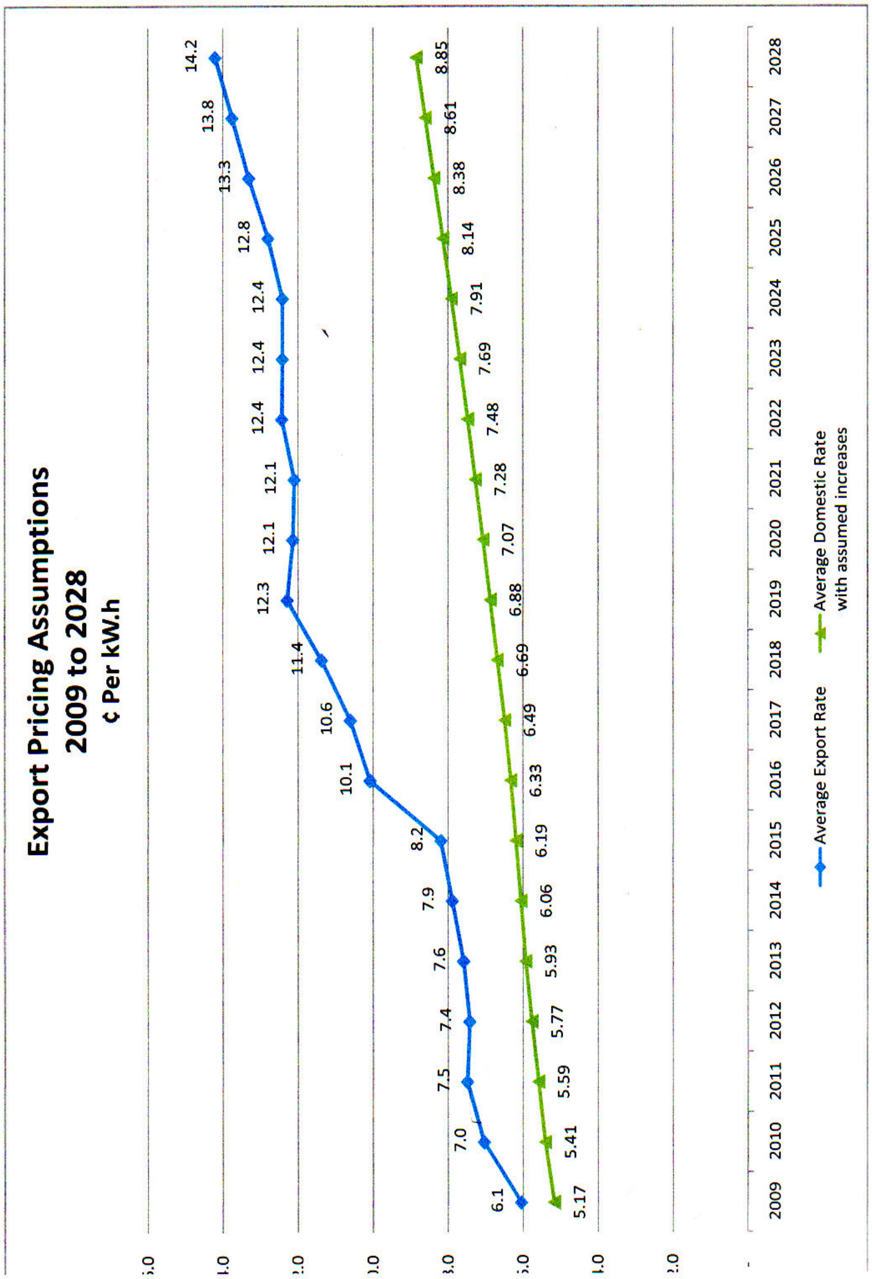


FIGURE 3.3

c) Comparison of Export Loads to EIIR Loads

From the Power Resource Plan, it is reasonable to infer that currently:

- 3,600 GW.h of firm contract exports employ about 700 MW of generation capacity.

- In contrast, 6,600 GW.h of GSL >30 base load requires 1,000 MW of generation capacity.

- 3,300 GW.h of consumption of four targeted customers requires 360 MW of generating capacity.

- The NSP/Xcel contract extension at 375 MW will involve 1,560 GW.h of 5x16 energy.

A doubling of the load for the four targeted customers would require a similar amount of energy as the fully-committed portion of contract load, yet would only require 50% of the additional generating capacity.

While capacity is not the only driving force for new generation, it can be concluded that 5x16 export sales potentially have a greater MC (based on deferrals) than comparable levels of energy going to EIIR customers.

5.0 EIIR Revenue Outlook

5.1 Revenue Impacts

5.1.1 MH's Position

MH's 2008 EIIR proposal would, over the next 10-15 years, derive additional second-tier rate revenue from four or five GSL >30 customers, which would annually pay the 2nd tier rate (approximately 4.8¢/kW.h) on up to 1,000 GW.h of load growth. After March 31, 2008, this translates into average annual revenues of $25 million, if the EIIR remains at currently proposed levels and no DSM credits are allowed.

If past DSM was fully credited (as proposed by MH), it can be speculated that the additional EIIR revenue would have been lower, say about $17-19 million/year for 700-800 GW.h.

In comparison, the previously proposed EIIR (at the 2008 GRA) would be expected to produce annual revenues of $40-60 million/year from a somewhat larger number of customers (at least five and no more than 14), which would be paying a 2nd tier rate (approximately 5.6¢/kW.h) on 1,300 to 1,900 GW.h of load growth.

Because of considerable structural differences (and in the absence of detailed customer data), it has not been possible to entirely reconcile the EIIR revenue impacts of IFF 08-1 and IFF 07-1.

In defining the lost export revenues, MH takes the position in this EIIR Application that all reductions in industrial energy consumption can be sold at firm peak prices (which averaged 5.53¢/kW.h in 2006/07 and 2007/08). On this basis, MH has estimated that the exports would produce about $10 million/year more revenue than industrial load growth under the EIIR.

In Exhibit #MH-18, MH has demonstrated that an equal combination of peak and off-peak pricing of energy would only produce about half as much revenue (e.g., $12-15 million/year) as the EIIR proposed. MH does not agree with this pricing premise.

Fiscal Year Ending ($000's)	Original EIIR Proposal IFF 07-1 ($)	Current EIIR Proposal IFF 08-1 ($)	Scenario 1 ($)	Scenario 2 ($)	Scenario 3 ($)	Scenario 4 ($)
2009	15,065	--	--	--	--	--
2010	31,051	13,151	5,746	6,658	6,255	7,166
2011	39,302	20,075	8,789	10,183	9,564	10,958
2012	42,791	24,578	10,771	12,478	11,718	13,425
2013	46,279	27,327	11,988	13,887	13,039	14,938
2014	49,767	25,479	11,178	12,949	12,159	13,930
2015	53,256	23,881	10,479	12,139	11,398	13,059
2016	56,744	23,353	10,248	11,872	11,147	12,771
2017	60,233	23,359	10,252	11,876	11,125	12,774
2018	63,721	23,354	10,250	11,874	11,148	12,772

Notes:

1. *On-peak hours were defined as Monday to Friday inclusive for the hours of 6:00 a.m. to 10:00 p.m. All other hours were considered off-peak.*

2. *MH has assumed that future customer loads will be distributed in the same proportion (between on-peak and off-peak) as current loads. Each affected customer's actual 2007/08 data was used in determining the percentage of on-peak and off-peak kW.h. These percentages were then applied to the individual customers above baseline energy. To the extent that customers were able to shift load to the off-peak in response to the lower price, the incremental revenue from Scenario 1-4 will be further reduced.*

3. *The following rates were used in deriving the incremental energy associated with each scenario. Scenario 1 rates are based on dependable sales only for peak period, but are based on opportunity sales for off-peak period. Scenario 2 rates include both dependable and opportunity sales for the on-peak sales. Scenarios 3 and 4 have the same on-peak rates as Scenarios 1 and 2 respectively, but the off-peak rate is set equal to the below baseline rate. In all cases, an amount related to the demand charge has been backed out of the average export revenue amount. The energy equivalent of the demand charge was based on a GS large load factor of 83%.*

The following rates were utilized in the above scenarios:

	GSL >100 kV		**GSL 30-100 kV**	
	On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**
Below baseline	2.42¢	2.42¢	2.47¢	2.47¢
Previous EIIR above BL (2008) GRA	5.56¢	5.56¢		
Current EIIR above BL rates	4.79¢	4.79¢	4.88¢	4.88¢
Scenario 1	4.83¢	2.25¢	4.92¢	2.29¢
Scenario 2	5.18¢	2.25¢	5.28¢	2.29¢
Scenario 3	4.83¢	2.42¢	4.92¢	2.47¢
Scenario 4	5.18¢	2.42¢	5.28¢	2.47¢

[Source: Exhibit #MH-18]

The EIIR proposal presented at the 2008 GRA was based on the principle that the revenue from the new rates would equal the foregone revenues of the same energy as if it had been sold in the export market, achieving revenue neutrality for the Corporation, but not for either the Rate Class or an individual customer.

In Order 116/08, the Board recommended MH explore options including:

> *"Keeping the overall implications for revenue requirement neutral. The Board does not consider MH's proposal revenue-neutral as presented in MH's filed Proof of Revenue and IFF."*

As with the previous proposal, MH's current proposed EIIR is intended to limit the revenue losses from energy-intensive domestic load displacing exports. The now-proposed EIIR is not intended to be revenue neutral with respect to current rates for industrial customers.

5.1.2 Examination of Evidence

The basic premise that all reduced industrial energy consumption can be converted to peak (5x16) export sales appears inconsistent with MH's operational realities.

In scheduling exports, MH faces peak period constraints from hydraulic generation capacity in winter, transmission tie-line capacity in summer, market receptivity, (particularly in the spring or fall), and generation energy in below-average flow years. It is the combination of these limits, the amount of off-peak energy savings, and MH's ability to shape off-peak energy gains, that will determine peak energy sales.

MH in recent years has been faced with selling substantial amounts of surplus energy into the off-peak market, and at prices less than 50% of the proposed proxy price. If the ability to reshape off-peak were unlimited, MH would have looked to avoid these off-peak sales.

In Exhibit #MH-18, MH assumed an equal combination of peak and off-peak sales in Scenarios 1 and 2, with off-peak energy prices modeled at 2.25¢/kW.h. This presumes no ‘energy shaping’ (i.e. moving energy from off-peak to on-peak) and, as such, may under-value the energy. Because the off-peak energy for industry has assured availability, a case can be made for using the current heritage price of 2.42¢/kW.h for the off-peak price, as per Scenarios 3 and 4.

If there are no growth allowances or DSM credits applied to the CBEL definition, the revenue achieved from a peak/off-peak EIIR would likely be about 40% greater than Scenarios 3 and 4, or about $20 million/year.

5.1.3 Revenue Impact

It is the Board’s view that the EIIR proxy rate of 5.53¢/kW.h should only be applied to peak industrial growth. Off-peak growth should attract a lower rate equal to the existing (heritage) rate for GSL >30 customers.

The Board intends that the EIIR will no more than offset revenue that might be achievable on the export market for the industrial growth energy. Domestic rates should not subsidize export sales.

5.2 Periodic EIIR Adjustment

5.2.1 MH’s Position

MH’s proposed second tier rate increase is expected to achieve the same amount of revenue as would be derived from the sale of 1,000 GW.h/year on the export market. All energy is assumed to achieve peak period prices.

MH has suggested that the EIIR would be subject to periodic proxy price revisions to reflect export market price increases. However, the EIIR would not be subject to general rate increases.

5.2.2 Examination of Evidence

Assuming a three-year periodic revision relative to MH's most recent export price forecast (derived from 20-year IFF 08-1), the proxy price might progressively increase to 7¢/kW.h in 2011 (from 5.5¢/kW.h as initially proposed) to 8¢/kW.h in 2014 to 10-11¢/kW.h in 2017, and 12¢/kW.h in 2020.

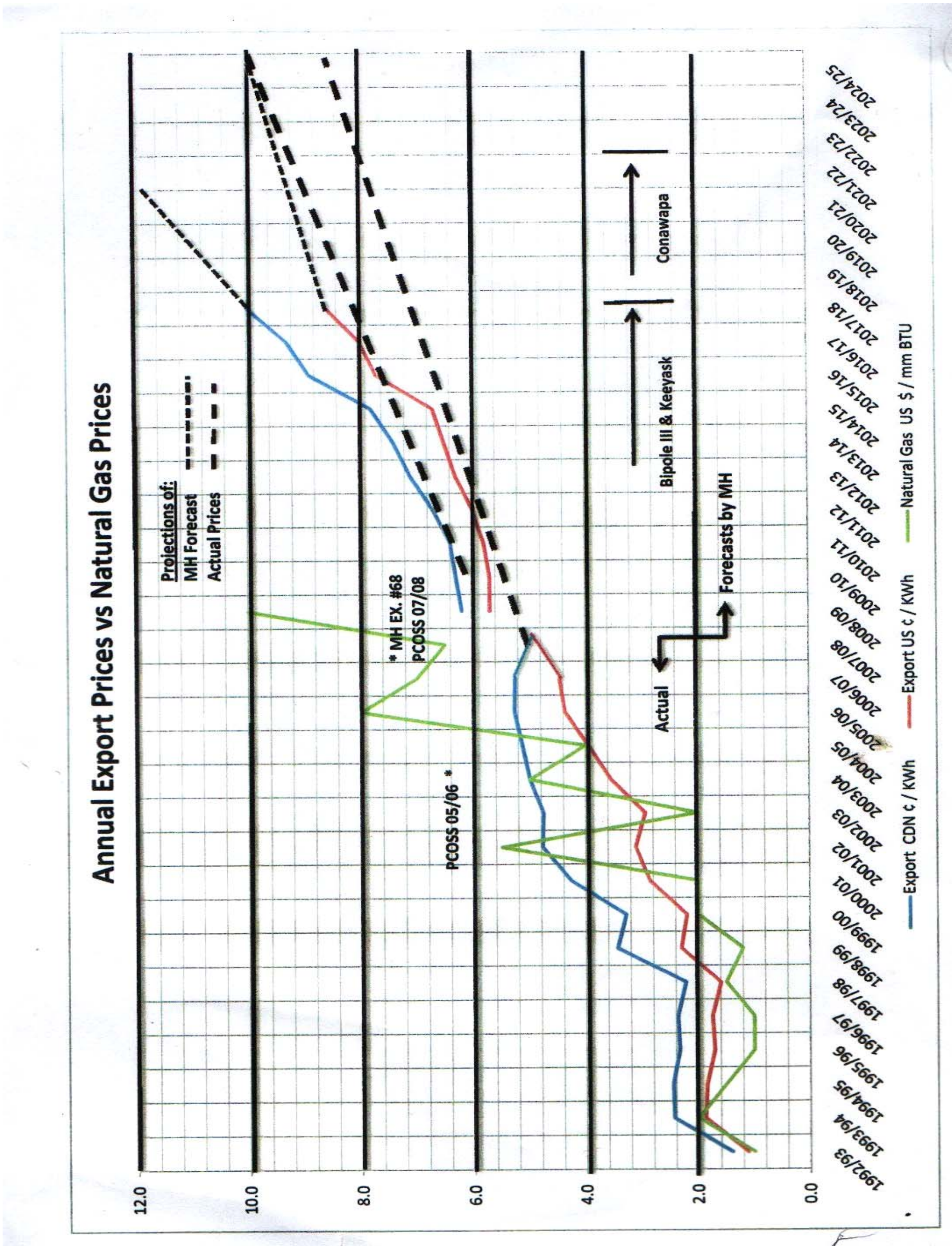
MH's EIIR revenue forecasts assumed that the proxy price remained constant at 5.53¢/kW.h, and MH's additional revenues would be in the $25 million range. Proxy price escalation could have "order of magnitude" type consequences. If the EIIR were applied to peak load growth only, the annual revenue would be in the $10-12 million range, with growth and DSM allowances, or about $20 million/year with no allowances.

The argument for using future forecast export prices instead of historical prices is flawed. MH has, in the last few years, been forecasting average market prices upward of 6-7¢/kW.h while the actual average price has been in the 5.0-5.5¢/kW.h range.

At the 2008/09 GRA, MH indicated that the seemingly high export price forecasts were not solely contingent on a substantial GHG premium, but would also (in part) reflect the strong upward trend in natural gas prices. There is reason to believe, as shown in Figure 3.4, that the upward trend is not being sustained and furthermore, that electricity prices in the MISO market cannot be reliability linked to natural gas prices.

A historical proxy price, in lieu of a future export market price forecast, is currently more transparent and likely to provide greater EIIR stability.

The RCM/TREE suggestion that Wuskwatim prices should be substituted for the EIIR when export prices do not achieve forecast levels has limited, if any, merit. It goes contrary to the primary premise that the EIIR is justified because industrial rates generate less revenue than export prices.


Annual Export Prices vs Natural Gas Prices
Projections of:
MH Forecast
Actual Prices
* MH EX. #68
PCOSS 07/08
PCOSS 05/06 *
Bipole III & Keeyask
Conawapa
Actual
Forecasts by MH
12.0
10.0
8.0
6.0
4.0
2.0
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1992/93
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2022/23
2023/24
2024/25
Export CDN ¢ / KWh
Export US ¢ / KWh
Natural Gas US $ / mm BTU

FIGURE 3.4

6.0 Other Jurisdictions

6.1 Quebec

The approach taken by the Province of Quebec to address the issue of attraction of large industrial loads to its low rate regime jurisdiction is to relieve Hydro-Quebec of its obligation to serve loads greater than 50 MW.

For loads under 50 MW, Hydro Quebec is obligated to serve the incremental load at embedded costs. The Quebec Government has taken on the role of assessing which companies in excess of 50 MW bring sufficient benefits to be eligible for heritage electricity rates. Hydro-Quebec is not involved in the decision.

The price for power for loads larger than 50 MW is determined by the Government of Quebec, perhaps through negotiation, and Quebec Hydro is apparently to be reimbursed for revenue shortfalls.

6.2 British Columbia

Mr. Ostergaard, a former chair of the British Columbia Utilities Commission (BCUC), who appeared on behalf of MIPUG, provided perspectives of the industrial power rate regime in place in British Columbia.

Mr. Ostergaard stated the gap between embedded cost rates and marginal values related to bulk Power Supply, and the issue of fairness and financial impact on utilities, are not unique to Manitoba.

In BC the gap between embedded costs and marginal value of new supply has not been accepted as a rationale for imposing marginal cost-based rates specifically focused for new or expanded loads for any customer or customer class. Mr. Ostergaard stated it is recognized that all classes of customers in all loads contribute to load growth and thereby drive costs related to new supply.

The central focus is also not on any specific class. A broader approach has evolved to manage the issue with energy efficient rates being a fundamental underpinning to overall BC Energy Policy. Mr. Ostergaard stated that the evolution of efficiency focused rates has taken several years of concerted efforts by the BC Government, the BCUC, BC Hydro and stakeholders.

6.2.1 Transmission Service - Stepped Rate Proposal

Mr. Ostergaard stated that the rate was developed only after a process that included significant customer consultation. BC announced a Stepped Rate policy for industrial customers in a 2002 energy plan, which was approved by the BCUC in 2005 after a negotiated settlement process.

Under the *Stepped Rate Proposal,* all transmission level customers served at transmission voltages at greater than 60 kV are to have a Customer Base Load (CBL) of energy established (where 90 percent of the CBL will be served at embedded costs); the remaining 10 percent to be served at marginal cost. The embedded cost is set to be revenue-neutral (with respect to the total CBL), as the higher cost of the second block rate is offset by reductions to the price of the first block rate.

Customers’ CBL are based on customers’ historic annual energy consumption in kW.h, as approved by the BCUC. The BC Stepped Rate Proposal has no cap on each customer’s consumption growth, and the CBL is adjusted annually to reflect long-term changes affecting the customer's plant (plant expansions or contractions, or other changes such as labour disputes).

The CBL is adjusted in this manner in order to ensure that it continues as an appropriate baseline to encourage electricity conservation and efficiency of use, while not discouraging economic growth. All CBLs are subject to final approval by the BCUC. In the event of a disagreement between the customer and BC Hydro on the CBL, the customer can raise the disagreement with the BCUC.

The Stepped Rate Proposal is intended to be revenue-neutral with respect to the domestic class and was designed to promote energy efficiency. Mr. Ostergaard stated that the higher second block rate provided the consumer greater incentive to cut back on electricity use, or to invest in cost-effective energy efficiency or self-generation for that portion of the consumption exposed to the second block rate. The total cost to the consumer and the total revenue to the utility are unchanged.

The current Stepped Rate (effective May 30, 2008) includes a demand charge of $5.036 per kV.A (kilo-volt amperes) and an average energy rate recovered of 2.952¢ per kW.h where the first block rate is set at 2.462¢/kW.h (below embedded costs) and is applied to all kW.h up to and including 90% of the customers CBL, with 7.360¢/kW.h charged on all consumption above 90% of the CBL for the year. Based on the construct of the rate, 2.952¢/kW.h is collected on the CBL of the customer as follows:

	Proportion of CBL	Rate Applied (¢ per kW.h)	Blended Rate (¢ per kW.h)
First Block (Below Embedded Cost)	90%	2.462	2.216
Second Block (At Marginal Cost)	10%	7.360	0.736
Embedded Cost	**100%**		**2.952**

Any consumption above the CBL would attract rates at the second block marginal cost.

Mr. Ostergaard stated that the determination of a transparent and fair marginal cost rate was a key consideration for the BCUC in 2003 when it was reviewing a Stepped Rate proposal. Mr. Ostergaard stated that many options were presented to the BCUC, with the overriding principle being that the rate should be simple to understand, transparent, focused on the long-term, and capable of independent verification without any issues related to confidentiality.

The marginal cost rate ultimately set is to be based on BC Hydro's average long-term opportunity cost of new supply; specifically, the average price paid to new Independent Power Producers (IPP), pursuant to the most recent call for tenders. Mr. Ostergaard stated that British Columbia considered (but did not include) an export price in the determination of its marginal cost rate.

As an alternative to the Stepped Rate, customers could elect to enter into a Retail Access Program with an IPP, or opt for a Time of Use (TOU) Stepped Rate program. Under this latter program, a separate CBL is determined -- seasonally for the Spring (May and June) and the remaining period (March/April, and July to October). As well, two separate energy CBL's for the High and Low Load hours during the Winter Period (November to February) are established.

Mr. Ostergaard indicated that no customers have chosen this TOU alternative rate option, an occurrence that Mr. Ostergaard was unable to explain other than speculating that the rate is not as attractive as the Stepped Rate structure, in the sense that industrial customers have to trade off shifting their consumption requirements to take advantage of lower priced electricity at certain hours of the day.

Mr. Ostergaard stated the outcome of the establishment of Stepped Rates is that, in his view, industrial customers feel that the Stepped Rates are working; sending a proper price signal to industry that has resulted in significant DSM savings that would not otherwise have occurred. However, residential customers have expressed concerns that the consistent under-recovery within the Industrial customer class may lead to rate-shifting (depending on regulatory accounting treatment), if BC Hydro attempts to recover the under recovered amounts from other customer groups.

Mr. Ostergaard further confirmed that if an industrial customer's group consumption was disproportionately larger than fellow class members, and was more than the class average, the costs related to the growth in the higher consumption would be shared with all ratepayers.

Mr. Ostergaard recommended that for existing customers, some form of Stepped Rate system (to discourage consumption at the margin and to encourage efficiency investments, which works in British Columbia), may be appropriate for Manitoba.

6.2.2 Electric Tariff Supplement No.6 (TS6)

The BC policy relating to very large industrial loads is dealt with by Electric Tariff Supplement No.6 (TS6), which was approved by the BCUC in 1991. The tariff addresses the potential financial implications for BC Hydro and its domestic ratepayers arising from incremental generation and transmission costs due to new very large industrial loads. BC Hydro is obligated to serve new and large industrial loads that conform to the tariff at standard embedded cost based rates.

Through the tariff, one-time payments of capital contributions from industry are determined for transmission and generation cost implications for connecting industrial loads exceeding 150 MV.A (mega-volt amperes), or approximately 150 MW (maximum energy usage of about 1,100 GW.H/yr) for any single expansion.

TS6 sets out how the costs of connection for a new industrial customer is to be shared between the new customer and BC Hydro. BC Hydro may pay a portion of the cost of required reinforcements of the existing transmission system (based on a formula that calculates BC Hydro's contribution) based on a net revenue expected from the new load, and applies a rate of return to that revenue. The formula also deducts the depreciation of the transmission investment in addition to other possible benefits (such as savings associated with displacing diesel generation).

The formula used to determine the need for a contribution is net revenue increase times seven years, plus 50% of one year's depreciation, as well as other benefits, to be determined by BC Hydro.

A higher load means higher net revenues, hence a higher contribution from BC Hydro. However, if the newer incremental load exceeds 150 MV.A, the industrial customer is also required to pay the capital cost of generation needed to serve the new load. In addition all new customers are required to provide security through a letter of credit, in order to reduce the default and performance risk related to the new load, which is refundable over the years as the new customer takes the electricity as planned, for the purposes of calculating the formula.

Mr. Ostergaard indicated that TS6 customers tend not to pay any system reinforcement costs but do tend to pay the full cost of the transmission extension and connection to the system (based on that formula), because BC Hydro's revenues over the number of years usually fully offset the costs of transmission reinforcement under the formula.

Mr. Ostergaard provided examples of the application of TS6:

> *In 2002, a potential customer proposed an aluminum smelter on Vancouver Island that would need 650 MW of power. In applying TS6, BC Hydro determined that the customer would have to make a contribution that would be $1.27 billion, to provide both generation and transmission upgrades to serve the load. The smelter did not proceed.*
>
> *Another application of the tariff dealt with the expansion of an oil pipeline facility with an incremental load to BC Hydro of 62 MW. Under TS6, the customer was required to pay an estimated $3 million cost to interconnect to the transmission system. The expansion required an estimated $32 million cost to reinforce the transmission system to serve the incremental loads which was paid by BC Hydro and recovered in its transmission revenue requirement; the BC Hydro offset supported the full system reinforcement cost, and no customer contribution was required. The client provided a letter of credit and guarantee as security, to be drawn down by BC Hydro if incremental revenues did not materialize.*

Mr. Ostergaard stated that for new customers in Manitoba, there is a need (in a way similar to what was described in TS6) to have them pay a fair share of costs in their new jurisdiction; but at the same time, not being so onerous that it will discourage new industrial loads to locate in Manitoba.

Mr. Ostergaard further stated that what British Columbia has done with industrial loads is to try to send price signals at the margin for industry to become efficient, self-generate, find efficiencies through power smart programs on the margin, and to pay much of the freight; but not to the point where B.C. is saying ‘no’ to new industry based on electricity costs.

6.2.3 Discriminatory Rate

MH argued in its rebuttal evidence that the evidence of MIPUG witnesses Bowman and McLaren recognizes that some form of rate discrimination may be proper, this to provide protection for other ratepayers.

MH argued that, in principle, some forms of discrimination are entirely appropriate. And, while both British Columbia and Quebec regimes do not deal specifically with rates for units of service, they do seek, in principle, to impose higher costs on large loads that create a need for infrastructure costs beyond what would be recovered in rates set on the basis of embedded cost.

In MH’s view, the terms in place in B.C. and Quebec provide, in principle,
useful precedents with respect to the appropriateness of some level of discrimination, although, in practice, they may be considerably less effective in protecting other ratepayers than MH’s proposal.

Mr. Bowman contended that the cases in Quebec or British Columbia are not actually a form of rate discrimination, as the jurisdictions have dealt with the issue without having to put in place a discriminatory rate regime.

And, with respect to Quebec, he suggested that there is a maximum obligation to serve that comes out of policies made by the Government of Quebec, and that government policy is not germane to regulatory policy. Bowman claimed that discrimination and the question of undue discrimination is a regulatory concept that arises and is tested within the regulatory arena, and that regulatory arena is defined by the laws and policies of the jurisdiction.

Also for Quebec, Mr. Bowman advised that the regulatory arena is defined to not include those customers, and that they are outside the regulatory framework. It is the law, and doesn't lend itself to a regulatory test in regard to whether the practice is discriminatory, according to Mr. Bowman.

With respect to the system in place in British Columbia, he stated that the regime in place includes a system extension approach, which is approved by the BCUC. For Mr. Bowman, the BCUC approach falls within the regulatory arena and is set up so that all customers pay contributions when they connect (as needed), under the same set of principles.

Mr. Bowman stated that the principle at 'play' is that, if a customer is connecting to the utility system, and as a result of connecting, new assets are required to be put in place to be able to supply that level of capacity, then that customer pays the increment for those assets, except where there is an offset by the revenues of the customer in the future.

6.2.4 Issues

While the Quebec process seems simple (in that the decision on major industrial expansion is left to government), it still remains necessary to logically define the service threshold limit and the components of cost that would flow to government.

For the Board to recommend a similar approach in Manitoba, it would require a new service extension policy with transparent applicability rules.

To implement the British Columbia approach, extensive consultation with industry (and involving government, the Utility, and other stakeholders) would be required. Such an approach in Manitoba would take time, and would delay putting into place the forms of protection sought by MH to protect today's ratepayers.

It would be necessary to determine the scope of capital contributions to G&T upgrades, the capacity threshold beyond which G&T contributions would be required, and whether the overall rate approach is to be revenue-neutral to the individual firm, industry class, or to the Utility, on both a short-term and long-term basis. This process would have to be integrated within a new Service Extension Policy.

7.0 Intervener Positions

7.1 The Coalition

7.1.2 The Problem

The Coalition stated that when the issue first emerged, the problem may have appeared to apply mainly to new, energy-intensive users (such as an aluminium smelter), and the implications of that new, energy-intensive user might strain the energy marketplace at a time when embedded costs for industrial customers were significantly below the price in the export market.

The Coalition further stated that the issue has now been more broadly defined to include disproportionate rapid growth of certain large existing energy-intensive customers over the short term, which brings into question issues of how to treat existing customers vs. new customers.

The Coalition agreed with MH that there's a fundamental issue of fairness and that an argument can be made that the rapid and unconstrained growth of large industrial users (whether from new or existing customers) may be imposing unfair rate pressures on other groups of customers. A large increase in large industrial usage will result in a significant opportunity cost, due to foregone export revenues. The Coalition cited MH's evidence, which included;

> *"…the sale of energy to large industrial customers typically earn the Corporation about 3.3¢ per kilowatt hour, compared to 5.5¢ on the export market. This rate differential (of about 2.2¢ per kW.h) must ultimately be recovered from other customers, unless steps are taken to address this revenue erosion."*

The Coalition further stated that large industrial customers are the most price responsive, noting that MH had stated that energy use is relatively inelastic for all customer classes, but large industrial customers are the most price elastic in the short-term and long-term. Large industrial customers have the greatest disparity between marginal cost and rates, and are experiencing the highest growth, both historically (when weather normalization is taken into account) and in the short-term forecasts.

The Coalition noted that, allowing for weather normalization from 1998/99 through 2007/08, the Residential class was growing at an annual rate of approximately 2%, while the GSL class (greater than 30 kV, energy-intensive only) had grown five times as fast on a percentage basis, doubling its consumption over the past 10 years.

Based on projections put forward by MH, the Coalition expected disproportionately rapid growth to continue over the next five years, with top industrial customers expected to account for about 68 percent of total system load growth within that period.

The Coalition stated that the revenue to be raised by MH's proposed EIIR ($10.5 million in 2009/10 and $18 million in 2010/11) represents 'revenue protection'. While it could be argued to be relatively small, a 1% or 2% rate impact is significant in the context of low-income consumers and those on fixed incomes.
On the other hand, the Coalition indicated a concern about the possible "chilling effect" the EIIR may have on certain types of industrial growth. The Coalition recommended that the Board preserve December 31, 2007 as the baseline date, until all issues related to the application have been resolved.

The Coalition also noted that, given the recent economic events and the slowing of the economy, the urgency in dealing with this issue may be reduced.

7.1.3 Manitoba Advantage

The Coalition stated that the fundamental premise under which MH has operated for many years, that of low embedded cost rates, is challenged with the EIIR Application, which represents a move to assigning market-based rates to a specific class of customers.

The Coalition noted that MH, working with the Province, had made tremendous achievements in bringing low-cost power to almost all Manitobans, with the exception of a few diesel communities; along with accomplishments such as rural electrification, the North Central Power Grid, Uniform Rates and a policy to provide the lowest rates in North America.

The Coalition further noted that MH has had an important role in stimulating the economy through Utility investments and low rates, which have helped with economic development and have minimized the impact of utility cost increases on low-income households.

The Coalition also noted that MH brings significant annual benefits to the Province, with water rental fees, debt guarantee fees, and a large corporation capital tax. The Coalition stated that the package of benefits associated with MH constituted the “Manitoba Advantage”, flowing from bountiful hydroelectric resources, access to export markets and creative policy choices.

The Coalition stated that policymakers made a conscious choice to price electricity for domestic consumers at average embedded cost rates, and not what the market would bear. This domestic priority was easy to maintain in the past when average embedded cost rates were generally higher than average export rates.

The Coalition questioned the move (with EIIR) to market-based rates on a non revenue-neutral basis, claiming that this could, directionally, lead to rejecting the Manitoba Advantage, rather than preserving what it considered a long-held social consensus.

7.1.4 Options

The Coalition further stated that MH's EIIR proposal presents only one solution, and a different process (such as an Alternatives Analysis) should have been undertaken, whereby the problem would be identified, key objectives and goals set, and options defined and tested. The Coalition indicated that the absence of such an analysis does not allow a satisfactory and thorough discussion and evaluation of all potential options.

In its final argument, the Coalition provided a limited Alternatives Analysis of options including MH's proposal, based on seven criteria. The four options evaluated included: MH'S proposal; RCM/TREE/Chernick proposal; BC Hydro Stepped Rates; and BC Hydro System Expansion constraints.

The Coalition reviewed the options to consider how each dealt with revenue protection; cost protection; economic development; efficiency price signals; fairness to customers; implementation difficulties; and rate stability and transparency.

While the Coalition concurred with efforts to protect revenue that it recognized in MH's proposal and RCM/TREE's approach, the Coalition advised that it had difficulty understanding what concept of revenue neutrality has been employed. Furthermore, the Coalition stated that if the Board considered energy efficiency as the number one priority, the EIIR proposal is not appropriate.

With respect to the BC Hydro approach, the Coalition reported that it saw value in some of the details, but not in the overall concept.

7.1.5 Growth Allowance

The Coalition expressed concern that the operation of the growth allowance may lead to the appearance that only certain types of firms are being targeted, and that there is a strong possibility that only the growth of chemical and petroleum firms would be affected by the EIIR.

7.1.6 Unduly Discriminatory

In terms of fairness, the Coalition expressed concern that the specific terms of the proposed growth allowances could result in only chemical and petroleum firms being affected by the EIIR. The Coalition also expressed concerns with the operation of the "hard cap" from a fairness point of view, as some may conclude that MH was targeting only one specific firm.

In addition, the unavoidable consequence of "drawing lines", whether it be the 100 GW.h trigger, the growth allowance or the 1500 GW hard cap, was that each measure would appear to disadvantage certain customers as compared to others.

Overall, the Coalition's main concern was the fairness of the approach, and it held significant concerns about the EIIR, both in terms of perception and whether or not it's unduly discriminatory. The Coalition further stated its belief that a reasonable argument could be made that the EIIR is not unduly discriminatory, but expressed the reservation that the "hard cap" may be vulnerable in that respect.

The Coalition provided its preliminary legal opinion, which raised questions as to the propriety of the Terms and Conditions of MH's proposed EIIR as they apply to MH's largest customer. Concern was raised as to the fairness of the treatment of that customer, and whether the EIIR was therefore 'unduly discriminatory'.

The Coalition recommended the Board reject the EIIR proposal and direct MH to provide a more thorough Alternative Analysis, one that would examine a variety of approaches and extension policies, whether it be BC's TS6, Centra's feasibility study approach, or another alternative. The Coalition further recommended that if the Board does adopt the EIIR approach, it should be gradually introduced.

7.1.7 Service Extension Policy

With respect to a Service Extension Policy, the Coalition suggested that it could prove to be an important tool in dealing with large industrial customers. However, for the Coalition, it is conceptually unclear how such a program would be utilized.

Given a lack of specific information and discussion in this hearing on MH's Service Extension Policy, the Coalition was not satisfied that the BC Hydro TS6, or the Centra Gas Feasibility Test, would be a better tool than the Energy Intensive Industry Rate.

7.2 MIPUG

MIPUG is an association of major industrial companies operating in Manitoba. MIPUG companies are significant contributors to Manitoba's economy, including in particular the communities in which they operate.

MIPUG reported that its members purchase nearly 5,200 GW.h hours of electricity at a cost of over $100 million annually, representing approximately 25% of MH's domestic sales. MIPUG also asserted that approximately 90% of MIPUG members' products are exported, and that MIPUG member companies employ over 4,500 Manitobans with an associated payroll and benefits of approximately $397 million. MIPUG members' facilities are predominantly located in rural and Northern Communities outside the City of Winnipeg, and their plant, property and equipment have a replacement value of over $2 billion.

MIPUG advised that, in 2006, its members paid taxes and fees to governments of over $95 million, in addition to over $69 million in employee remittances made to the Federal and Provincial governments.

MIPUG quoted Mr. Turner, President of MIPUG, as having said:

> *"the future growth of large industry in Manitoba depends on reliable firm power at fair and reasonable rates, rates that reflect cost of service principles and demonstrate commitment to innovative rate options that benefit industry, Manitoba Hydro, and the Province of Manitoba"*

Mr. Bowman and McLaren stated that MIPUG members, as major power users, have consistently expressed concern about the long-term interest of domestic customers. Their concerns include:

- The need for stability and predictability of domestic rates over the long as well as short-term;

- The need for strong regulatory oversight and approval of all rates charged by MH; and

- Assurances that rates to each customer class continue to reflect Cost of Service and are consistent with principles appropriate to Canadian regulatory practice for Crown electric utilities.

7.2.1 Standard of Review

In MIPUG's view, MH's EIIR proposal should be subjected to an onerous standard of review. From MIPUG's perspective, the Board is being asked to approve a proposal that:

- Deviates significantly from regulatory practice in this jurisdiction;

- Compromises fundamental principles and protection currently in place to protect ratepayers; and

- Implements either discriminatory or unduly discriminatory rates.

For MIPUG, such a proposal should only be permitted under very limited circumstances, where:

- A clear and well-supported need has been established;

- All information required to understand, test and determine the issue is on the record, and a complete analysis of the information has been performed;

- There is a comprehensive understanding and assessment of all options available that could reasonably address the utility's concern; and

- There is no reasonable alternative available to address the issue that would not require deviation from fundamental regulatory principles.

MIPUG stated that Order 116/08 required a high standard of review related to the EIIR proposal, noting specific concerns and providing suggestions and explicit directions regarding the information that the Board would require in order to review and approve a proposed rate of this type. MIPUG held that the Board had clearly indicated that it expected MH's application to identify and discuss options, taking into account specific concerns, including indicating how other jurisdictions have addressed the gap between embedded cost rates and marginal costs.

MIPUG noted that, concurrent with calling for a new rate application, the Board also directed, amongst other things, that MH file specific information on its Service Extension Policy, which was unilaterally suspended in 2005, in part due to MH's concern about new and expanding industrial loads in Manitoba.

Messrs. Bowman and McLaren opined that MH’s application neither addresses the Board’s concerns nor responds to directives arising out of order 116/08, and that the deficiencies were only partially addressed in responses in the interrogatory phase of the proceeding.

Bowman and McLaren further noted that the Board had indicated MH would be expected to provide:

- Conceptual options, including the preferred option;

- Options with respect to baseline and growth allowances;

- A view as to whether new industry should get any growth allowance at heritage rates;

- Options for setting marginal cost rates, including options that address transparency concerns related to the use of forecast export prices;

- Options that include time of use alternatives and variations to reflect the differing values of energy at different times;

- Options that provide for revenue neutrality; and

- Options to consider a marginal cost component for only a few customers, a single class or all classes served by Hydro.

Specifically, MIPUG cited the following Board positions:

1. With respect to the fairness principle, Bowman and McLaren noted Order 116/08:

   > *"the issue of the fairness of embedded cost rates, being considerably lower than marginal values of energy, and the potential financial impact on the utility, is not unique to Manitoba. The Board understands that other jurisdictions have, and continue, to face this issue"*

2. Export contracts:

   > *"MH should be required to reconcile its proposed treatment of energy – intensive industries with existing and proposed export contracts"*

3. Time of use rates:

Directive 22(a) required MH to provide this by September 30, 2008:

> *"A planned implementation strategy for time of use rates as appropriate to the classes with required metering technology already in place. Alternative rate strategies should be included for consideration at the upcoming energy intensive industry rate hearing"*

A key concern for MIPUG throughout the review of the EIIR application was its view that there were material deficiencies in MH's responses to Board directions regarding a wide array of matters (identifying and assessing different rate options, time of use rates, in-depth analysis of export market values, deferred generation and transmission values, as well as the background information on its suspended Service Extension Policy).

MIPUG held that little (if any) attention had been paid by MH to the Board's desire to have before it all relevant information on the above issues, and that much of the analysis relevant to the Board has not been filed. MIPUG submitted that on this basis alone, and given the discriminatory approach taken, the EIIR application should be rejected.

7.2.2 Discriminatory Rate

MIPUG stated that the EIIR is flawed, due to its unique and unprecedented departure from the Manitoba regulatory construct. For MIPUG, MH (as the monopoly supplier) has an overriding obligation to serve all customers in Manitoba.

MIPUG submitted that there are fundamental core principles or protections within the regulatory construct that require the Board to ensure that all customers are treated fairly and that just and reasonable rates are approved.

MIPUG stated that the EIIR application raises key issues of principle related to the seeking of fundamental changes to how rates are regulated for certain classes of customers as a whole, and for certain customers individually.

MIPUG cited the following distinct types of rate discrimination that would flow from the implementation of the EIIR rate proposal:

- Discriminatory relationships between rates for different classes and quantities of service. This form of discrimination between Customer Classes would focus primarily on the principles applied to different customer classes. In these circumstances, the Board must make a determination of whether the proposal is duly or unduly discriminatory, using the usual legal tests for discrimination.

- Discrimination between treatment afforded to specific customers within a class who were charged different rates for substantially the same product, rendered under similar conditions; this is referred to in Bonbright as "personal discrimination", and is described as anathema to rate regulation, i.e., "There's no test of due or undue discrimination in the circumstances and where these facts exist there can be no justification for the rate."[1]

[1] *James Bonbright, Principals of Public Utility Rates on, page 370-71 notes as "unjust" and without qualification "a certain over type of discrimination… namely, so-called "personal discrimination", whereby different customers are charged different rates for substantially the same product, rendered under similar conditions." Bonbright goes on to note that even where rules against unjust discrimination have been relaxed –*

> *person discrimination is still not acceptable. Later on page 374 this is described as "the type of practice forbidden without qualification" [i.e., "the practice of charging different rates to different customers for substantially the same product".*

MIPUG stated that MH's rate proposal reflects personal discrimination as it is targeted at a few loads (firms) that have nothing notable in common as a "Class" except for plans to grow, or commitments to expansion.

Mr. Bowman stated that an EIIR rate would be unduly discriminatory because it targets no more than a few loads; loads that have the same characteristics will pay different rates at different times under the proposal. The EIIR represents the different treatment of similar customers, and if the new rate was implemented, it would unjustly discriminate against a few targeted domestic customers, by severing overall charges to them from heritage embedded cost rates applicable to all other customers within the > 30 KV GSL Classes.

MIPUG claimed that only 3 to 5 customers within the group of 10 or 11 eligible customers using 100 GW hours per year would be subject to the second tier rate of the EIIR.

MIPUG pointed out the case of MH's largest customer, and the 1,500 GW.h cap designed to constrain continued growth by that firm. For MIPUG, the cap singled out this customer and ensured that that it would be precluded from expanding at embedded cost rates.

MIPUG further noted that MH's rationale for the 1,500 GW.h cap was to level the competitive playing field between a large producer and another (smaller) chemical producer in the province. For MIPUG, based on the premise it was levelling the competitive playing field, MH had determined to discriminate against one customer by preventing any further incremental growth by that customer at embedded cost rates, eliminating the full advantage of available Power Smart credits for that customer, while at the same time, providing for its competitor to continue to grow with a CBEL determined based on the available Power Smart credits and growth allowances.

MIPUG stated MH's 1,500 GW.h cap proposal does not "level the competitive playing field", but merely shifts the advantage elsewhere and raises a fundamental concern. MIPUG asked "where in MH's mandate is it suggested that its role includes interfering in or balancing competitive concerns between its customers?" MIPUG asserted that MH's EIIR proposal will interfere with competitive concerns between two customers in the same rate Class.

MIPUG took the view that the elimination of the 1,500 GW cap from the EIIR proposal would not correct the discrimination inherent in the EIIR proposal, with specific individual customers within the GSL >30 classes to be treated differently than other customers in the class.

With respect to the growth allowance, MIPUG indicated that the EIIR was discriminatory, citing MH's indication (under cross examination) that the growth allowance within the EIIR was designed so that most GSL >30 customers potentially affected by the rate would be able to grow without paying the Tier 2 rate.

MIPUG noted that MH had also acknowledged that the growth allowance was essentially a negotiated amount between MH and some of its largest customers, and that the growth allowances were designed to allow certain existing companies to grow at Tier 1 rates. Specifically, MIPUG suggested that MH had acted to ensure that primary metal customers were not affected by the EIIR proposal.

MIPUG held that the proposal creates competitive issues between new and existing companies. MIPUG noted that the 100 GW.h baseline for new customers would provide a competitive disadvantage to a new customer in competition with an existing customer. Based on the scenario that the new customer and existing customer required 200 GW.h in energy, MH had indicated that the new customer would be at a competitive disadvantage if electricity prices represented a sizable portion of their operating costs.

MIPUG submitted that MH's EIIR proposal had been transformed into a patently "personal discrimination" rate scheme, and that, on that basis alone, the proposal must be rejected by the Board.

7.2.3 The Problem

MIPUG questioned the validity of MH's basic assertion that the need for the EIIR relates to the risk that "large energy intensive industry is being attracted to Manitoba on a scale large enough to threaten the corporation's revenue position".

MIPUG noted that the corporation's witnesses portray MH as experiencing "significant revenue loss" through expansion of the energy-intensive industry in Manitoba, and in particular experiencing revenue loss as a result of the rate of growth of the targeted customers.

MIPUG noted that, contrary to the Board's direction in Order 117/06, the new EIIR does not create a rate class for new energy-intensive industry, but rather is focused primarily on well-established existing customers. MIPUG further noted that the new rate will adversely affect well-established existing pipeline and chemical company customers, which will be assessed two-thirds of the revenue expected to be generated by the plan. MIPUG further asserted that two-thirds of the revenue to be generated from the EIIR would be from pipeline expansions within Manitoba, which do not use electricity as a manufacturing input.

MIPUG stated that the evidence does not demonstrate a need for the EIIR proposal. For MIPUG, in order to support a proposal that breaks with all regulatory principle and precedent by actively discriminating against certain groups of customers (and certain specific customers), MH must clearly demonstrate four basic propositions:

1. MH will experience significant future revenue loss due to the future expansion of the energy intensive industry in the province;

2. Manitoba, in the future, will experience a period of unusually rapid growth in the energy-intensive industry;

3. The future influx of energy-intensive industry load will be due to the low rates available in Manitoba; and

4. When energy-intensive industry grows, other ratepayers and the overall public interest are adversely affected.

MIPUG submitted that MH needs to first demonstrate a critical policy objective, and then demonstrate that the EIIR, as it proposes, is the best available option to address that objective.

MIPUG suggested that the current gap between embedded costs and marginal costs is not unique to Manitoba, and that the gap is less material in Manitoba than in most other Canadian jurisdictions.

MIPUG suggested the gap was more pronounced in other jurisdictions (e.g. 4¢ in British Columbia vs. 2¢ in Manitoba), yet the regulators in BC have not deemed it appropriate to discriminate against large industrial customers to address this concern.

Mr. Ostergaard noted that

> *"In BC the gap between embedded cost and marginal cost has not been accepted as a rationale for imposing marginal cost based rates specifically focused for new or expanded loads for any customer or customer class. A broader approach is to manage this issue with energy- efficient rates as a fundamental underpinning of overall BC energy policy".*

With respect to MH's claim of an accelerated pace of industrial load growth**,** MIPUG contended that actual industrial load growth over the last nine years has not been materially different than that forecast by MH in 1998, and that the forecast of industrial load growth over the next nine years indicates no dramatic increases are expected, compared to actual load growth over the last nine years.

As to MH's concerns about the risk of a future influx of new industrial load as a result of Manitoba's low rates, MIPUG further asserted that there was no evidence that new energy intensive load is imminent. MIPUG noted that MH has confirmed that only one new industrial firm had located in Manitoba during the last 10 years (with usage exceeding 100 GW.h or more during the first year of operation).

MIPUG asserted that evidence presented at the 2008 GRA, and at this proceeding, indicate that energy-intensive loads (such as server farms and smelters) have tended to locate elsewhere.

With respect to MH's claim that industrial growth in Manitoba adversely affects other customers, MIPUG noted that, in a regulated system, with rates reflecting embedded costs and applied to all classes, load growth by any customer class increases the average bulk power costs to the system.

MIPUG concluded that none of MH's assertions, when subjected to scrutiny, support the need for the EIIR. On the contrary, for MIPUG the EIIR proposal represents risk to the Manitoba economy, in that such discriminatory rate proposals will discourage highly desirable economic growth in Manitoba.

MH has indicated that "in light of the current economic turmoil" facing Manitoba and the rest of the world, some customer expansions have been deferred, and many of MH's top ten customers are experiencing slowdowns. With respect to the targeted load growth of 700 GW.h in the application, MH has indicated about 25% to 50% of that growth may be deferred to some point in the future, as a result of the current economic slowdown.

7.2.3 Targeted Industrial Growth Issues

Efficiency and price signal Issues

MIPUG asserts that the EIIR proposal provides no meaningful contribution or relationship to addressing efficiency and price signal issues. And, as the current proposal is expected to affect only 3 to 5 customers, this is far too few customers to achieve any significant efficiency related objectives.

MIPUG noted that MH acknowledged that no price signal is provided to most large industrial customers; 252 customers in the GSL < 30 kV and about 24 customers in the GSL> 30kV are unaffected by the EIIR.

MIPUG noted that some customers, notably the pipelines, cannot effectively avoid the rate as the pipeline expansions have been committed. MIPUG quoted Mr. Svidal of Enbridge, who noted that pipeline firms look to economies of scale, which means that "the most efficient pipeline expansion is at existing pumping stations and along existing right of ways".

MIPUG further indicated that MH failed to give adequate consideration to efficiency programs, or measures that could benefit both MH and customers affected by the rate. MIPUG noted that the presentations by Mr. Turner and Mr. Svidal indicated a willingness to explore time of use rates or other load shifting measures. Mr. Bowman stated:

> *"rather than the focus that's been there to-date on how to target three (3) customers, spend the time figuring out how to get efficient price signals… in as many situations is possible to all of the different customers"*

Mr. Bowman stated that MH's current proposal is oriented toward a different set of objectives, being MH's revenue protection and system planning, which are fundamentally different to the objective of establishing a rate that encourages efficiency. Due to these conflicting objectives, MIPUG recommended that the current rate proposal should not form the basis of the development of a rate that promotes efficiency.

MIPUG submitted that the implementation of meaningful efficiency and price signal rates that treat all customers fairly, requires extensive consultation and analysis which has not yet occurred. Mr. Bowman indicated much work would need to be done to set out objectives that meet the needs of customers, including an educational process, building buy-in and letting customers consider how they would respond to a rate proposal that could work for Manitoba.

Bulk Power System Planning Issues

MIPUG noted concerns were raised by the Board in Orders 90/08 and 116/08 regarding MH's business model, the pursuit of exports and related plant advancement, and whether industrial sales growth does in fact displace current export revenues to the extent suggested by MH.

MIPUG noted that in Order 90/08 the Board stated:

> *"With respect to MH's capital expenditures which may exceed $18 billion over the next 15 years, with MH likely committed through its export arrangements to develop Keeyask G.S. and Conawapa G.S., MH's debt may grow to over $20 billion. The Board is concerned that the magnitude of MH's capital program could significantly increase from projected levels if the recently experienced construction cost escalation is sustained. The financial consequences of such an increase would be exacerbated if interest rates, currently at historical lows, move up.*
>
> *Despite the Board's limited mandate with respect to capital costs, the Board expresses concern, not to be confused with opposition, with the unprecedented capital expenditure levels, and questions whether the export revenue stream from new generation and transmission projects will be sufficient to cover the financial obligations related to these works, given the inherent risks that are present and lie ahead."*

MIPUG also cited Order 116/08 in which the Board stated:

> *"And, given the emphasis placed on exports (the source of rate subsidies for domestic customers and capital for early construction), and the risks for domestic customers if export commitments and water conditions collide, it could lead to significant financial losses.*
>
> *The Board agrees with Interveners that regulatory review of the impact on consumer rates that MH's planned capital*

> *program may have is warranted, and that such a review should consider the risks faced by the Corporation and its ratepayers.*
>
> *In light of the unprecedented capital expansion now under consideration, the Board will direct MH to propose to the Board on or before January 15, 2009 the terms of reference for a regulatory review of MH's planned Capital Program and its possible implications for consumer rates. The Board will also direct MH to prepare a study, for filing with the Board by January 15, 2009, a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending, taking into account revenue growth, variable interest rates, inflation experience and risk, and potential further currency fluctuation."*

Mr. Bowman and Mr. McLaren submitted that no evidence has been provided by MH that would be sufficient to assist the Board in addressing concerns and/or uncertainties related to MH's current business model; nor have any assurances been provided to the Board that exports will yield equal or superior economic benefits to Manitoba than the loads being targeted by the EIIR.

MIPUG indicated that it has been supportive in the past of MH's pursuit of serving exports by advancing generation development [as a second priority to domestic service]. MIPUG submitted that the current proposal alters MH's obligation to serve by actively discouraging certain domestic industrial load growth based on a presumed priority for exports. Given this approach and its impact on domestic load related issues, MIPUG indicated that it is timely for the Board to review and test MH's long-term business plan.

7.2.4 Service Extension Policy

MIPUG stated that the treatment of MH's Service Extension Policy raises issues of fairness and transparency for affected customers that require resolution. MIPUG further noted that MH failed to respond to the Board's directive:

> *"MH to provide further and complete explanation as to the use and suspension of its Service Extension Policy, as herein requested, by December 1, 2008 for discussion at the upcoming Energy Intensive Industry Rate hearing"*

MIPUG noted that under cross examination, MH indicated that effective June 23, 2005 there would be no allowance applied to any facilities required to serve new loads exceeding 30 kV or loads in excess of 5 MW, without the approval of the MH's Executive Committee

MIPUG noted that MH Exhibit #10 indicated that three customers were affected by the change in policy, and MIPUG contended that the suspension of the former policy has resulted in unfairness and discrimination both among customer classes and between individual customers in Manitoba.

MIPUG advised that, given the limited information filed by MH on the Service Extension Policy and how it has historically been applied, the Board cannot be certain that, in its current Application, the policy is not applying separate principles to GSL>30 customers that did not exist prior to the unilateral suspension of the previous policy. MIPUG noted that under the new policy, MH's Executive Committee will establish separate charges for individual GSL>30 customers and that individual customers will have to make "separate deals" for service extension.

MIPUG held that the current policy is not transparent and lends itself to charges of unfairness and discrimination with regard to its application, as the terms of the policy are not clearly set out and approved by the regulator, and the application of the policy is entirely determined by MH, with decisions that occur “behind closed doors and beyond the scrutiny of the public”. MIPUG noted that as matters currently stand, the policy and its application could be subject to change without notice.

MIPUG contrasted this approach with BC Hydro’s TS6, which was reportedly approved by the BCUC after a negotiation process between BC Hydro and its affected customers. MIPUG noted that the public document, which is part of approved rates in British Columbia, is easily understood by the utility’s customers.

MIPUG stated that the Board has jurisdiction over the approval of MH’s Service Extension Policy, citing both legal jurisdiction through its governing legislation as well as its past practices, and noted that MH has been required to apply to the Board and seek approval (including approval of any changes) of terms and conditions attached to both the CRP and the Surplus Energy Program.

MIPUG noted that MH has not sought the Board’s approval for its unilateral suspension of the Service Extension Policy, and consequently no Board approval should be granted in this proceeding. MIPUG recommended that the Board direct that the Service Extension Policy suspension be reversed, and ensure that MH incorporates the Service Extension Policy into a publicly-available approved rate schedule for each class.

MIPUG submitted that should MH wish to suspend or change the existing Service Extension Policy, it is clearly required to make an application to the Board for its review and approval. Since MH unilaterally suspended the policy without proper approval, MIPUG recommended that the Board consider ordering

MH to refund amounts paid by customers where these amounts were in excess of the amounts that should have been charged under the policy.

MIPUG recommended that the Board reject the EIIR proposal for the following reasons:

1. MH has failed to support the basic need for the rate;

2. MH has failed to provide the Board with the analyses requested and the proposal simply does not address key issues or concerns raised by the Board in order 116/08;

3. Key regulatory principles are compromised by this proposal. The EIIR proposal is inappropriately discriminatory at its core;

4. There has been no review of options by MH, as requested by the Board;

5. There are non–discriminatory options available that would not require regulatory principles to be compromised; and

6. There are no precedents available for what MH proposes in its application.

7.2.5 Options

With respect to large new or expanding domestic load, MIPUG recommended that a Service Extension Policy, consistent with regulatory principles, should be developed for approval by the Board, which would, on a principled basis, establish the requirements for large load to pay relevant system – related costs incurred for connection.

MIPUG further stated the objective of such a policy should be specifically directed not to involve revisiting the EIIR approach and should not involve any impact on embedded cost rates, nor involve any compensation for lost export revenue or future energy related costs, but should address each new load on a separate basis without aggregation with a customer's other loads.

Mr. Ostergaard recommended that the PUB make electricity policy in the public interest, not just in the interest of ratepayers. Care needs to be exercised in trying to avoid choosing winners and losers and singling out new or existing customers for special treatment. To manage efficiency with an embedded cost structure, the Board should consider looking at implementing stepped rates. Mr. Ostergaard further noted that the current application takes the Board down a different path, asking them to decide who should be detached from embedded cost rates, rather than being asked to find a way to send price signals to all users.

With respect to new loads, Mr. Ostergaard recommended that the Board consider a standard form facilities agreement similar to TS6, which is meant to address specific concerns regarding costs to connect new industries. The current application is asking the Board to follow a different 'path', one where the Board is being asked to treat new industries interested in locating and investing in Manitoba in a completely different way than the industries that are already located in Manitoba.

MIPUG further stated that this alternative should only be brought forward to the Board after a Board-sanctioned consultation process, in which MIPUG believes that the Board's advisers should actively take part. Further, MIPUG suggested that issues concerning general load growth in the large industrial class, the issue of efficiency, and efficient price signals, should be reviewed in detail by the Board after meaningful and effective consultations with all stakeholders has been undertaken.

7.3 RCM/TREE

7.3.1 Sustainable Development

RCM/TREE stated that its intervention was based on principles of sustainability and justice. Sustainability includes durable economic well being as a component of social and environmental well being. RCM/TREE noted that MH is subject to the principles of *The Sustainable Development Act*, including the efficient use of resources; this means:

(a) Encouraging and facilitating development and application of systems for proper resource pricing, demand management and resource allocation, together with incentives to encourage efficient use of resources; and

(b) Employing full-cost accounting to provide better information for decision makers.

Based on these guidelines RCM/TREE stated:

1. Most customers should face marginal cost pricing for a portion of their load;

2. Generation, conservation, consumption and pricing decisions should be guided by full-cost accounting for all customer classes;

3. All customers should face similar constraints on consumption;

4. Customers should pay for only the incremental costs that they impose on the system; and

5. Subsidies should be applied in ways that do not undercut marginal cost pricing.

RCM/TREE recognized that MH is a key engine of prosperity in Manitoba and that the core of MH's business is the creation, delivery and sale of its premium product: reliable, storable, dispatchable hydroelectric power.

RCM/TREE cited MH's positive operating attributes of adjustable output and storage capacity which allows it to match variable market demand and prices and make feasible and economic other clean (but intermittent) sources of power like wind and solar.

This capability, to fill the supply void in those non-dependable renewable energy sources expands the potential for production of green electricity in Manitoba and export markets, to displace fossil fuel generation. RCM/TREE further suggested that, on the near horizon, MH will be called upon to meet demand for electrifying a growing portion of the province's transportation fleet, as plug-in hybrids of electric vehicles become more prevalent.

RCM/TREE stated that it is important not to waste MH's high-value commodity, but to use it efficiently. However, current domestic pricing undervalues the hydroelectric resource, hides the costs of growing usage and thereby encourages it, making conservation and self-generation efforts less cost effective, undermining the efficient use of electricity.

Mr. Chernick, who appeared as a witness on behalf of RCM/TREE, stated that domestic consumption of electric energy results in environmental costs, including the emission of additional greenhouse gases from the burning of coal and natural gas in power plants. To the extent there is greater clean hydro electric energy used in Manitoba, less is available for export to displace fossil generation of electricity (which emits more carbon dioxide).

7.3.2 The Problem

RCM/TREE stated that the current EIIR proposal is a recognition that growing electrical load comes with real costs, and that the cost for all users is increased by policies and pricing that lead to the inefficient consumption of electricity.

RCM/TREE indicated that load growth is the material issue and that in Hydro's forecast for energy usage for 2010/11, 75% of the energy use increases relate to customers over 30 kV, and that for 2013/14, 80% of the increase is again due to customers at or over 30 kV. In contrast, non-GSL customers represent 10% of the forecasted load growth increase in 2010/11, and 7% for 2013/14. RCM/TREE further noted that load growth has the potential for producing a negative impact on MH's finances.

7.3.3 Marginal Cost Rate

RCM/TREE supports MH's proposal to introduce an inclining rate for large industrial users. One of the key principles of inclining rate structures is to send price signals to industry to adopt DSM measures that reduce energy usage.

RCM/TREE rejects MH's proposal to utilize historic market prices (established in 2007 and 2008) in the determination of the second block rate for the next two to three years.

RCM/TREE recommended that the second block rate should be a forward-looking calculation, to reflect a more accurate value of the cost to Manitoba Hydro of supplying energy that would fall into the second block.

RCM/TREE recommended that the second-tier rate should be set on the basis of Wuskwatim's costs, but that in future proceedings, market-based marginal cost should be reported as well.

Mr. Chernick suggested that the second block rate could be based on recently-forecast Wuskwatim-in-service costs. These costs are expected to be 7.2¢ per kW.h for the GSL> 100 kV, and 7.4¢ per kW.h for the GSL 30 kV to 100 kV customer classes. Based on MH's projection of market prices, the second block rate would be 6.58¢ per kW.h for GSL> 100 kV customers, and 6.71¢ per kW.h for GSL 30 kV to 100 kV customers.

7.3.4 Constraints

RCM/TREE further contested MIPUG's claims that the transmission lines to other regions are fully loaded in most peak hours, so that MH can sell exports only in the low value off peak period. An analysis put forward by Mr. Chernick suggested that operational capacity existed on the transmission lines for additional on-peak sales under most circumstances.

As confirmed by MH, Mr. Chernick apparently reached his conclusions based on tie line constraints on net electricity flows relative to the maximum theoretical limit, rather than the scheduling limits of the system.

7.3.5 Growth Allowance

RCM/TREE stated that there's no compelling evidence to justify the growth allowance that is proposed. If the electrical usage is increased by the maximum proposed, the cost to MH is significant.

Mr. Chernick indicated the potential subsidy that will result from allowing for the growth allowance would be $4.5 million in 2011, growing to $34.5 million by 2018, and that would result in a revenue opportunity cost of $49.6 million annually by 2022. RCM/TREE recommended the elimination of the automatic growth allowance, in order to encourage companies to take effective steps to reduce energy consumption.

RCM/TREE also recommended that MH restate the demand charge as an increased on-peak energy charge, as this would provide more efficient pricing signals. This would result in different TOU prices for the heritage rate being applied to the GSL>30 customers.

RCM/TREE recommended that MH should phase-in MC rates for other customers in future applications, and put other GSL customers on notice of their upcoming transition to marginal cost rates.

7.3.6 The Baseline

RCM/TREE proposed that the first block baseline for each customer should be set at 95% of the CBEL, to increase the number of customers facing the higher second block rate. RCM/TREE further suggested that the Board gradually reduce the CBEL, to ensure that most customers will face marginal-cost prices and incentives for at least a small portion of their usage.

RCM/TREE recommended that the Board direct MH to file appropriate analysis and supporting data for a formula to be set on this basis, with alternative scenarios showing the CBEL decreased by various percentages from the original base.

With respect to DSM credits RCM/TREE stated that adjustments for previous Power Smart investments are appropriate in fairness to early adopters. However, DSM measures should not last forever, and early-adopted measures may, over time, become standard practice.

RCM/TREE recommended that full credit be given to savings from DSM measures adopted in the last 10 years in the determination of the CBEL. Any older DSM measures should be subject to verification that they remain effective and that they go beyond current standard practice.

RCM/TREE also did not agree that a credit should be given for energy efficient solutions for environmental compliance, indicating that ordinary environmental compliance is an internalized cost of doing business.

7.3.7 Economic Development

RCM/TREE questioned the subsidy resulting from the growth allowance (approximately $49.6 million annually by 2022), suggesting that a portion of the revenue raised by the second block rate would be better used by the Province of Manitoba to subsidize economic development.

7.4 MKO

MKO neither attended nor provided cross-examination at the EIIR hearing. However, MKO submitted a written argument dated January 20, 2009 for inclusion in the transcript of the proceeding.

MKO stated that the design of rates for all customer classes must address the issue of imbedded cost rates being significantly lower than marginal costs, and not just through the design of the unique rate to apply to those customers within that GSL class for forecasting significant load growth.

MKO cited the recommendations it made at the 2008 GRA:

> *“MKO suggests that properly-designed inverted rate structures could accomplish the goals MH is trying to achieve with its proposed energy-intensive rate design and that MH should propose such rates for all customer classes in the next proceeding. As noted by MH, the hydroelectric generation built in Manitoba provides more than economic benefits, it also provides "quality of life" benefits.*
>
> *Inverted rates must reflect an appropriate trade-off between providing the appropriate level of "quality of life" benefits and maximizing the economic value of MH's generation capability. In this regard, MKO further recommends that the Board order that the application of any inverted rate structure for any customer class must be accompanied by universally available and practically-accessible DSM programs that are provided by MH on a turnkey basis, as recommended by Mr. Dunsky."*

MKO stated that rate making decisions, including those related to the proposed EIIR, must consider and incorporate broader societal values and goals such as quality of life and economic expansion of industry.

MKO stated that the central objective ought to be ensuring that the water power resources of Manitoba, and electricity generated by the development of these resources, must achieve maximum value and benefits for Manitobans and, in particular, for those Manitobans adversely affected by MH's projects and operations.

MKO submitted that the appropriate party to make a determination of whether the maximum value and benefits for Manitobans are being achieved is the Province of Manitoba, in close consultation with First Nations that have been affected by hydro development, MH's customers and stakeholders. MKO cited sections 18.2 of the Northern Flood Agreement of 1977.

> *"Canada and Manitoba recognize that 'the Project is intended to benefit all citizens of Canada, and most particularly of Manitoba,' on the one hand, and that the resource users have been and may continue to be adversely affected on the other hand, and that 'it is in the public interest' to ensure that any damage to the interests, opportunities, lifestyles and assets of those adversely affected be compensated appropriately and justly."*

MKO also asked the Board to take judicial notice of Article 18.4 of the Northern Flood Agreement, which further assures:

> *"18.4 The Project affects the activities and traditional lifestyles of the communities and anxieties have developed regarding the viability of the communities, the free and safe use of the waterways, and 'the continued opportunity to carry*

> *on traditional activities, particularly as they relate to the wildlife resources as a source of food, income-in-kind and income.' These anxieties may be allayed by Hydro, Manitoba and Canada using their best efforts 'to ensure that potential benefits of the Project are made available' in a practical manner to the residents of each Reserve."*

In making determination a public policy, MKO submits that Manitoba owes a duty to the First Nations affected by MH'S projects and operations to ensure that maximum value and benefits is being achieved. MKO First Nations are both customers of MH and historic capital investors and "shareholders" in the development of Manitoba's water power and ought to be directly engaged in any discussion of significant changes in Manitoba's Energy policy or in the financial, operational and rate setting policies of MH, including in respect of ensuring maximum value and benefits from the sale of electricity to domestic customers.

In respect of the proposed EIIR, MKO adopted the analysis and recommendations made by the Coalition. MKO supports the Coalition's recommendation that the Board direct MH to defer the consideration of the EIIR, pending a needs and alternatives analysis.

MKO agreed with the Board-approved December 31, 2007 date for determining the baseline load for the purposes of any EIIR. MKO recommended that the EIIR include an appeal mechanism in respect of customer baseline loads.

MKO also recommended that an appropriate Service Extension Policy be developed to accompany any future EIIR, in order to address the potential for disproportionate cost of load expansions by GSL customers.

MKO suggested that the Board should request and receive the explicit endorsement of the Province of Manitoba for any proposed EIIR prior to approving any such rate.

MKO recommended that the Province and MH engage hydro-affected First Nations in a broad public policy initiative, to be conducted under the auspices of the Board and to consider public and economic development policy and rate setting matters.

8.0 Presenters

8.1 Mr. Sarafolean

Mr. Mike Sarafolean is the Regional Energy Manager of Gerdau Ameristeel ("Gerdau") and is responsible for 13 steel mills in North America. He is also the chairman of the Minnesota Chamber of Commerce Energy Committee. Gerdau is the second largest customer of Xcel Energy Inc., in Minnesota.

Mr. Sarafolean pointed out that Gerdau, one of Manitoba's largest manufacturers, employs 570 people in Selkirk, and provides contract work to 50 full-time equivalent local contractors. In addition, he stated that Gerdau has also over the years attracted several downstream manufacturers to locate in Manitoba, in order to be closer to the supply of steel, and that Gerdau also provides collateral jobs to its suppliers. He stated that Gerdau has invested $125 million in Manitoba since 1995.

Mr. Sarafolean indicated that Gerdau supports the positions taken by MH to encourage reasonable industrial growth allowances at heritage rates. He emphasized that the cost of electricity is second only to the cost of scrap steel, and that low, stable and reliable electricity is essential to Gerdau's operations in Manitoba. The Manitoba plant has the company's second highest cost to produce steel, and he is concerned about the effect that an increase in electricity cost will have on the plant's overall viability.

Mr. Sarafolean stated that Gerdau can work with MH's energy-intensive rate proposals, as it will still allow them to grow the Selkirk plant economically. They are opposed to inverted rates for industrial users, as they cap or penalize additional production, rather than encourage full utilization of Gerdau's installed capacity. He also indicated that Gerdau is opposed to Time Of Use (TOU) rates, since their industry must operate on a 7 days by 24 hour basis, and has little ability to switch to off-peak hours.

The Presenter recommended that the PUB eliminate, or at a minimum, reduce the April rate increase, in light of the current economic downturn.

8.2 Mr. Schroeder

Mr. Wayne Schroeder is the Chief Power Engineer of Vale Inco Limited.

Mr. Schroeder stated that Vale Inco makes a significant contribution to the Manitoba economy. He indicated that Vale Inco currently employs 1,630 people in Thompson, Manitoba. He also indicated that in 2008, the company also invested $214 million in capital improvements to its Manitoba operations. To put this in perspective, he observed that the value of nickel production in Manitoba in 2006 and 2007 exceeded that of the combined value of wheat and canola produced in Manitoba in those years.

Mr. Schroeder pointed out that the recent global economic crisis has affected Vale Inco to the extent that several aggressive measures have been implemented immediately to secure the long-term viability of the company. He noted that this crisis is a reminder that the nickel business is cyclical, and that it requires stability in its major input costs, including electricity, in order to sustain and grow the company.

Mr. Schroeder noted that Vale Inco is MH's largest Power Smart customer, and that they have incorporated the Power Smart program into the planning for capital projects and general operations, and he cited several examples. Mr. Schroeder observed that the Regulator's framework in the Province should provide recognition of work performed by firms who have proactively managed their energy load. He also elaborated on the contribution that Vale Inco has made to the development of Northern Manitoba and its First Nations people.

While Vale Inco supports the concept of providing access to additional cost-based power supply for incremental growth; it was this Presenter's view that growth limits provided in the EIIR proposal would not affect Vale Inco's future growth prospects.

8.3 Mr. Svidal

Mr. Kaare Svidal is the manager of the Energy Management Group of Enbridge Pipelines. His group procures electrical energy for the pipeline in 25 jurisdictions in North America. He stated that Enbridge has been a long-term, stable base load customer of Manitoba Hydro for 43 years.

Mr. Svidal indicated that Enbridge is concerned that the rate of $47.90 per megawatt hour filed by MH lacks any time-of-use, seasonal or real-time price signals. He stated that Enbridge can be price-responsive, and that efficient price signals encourage optimization and efficiency between customers and the utility. He stated that the proposed rate will create inefficiencies.

Mr. Svidal also stated that the marginal energy rate is not a true market rate, and he is concerned that customers will be unable to hedge any incremental consumption due to the lack of a visible market. He pointed out that the National Energy Board Export Permit (EPP 268) requires that MH offer domestic customers the opportunity to buy energy before it can export.

Mr. Svidal also indicated that Enbridge is concerned with the discriminatory nature of the rate and the precedent it may be setting. He pointed out that Enbridge has been a customer for 43 years, and that it did not suddenly move to Manitoba to take advantage of low-cost hydro-electricity. On the contrary, he explained that the pipeline is a captive customer of the MH monopoly.

8.4 Mr. Turner

Mr. Bill Turner is plant manager of Canexus (located in Brandon) and the Chairman of MIPUG.

Speaking on behalf of MIPUG, he indicated that low-cost electricity is necessary for industry to remain competitive in Manitoba, because it offsets existing geographic, climatic and other disadvantages of locating in this province, disadvantages that also include higher taxes and the US exchange rate.

Mr. Turner stated that fair rates (that reflect MH's costs) and diligent attention to ensuring these costs are as low as possible while maintaining a financially-healthy utility are an essential part of ensuring that Manitoba companies can continue to survive and grow. Low electricity prices are critical in maintaining and enhancing the long-term investments, jobs, and other benefits that come from having these operations in Manitoba.

Mr. Turner acknowledged that the current EIIR proposal would provide industry with some short-term certainty which is necessary for most members' five year planning horizons. However, he noted that the current proposal presents challenges for MIPUG as the effect on each member varies substantially, depending on the particular customer characteristics. As a result, each member will have unique, company specific perspectives.

Mr. Turner suggested that MH's proposal could discourage growth within Manitoba. While not all companies will be affected, for those that will, the potential adverse impacts arising from the rate will be felt by employees and their families, in the predominantly rural and Northern Communities where industrial users are located and where new industries tend to locate, as well as by the province as a whole.

With respect to Canexus, Mr. Turner explained that 60% of the firm's manufacturing costs are for electricity ($48 million annually). Reliable, cost-effective electrical energy is one of the most critical factors for the industry. Given the importance of electricity to the production process, efficiency is an important consideration. He stated that Canexus' entire production is exported, with 95% going to the US.

Mr. Turner indicated that when Canexus, as a complete multinational entity, is not operating at 100% capacity, production is shifted to the lowest-cost facilities. He noted that the Brandon facility was opened in 1968, and has grown into the largest sodium chlorate plant in the world. He stated that since the year 2000, the Brandon facility has undergone 3 major expansions at a cost of $200 million. He advised that the Canexus Board of Directors agreed to expansion in Manitoba on the strength of the Manitoba Government's commitment to stable and low hydro rates, and that these commitments are necessary for future expansion.

Mr. Turner cited numerous examples of initiatives between the company and Hydro to develop efficiencies, and in particular the Phase 7 design of the expansion in Brandon. Mr. Turner stated that he was led to believe that Canexus would receive the full benefit of these Power Smart measures, and that it now appears that it will not receive the full benefit due to the 1,500 gigawatt/yr cap. Mr. Turner suggested that the cap is discriminatory toward his company in particular, in that all new load for Canexus will be subject to marginal cost while, over the next 5 years, most of the other Hydro customers will be allowed to grow at embedded cost based rates. Mr. Turner expressed his disappointment that Hydro was not honouring the assurances they had given Canexus in this regard.

Mr. Turner indicated that Canexus could benefit from load-shifting or time-of-use rates, and he was disappointed that these have not been included in the current proposal.

Finally, Mr. Turner pointed out that the current economic crisis has already caused Canexus Brandon to scale back due to lost sales. He urged the PUB to be very cautious about the spring's rate increase, and the effect it will have on the Manitoba economy.

9.0 Board Findings

Short Term Issue

In basic terms and in the near term, MH has asserted that it can make more revenue by selling an extra kilowatt hour of energy on the export market rather than selling that same kilowatt hour of energy to a domestic customer, especially if that domestic customer is an industrial customer.

This situation has arisen because of MH's relatively low cost to generate hydro-electricity, and also because of the increased value of MH's exports. As annual net export revenues are used to subsidize the rates charged to domestic customers, therefore virtually all increased electricity consumption by Manitobans negatively affects MH's revenues, because, in the near term, energy to serve such domestic load increase is diverted from profitable export markets.

MH suggests that such revenue reduction could be more pronounced when large, energy intensive industries either undergo major expansions or locate in Manitoba, to capitalize on MH's low domestic electricity rates.

It follows that if net export revenues are reduced because more energy is sold domestically, rather than being exported, then Manitobans will be required to make up that revenue deficiency through increased domestic electricity rates. The average recovered cost of domestic bulk power is approximately 3.5 cents/kW.h, and the average revenue for energy exported is approx. 4.9 cents/kW.h.

To exemplify the issue (as MH has), and assuming a new large, energy intensive load (whether due to expansion of an existing business or a new business locating in Manitoba) of approximately 100 MW, MH's corporate revenue could be reduced by approximately $14 million annually, thereby necessitating a rate increase of approximately 1.4% to all domestic customers served by MH to recover the revenue deficiency as a result of foregone export sales.

Long Term Issue

MH previously estimated its marginal cost of generation and transmission to be in the order of 7.0¢/kW.h, levelized over twenty years. MH now forecasts its future export prices will increase dramatically, from current levels to about 12¢/kW.h, due primarily to the combination of higher costs for fuel and the introduction of carbon taxes or emissions limits (which would result in the internalization of carbon costs in the U.S. markets into which MH exports).

Virtually all new or expanded domestic energy load growth exposes MH to future costs greater than the expected incremental revenue to be received from such loads. However, due to its scale, large energy-intensive industry load growth, optically, has a greater impact on the need to advance new generation and transmission facilities, and on the reduction of surplus energy available for export.

Yet, in the current economic environment, the Board questions whether the threat of load growth is imminent, or has abated somewhat in Manitoba with the decline in the global economy. Perhaps the next load forecast will assist in providing the answer.

MH's EIIR Proposals

In both its last GRA and in the Special Hearing on EIIR, MH has advanced proposals whereby new and expanding energy-intensive industries requiring significant amounts of energy would be subject to various exemption criteria to determine whether or not such industries would pay a rate based on historic embedded costs (“heritage rate”), or pay higher rates based on marginal costs.

As will be discussed further, and in the Board’s view, aspects of MH’s EIIR proposal have merit, while other aspects of its proposal are not acceptable to the Board.

Therefore, and because MH’s EIIR proposal is not fully satisfactory to the Board, MH’s Application for an Energy Intensive Industrial Rate will be denied.

Rather, the Board will require MH to prepare a further application, based on the principles and directions of the Board, together with further consultations with stakeholders.

The Board, as it has been since this issue was brought to its attention, is also receptive to reviewing additional options to the Board’s directed approach - either from MH or from stakeholders.

The Board will expect MH to manage the continuing process of EIIR development and stakeholder consultation, and will expect MH to report to the Board setting out the proposed consultation plan in advance of undertaking the consultation. Any alternative option(s) that arise from the consultation with stakeholders should be presented to the Board together with MH’s recommended EIIR proposal.

Board-Directed Approach to EIIR

From a principled perspective, MH's low domestic rates may encourage more domestic consumption, rather than energy efficiency and conservation. Furthermore, MH's low domestic rates may attract new energy-intensive industry to Manitoba. Each of these circumstances would result in the reduction of MH's revenues, as profitable export sales are foregone. This revenue reduction is magnified when energy intensive industries increase consumption or locate in Manitoba.

Because GSL > 30kV customers include the most energy intensive, and because of available installed metering technology, the Board agrees that these customers (which fall into two sub classes of General Service Large) should be exposed to a new EIIR.

From a principled perspective, and rather than use various filters and screens to limit the applicability of an EIIR, all non-government GSL customers (served at 30kV and above) should be subject to a higher rate for certain load growth, above an existing baseline level.

The EIIR should not, at least initially, apply to federal, provincial, and municipal government accounts, nor to other public sector infrastructure such as water and waste treatment plants, hospitals, and schools. Conservation may require incentive, second tier rates to apply, at some point in time, to all customers.

The Board generally agrees with the MH proposal that load growth by the industrial sector should attract higher rates at or approaching the Marginal Cost of energy. MH's substitution of an historical proxy price for forecast export prices has merit. However, the Board questions the use of peak (5 x 16) export prices as the appropriate marginal costs proxy value for all industrial electricity consumption during the full 7 x 24 weekly periods.

Off-Peak Energy

The Board notes that it is widely accepted that energy sales of surplus, off-peak energy (weekends, holidays, and weekdays from 11:00 p.m. to 7:00 a.m.) on the opportunity export market does not, typically, recover the same prices as do on-peak exports.

For that reason, the Board does not support a marginal cost rate (or marginal cost rate proxy) being charged for domestic load growth during off-peak hours. Embedded cost rates should continue to be applied to domestic load growth during off-peak hours, as those rates provide better assurance of revenue neutrality to MH.

On-Peak Energy

The Board finds that the energy that has the highest export value to MH is that energy sold on-peak, which means Monday to Friday between 7:00 a.m. and 11:00 p.m. (also referred to as 5 x 16 power).

Domestic load growth that displaces profitable exports during on-peak hours will reduce MH's revenues. In the Board's view, an EIIR for on-peak domestic load growth will approximate revenue neutrality to MH, provided the proxy for the marginal cost energy rate is the average price of MH's extra provincial firm sales during the two year period prior to March 31, 2008 – as adjusted to remove the appropriate demand charge inherent in export prices.

On-Peak Baseline

The Board is of the understanding that appropriate metering technology is in place for the thirty-four customers in the GSL>30 kV sub-classes to support a Time of Use, On-Peak vs. Off-Peak rate tariff. Accordingly MH should establish on-peak energy baselines for each of the thirty-four General Service Large customers served above 30kV. The Board is also of the view that such on-peak energy baselines should be set at the maximum twelve consecutive month aggregated on-peak energy consumption for the thirty-six month period ended March 31, 2008.

The on-peak energy baselines should be adjusted for only:

- Non-made up load curtailment of on-peak energy under the Curtailable Rates Program;

- Load displacement under the Self Generated Energy option of the Surplus Energy Program; and

- Additional energy consumed by an energy efficient solution, other than fuel switching, which is required for compliance with, or in anticipation of, any federal or provincial act or regulation or government issued guideline with respect to environmental objectives.

If a customer can establish that unusual conditions applied during the entire thirty-six month reference period, an earlier period may be chosen to establish the initial on-peak baseline.

No other adjustments to the baseline are deemed by the Board to be warranted.

The Board believes that on-peak energy baselines calculated for individual companies should be aggregated with their Manitoba based affiliate companies. For customers with multiple accounts, on-peak energy consumption above their aggregated on-peak baseline will be calculated and billed to the individual electricity accounts proportionately, at the appropriate rate class, based on the annual on-peak energy consumption of the individual account.

Marginal Costs Proxy Rate

The Board accepts that historical firm export prices, averaged over the last two years, offer a reasonably stable proxy for the EIIR. These prices can, to a large extent, be verified by reference to information already in the public domain. Summary energy and price data supplied by MH, in addition to that from the Surplus Energy Program (SEP) and National Energy Board (NEB), does provide a strong and transparent correlation between MH's proposed EIIR prices and contract firm sales.

MH failed to provide an adequate in-depth analysis of the value of on-peak energy sales, compared to the value of off-peak energy sales, into the MISO Market. Additionally, no information was provided on the specific deferral values that could be achieved from constrained industry load growth. Relying entirely on export market prices to define marginal costs (rather than using deferral values) inhibits reconciliation with cost causation principles which, in the Board's view, must be addressed.

To set the second tier energy rate, MH has backed out a demand component (already being paid for by the customer) of 0.74¢/kW.h that assumes a load factor of 100%. However, the average GSL>30 load factor is 83%, and this suggests a 0.90¢/kW.h adjustment to the proxy price.

While the Board can accept the proxy for the marginal cost energy rate being the average price of MH's firm extra-provincial sales during the two year period prior to March 31, 2008, the Board's direction is to subtract a demand component of $0.90 to reflect the more typical export demand component of on-peak energy sales.

In the Board's view, the initial proxy rate should stand for a three-year period, to allow for a degree of stability and an adequate test period. That said, adjustments could be proposed in the event of unusual circumstances.

New Energy-Intensive Companies Locating in Manitoba

Only one new energy intensive industry has located in Manitoba in the past ten years and at the hearing, only one was speculated to locate in Manitoba in the next ten years.

However, when/if a new energy intensive industry does locate in Manitoba, it will expose MH and its current ratepayers to future costs of generation and transmission greater than the incremental revenue recovered from such new load.

The impact of large new energy-intensive firms, and the risks such may impose on MH's other customers, was the subject of the Board's commentary in its Order 177/06 in regard to MH's Cost of Service Study Methodology.

In MH's EIIR proposal, new-to-Manitoba energy-intensive companies would be entitled to up to 100 GW.h of annual energy consumption at embedded cost rates, with additional consumption being billed at the higher EIIR.

In this current hearing on MH's EIIR, the Board has been provided evidence as to how other primarily hydro-electric based jurisdictions are approaching the issue of new energy-intensive industrial customers.

Further analysis from MH is needed. However, the Quebec maximum appears more applicable to the limit that should apply to the Manitoba situation, rather than the British Columbia capacity limit.

The Board will direct MH to revise and file its Service Extension Policy so as to include provision for new-to-Manitoba energy-intensive industrial customers being subject to a limit or cap on available generation capacity, above which limit a customer contribution toward Generation and Transmission costs would be required, the amount to be based on a to-be-developed financial feasibility test.

On the current evidentiary record, the Board has not, and is unable to, reach a conclusion, and can provide only directional advice at this time respecting what on-peak annual energy consumption level, if any, should be made available at embedded cost rates to new energy intensive industrial companies locating in Manitoba.

The Board will expect options, supported by reasons and financial analysis, from MH and stakeholders.

Board's Detailed Review of MH's EIIR Proposal

MH's response to Board Order 150/08 (Directive 29) was to file an updated EIIR application that eliminated the economic benefit tests for EIIR exemptions. Such economic benefits were the subject of much discussion and concern by Interveners at the last GRA. MH substituted an EIIR exemption process based on prior years' consumption levels. Above those consumption levels, all load growth (with some further exceptions) would be billed at a higher EIIR, reflective of the marginal cost of electricity.

MH's EIIR evidence has given the Board a reasonable understanding of the industrial sector's use of energy and the variability of the industry sector's demand on MH's resources. The Board notes that most of the forecast industrial load growth is attributed to four or five customers. MH has provided one EIIR proposal for the Board's consideration, and no options were presented by MH, even though discussions with stakeholders suggested only a limited consensus and some desire for other approaches.

Evidence at the hearing indicated that MH's proposed EIIR was targeted to limit the number of customers to be actually affected by the new rate. This runs counter to the Board's Directive (No. 29(c) of Order 150/08) to examine a broader scope of GSL >30 customers, with a view to lowering the threshold and extending the EIIR impact to more customers.

The Board believes a broadly-based, two-tier rate system would add substantially to energy conservation in Manitoba. By exposing all energy-intensive industries to a higher rate for on-peak load growth, there will be an incentive (and a reasonable price signal) to promote energy efficiency and conservation for all industrial customers served at and above 30 kV .

The proposed EIIR targets only a limited number of customers (which are essentially captive loads) and does not provide any significant incentive for any energy conservation by GSL >30 kV customers as a whole.

MH's EIIR Application failed to address the long-standing directives (most recently, Directive No. 22 of Board Order. 150/08) on Time-Of-Use (TOU) rates. Given that appropriate meters are already in place, the Board noted in Order 150/08 that with the limited number of customers subject to EIIR, it should be neither onerous nor cost prohibitive to incorporate TOU rates.

It is the Board's view that TOU is integral to the acceptance of MH's EIIR proxy price. The oft-cited export price differential of 3¢/kW.h between peak and off-peak periods supports the contention that TOU be recognized in the EIIR design process.

The Board would further suggest that because MH's export contracts primarily target on-peak (5 x 16) time periods, the highest value of conservation efforts by industrial customers should fall within the same time period. The EIIR should reflect this TOU reality, and not be heavily focused on increasing MH's industrial class revenue.

MH's evidence suggests that the EIIR is revenue-neutral if all energy-intensive industry load growth consumption could be converted to on-peak period export sales. The Board concludes that, in the absence of TOU prices in the EIIR, revenue neutrality is highly unlikely. The Board finds revenue neutrality for MH to be an essential component of the EIIR design.

MH's application did not address Board Directive No. 28 from Order 150/08 on the use and suspension of the Service Extension Policy. Oral evidence provided limited insight for MH's unilateral decision to suspend this Policy. Consequently, the Board is faced with directing MH, in consultation with stakeholders, to advance a revised Service Extension Policy, possibly similar to BC Hydro's Tariff Supplement No. 6.

MH's EIIR Application as filed, and as supplemented by evidence at the Hearing, leads the Board to express the following comments and concerns:

a) MH's objective from the Cost of Service Study Hearing has fundamentally changed, from limiting the entry of new industry into Manitoba, to restraining industrial load growth within Manitoba.

b) MH's EIIR targets a limited number of industries that have grown rapidly in the last eight years, and for which MH forecasts a continuation of that growth. However, in light of the current economic downturn, there is a strong possibility that much of this growth will now be deferred and MH's next load forecast may well show much slower growth.

c) The EIIR exempts most GSL >30kV industrial customers from the new higher rate by providing growth allowances, full prior DSM and Power Smart credits, or threshold exemptions. These will shield all slow growing and non-growing companies from the EIIR and act as a disincentive to conservation and energy efficiencies.

d The EIIR does not distinguish between on-peak and off-peak growth; some customers could employ the growth allowance entirely during peak periods thereby creating greater pressure for new generation and transmission capacity.

e) The "hard" cap on an industrial company's consumption (to be billed at 'heritage' rates) is focused on MH's largest customer. There was no evidence that one large company's growth has greater generation and transmission consequences than the growth of several smaller companies with the same aggregate energy growth.

f) The EIIR (as proposed) is not revenue neutral for MH; charging on-peak rates for off-peak energy runs counter to the EIIR objectives of offsetting export revenue loss due to domestic consumption and, as well, the principles of fairness to domestic industry.

g) MH's export contracts guarantee 5 x 16 capacity and also appear to provide the counter party (customer) with assured access to MH's surplus off-peak energy at prevailing off-peak market prices. The Board understands that to export 5 x 16 firm energy requires more generation capacity, and also requires MH to employ its reservoir storage system to shape and form river flows to a much greater degree than for domestic industrial load. The Board views this as providing exports with a "superior product" compared to domestic industry.

h) MH's contention that all domestic industrial energy displaces peak exports appears to the Board to be correct only about one-third of the time. Constraints such as hydraulic generation capacity, transmission tie-line capacity, adequacy of river flows/energy-in-storage and market receptivity all tend to limit MH's ability to achieve on-peak export prices.

i) MH's proposed proxy for marginal cost is not entirely transparent, despite MH's initial contention that the average export prices could be verified by reference to publicly available information such as SEP/NEB/MISO reporting systems. It now appears that the publicly-reported information as to firm export prices is further clouded by financial settlements of export agreements, energy trading activities and supplementary off-peak sales.

j) Tying the proposed EIIR to actual average on-peak export prices should not be taken as a precedent for establishing EIIR levels for future domestic industry's new energy usage. In the Board's view, the marginal cost proxy for the EIIR may require further exploration in advance of any escalation.

k) MH's planned new major generation and transmission projects (Bipole III, Keeyask, Wuskwatim, and Conawapa) may, in aggregate, result in average energy output costs in the order of 12¢/kW.h; but the Board has received no assurances that the pending new export contracts (Wisconsin Public Service, NSP/Xcel Extension, and Minnesota Power) will achieve peak energy prices at or above that level.

It is the Board's view that if industrial load growth is to attract Marginal Cost rates, then export sales should also reflect Marginal Cost. Lower-than Marginal Cost export prices could mean domestic customers' rates will be subsidizing these export sales.

l) MH's unilateral suspension of the Service Extension Policy has not been adequately justified, and the resultant policy vacuum does not serve the interests of consumers, including those industries considering locating in Manitoba.

m) MH's suggestion that EIIR revenues be treated as a separate line item in the Cost of Service Study, with costs arbitrarily set equal to revenue, appears without merit. Such treatment would essentially avoid defining Marginal Cost on an appropriate transparent cost causal basis.

n) MH's pending export contracts require a commitment of most of the firm energy that will flow from the in-service of Bipole III, Keeyask Generating Station, and Conawapa Generating Station. These generating stations constitute approximately 50% of MH's remaining and untapped hydraulic generation resources. In the Board's view, the contract prices for these export sales are crucial to MH's long-term financial viability and as such, 5 x 16 export contract prices must be greater than MH's forecast average export prices. MH has yet to confirm the financial terms of on-peak exports, or to define future values of off-peak energy sales which now are typically less than one-third of on-peak energy prices.

Based on the Board's findings, MH's EIIR Application, as filed, would assure MH of revenue gains at the expense of a select few customers. The targeting of a select few industrial customers does not adequately reflect the impact of overall load growth on the future need for generation and transmission capacity.

Consequently, the Board will deny MH's EIIR application as submitted.

Through this Order, the Board provides specific direction and seeks MH's consultation with Stakeholders in order to prepare appropriate alternative industrial rate scenarios. On the basis of the evidence provided in the EIIR hearing process, the Board has concluded that a revised EIIR proposal must send a broader price signal. Therefore, the Board has outlined above one alternative scenario to be considered and further developed by MH in consultation with Stakeholders.

In light of apparent slowing of industrial growth over the last two years, the previously suggested urgency of an EIIR has faded. The Board has concluded that MH's EIIR, as submitted, should not be approved.

The Board agrees with Interveners who have suggested that MH undertake further consultation with stakeholders in an open process. This process would look to achieve industry/utility consensus on a new EIIR, but failing that, alternative EIIR proposals should be submitted for Board consideration along with the proposal that the Board has requested and noted in the Conclusions section of Board Findings.

In rejecting the EIIR proposal as submitted by MH, the Board concludes that the achievement of energy efficiency and conservation are an essential component of this industrial rate adjustment. As such, all GSL >30 customers should be exposed to the higher second tier rate for the on-peak portion of their load growth.

The combination of growth allowances and past DSM/Power Smart credits excludes too many customers from efficiency price signals, and should be eliminated. Those customers have already and continue to receive the benefits of their investment.

The Board also holds the view that an absolute cap on an individual company's energy consumption is not appropriate. However, a capacity limitation or cap on a company's growth (such as to trigger a requirement for customer capital contributions for generation and transmission) within a new Service Extension Policy would limit MH's and domestic customers' exposure to impacts of large new loads.

The Board is of the current view that new industry coming to Manitoba should, at some point, be entitled to an historical baseline and a degree of relief from the EIIR. One conceptual approach, among others that may be developed and considered, is that initially the on-peak energy baseline should reflect no more than 50% of the maximum anticipated customer on-peak energy demand, as averaged over the initial three years, and then be adjusted to some fraction of the average of the last twenty-four months of actual on-peak energy demand, following the third year.

Conclusion

To assist MH and Stakeholders, the Board requires the development of one scenario that incorporates the following provisions:

- applies to all non-government GSL>30 customers;
- EIIR only applicable to on-peak load growth above an existing aggregated baseline;
- baseline adjustments will only be permitted relative to Curtailable Rates Program; Self-Generation and mandated energy efficiency;
- proxy rate of 5.53 cents/kW.h adjusted downward by 0.9 cents/kW.h to remove the demand component, to apply for the initial three year test period;
- new to Manitoba GSL>30 customers are entitled to 50% of on-peak energy at embedded cost rates, for a period of three years, after which an adjustment may be made;

Having laid out this particular scenario (or set of conditions), the Board is also open to alternative scenarios developed by MH and/or Stakeholders. The Board expects MH, in consultation with Stakeholders, to develop and submit additional alternatives that also reflect the Board's minimum requirements of:

a) Broad application of the EIIR to the load growth of all or most GSL >30 customers;

b) Time of Use pricing for on-peak and off-peak usage;

c) Options, with recommendation on approach, to dealing with new to Manitoba industry entrants;

c) Contributions to generation and transmission costs for load growth above a defined MW demand level; and

d) A compatible Service Extension Policy.

10.0 IT IS THEREFORE ORDERED THAT:

1. MH's September 30, 2008 Application for a new Energy Intensive Industrial Rate BE AND IS HEREBY DENIED.
2. MH file on or before July 31, 2009, for the Board's review and comment, the Stakeholder Consultation Plan.
3. MH file by November 30, 2009, for Board review and approval a revised General Service Large >30 kV Energy Intensive Industrial Rate proposal as directed in this Order, together with any further scenarios MH and/or Stakeholders want to be considered by the Board.
4. MH file by November 30, 2009 for Board review and approval, a new Service Extension Policy that incorporates the capital credits available to offset basic sub-transmission and distribution upgrade charges, and required capital contributions toward generation and transmission costs for set MW load additions of, say, more than 30 or 50 MW, based on proposed parameters which are on a compatible basis with the new EIIR Terms and Conditions.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE, CA"
Chairman

"GERRY GAUDREAU, CMA"
Secretary

Certified a true copy of Order No. 112/09 issued by The Public Utilities Board

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Secretary

11.0 Glossary

I Units of Measurement

Demand represents the size of electricity load over a specific period of time. It is typically expressed in:

- Watts (W)
- Kilo-watts (kW) - 1,000 watts
- Mega-watts (MW) - one million watts
- Giga-watts (GW) - one billion watts

for billing purposes, it may be defined on a monthly basis as:

- Vole-amperes (VA) - usually nearly equal to watts
- Kilo-volt-amperes (kVA) - 1,000 volt amperes

Energy represents the electricity provided to customers to do work or create heat, light, or sound. It is typically expressed as:

- Kilo-watt hours - 1,000 watt hours
- Mega-watt hours - 1,000 kilo-watt hours
- Giga-watt hours - one million kilo-watt hours

II **Load**

Customer classes are defined as:

- Residential (no demand billing)

- General Service Small (GSS)
    - No demand billing (GSS-ND)
    - Demand (GSS-D)

- General Service Medium (GSM)

- General Service Large (GSL)

    - 75 V to 30 kV (GSL <30)
    - 30 K to 100 kV (GSL 30-100)
    - Greater than 100 kV (GSL >100)
    - Greater than 30 kV (GSL >30)

Energy Intensive Industrial Rate (EIIR):

- Represents a new rate on energy consumption that MH proposes to charge to GSL 30-100 and GSL >100 industrial customers using in excess of 100 GWh/yr.

Customer baseline energy level (CBEL):

- Defines the historical energy consumption of GSL >30 customers (determined on the basis of most recent two years) that will be exempt from the EIIR.

Demand side management (DSM):

- Reflects reduction in demand or energy consumption achieved by consumers working with the utility on a subsidized (Power Smart) or unsubsidized basis.

III Price Issues

Proxy Price

In this Order, a "proxy price" reflecting the average firm export contract prices over the last two years is substituted for the marginal cost of electricity so as to avoid public disclosure of commercially sensitive or confidential information.

Marginal Cost

Reflects the value of demand and energy as derived from new Power Resources required to satisfy incremental growth in consumption.

<u>New Power Resources</u> can include:

- New generation and transmission assets.
- Increased thermal plant output.
- Wind energy purchases.
- Increased imports.
- Foregone exports.

<u>Exports</u>

Are achieved from electricity generated in excess of Manitoba's domestic needs and are sold to out-of-province energy markets in adjoining states and provinces.

<u>5x16 Exports</u>

Also known as peak period exports typically involve energy supplied between 7 a.m. an 11 p.m. on the five-week days. These can be contractually firm (guaranteed, even in adverse conditions) or opportunity (interruptible) sales.

<u>Off-Peak Exports</u>

Typically involve opportunity energy sales at all other times (not 5x16) on weekends and over-night.

Imports

Usually (but not always) involve the purchase of off-peak energy from utilities and/or market in adjoining provides or states to supplement domestically generated electricity and are typically derived from coal or natural gas-fired thermal generation.

Market Trading

Reflects externally purchased energy by MH (typically 5x16) resold by MH to external markets or utilities. There is no Manitoba generation energy involved.

IV Generation and Transmission

Generation is the conversion of mechanical energy usually by means of a rotating turbine driven by water, steam, or wind into electricity.

Hydraulic generation (hydro) involves the creation of electricity from river flows or water in the lake (reservoir) storage. This storage allows MH to convert (shape) off-peak energy supply into on-peak energy supply.

Thermal generation may employ coal as the fuel as is substantially done in the adjoining provinces and states, or may use nuclear fuel to create a constant flow of electricity.

Wind generation despite its variable/inconsistent nature is growing, with the reliance on hydraulic generation and natural gas thermal plants.

Transmission system consists of towers and conductors that transport electricity at 66 kV to 500 kV levels to local areas for distribution or to out-of-province utilities. A power grid is formed by interconnecting the various geographic legs of the system to ensure service even with localized outages.

Interconnections (tie-lines) are the power lines that lead into adjoining provinces and states allowing for electricity flow out of and into Manitoba. The capacity of these tie-lines can limit MH’s exports, particularly during the 5x16 periods.

V Evaluation

Full cost accounting involves the consideration of economic, environmental, land use, human health, social and heritage issues to ensure all costs and benefits (including externalized costs and benefits) are accounted for.

Environmental considerations include air, land, water, flora, and fauna within Manitoba geographic area and to some degree their relationship to their global aspects.