MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *The Public Utilities Board Act* (Manitoba)

**AND IN THE MATTER OF the Manitoba Hydro filing
in respect to the Cost of Service Methodology Review**

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

**WILLIAM HARPER, ECONALYSIS CONSULTING SERVICES
on behalf of The Consumers' Association of Canada (Manitoba) Inc./
Manitoba Society of Seniors (CAC/MSOS)**

**PATRICK BOWMAN AND ANDREW MCLAREN, INTERGROUP CONSULTANTS, INC.
on behalf of The Manitoba Industrial Power Users' Group (MIPUG)**

**JIM LAZAR, CONSULTING ECONOMIST
on behalf of Resource Conservation Manitoba and Time to Respect Earth's Ecosystems (RCM/TREE)**

April 27, 2006

Manitoba Hydro

MANITOBA HYDRO
COST OF SERVICE METHODOLOGY REVIEW 2005/06

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REBUTTAL EVIDENCE

<u>Introduction</u>

On March 15 and 16, 2006, Manitoba Hydro received pre-filed evidence from three intervenors in the current Cost of Service Methodology Review proceeding. Evidence was provided by:

- William Harper, on behalf of the Consumers' Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors (CAC/MSOS);
- Patrick Bowman and Andrew McLaren on behalf of the Manitoba Industrial Power Users' Group (MIPUG); and
- Jim Lazar on behalf on Time to Respect Earth's Ecosystems and Resource Conservation Manitoba (RCM/TREE).

Intervenor witness responses to Information Requests were received on or about April 13, 2006. Manitoba Hydro has reviewed both the pre-filed evidence and responses and herewith provides its Rebuttal Evidence which addresses some of the issues and suggestions raised by the Intervenor witnesses.

The rebuttal evidence is organized below into the nine topics listed in the Table of Contents. In most cases each topic addresses the evidence of one Intervenor. Most of the evidence which opposes Manitoba Hydro's recommended cost of service methodology was provided by the witnesses for MIPUG; hence most of the topics address the evidence provided by the MIPUG witnesses. One topic, the Classification and Allocation of Bulk Power Costs, addresses the Intervenor evidence of both MIPUG and CAC/MSOS.

The MIPUG witnesses oppose most of the significant changes proposed in Manitoba Hydro's recommended approach. In general, the MIPUG witnesses appear to continue to support longstanding approaches to the classification and allocation of the cost of bulk power resources and continue to believe that it is appropriate to offset Generation and Transmission embedded costs with most, if not all, of the much higher unit revenues received from export sales. Adoption of the MIPUG witnesses' preferred methods would maintain approximately the current excess of marginal costs over domestic rates, a gap which is largest for large industrial customers. To the extent that the MIPUG witnesses are prepared to concede that some limited portion of net export revenues should not be returned to domestic customer classes on the basis of their use of the Generation and Transmission systems, they believe that this portion should be dedicated to a regulated rate stabilization fund.

The MIPUG witnesses also take the position that gaps between rates based on embedded costs (including export credits) and the marginal cost of supply can be wholly addressed by adopting an inverted rate structure. Manitoba Hydro does not agree. Inverted rates are helpful in providing a price signal based on incremental cost to incremental usage, but they cannot always assure that a significant portion of incremental usage faces marginal cost.

By contrast, the witness for RCM/TREE is supportive of strong measures that would reduce the gap between domestic rates and marginal cost, even at the ultimate cost of substantial rate increases for all Manitoba customers. Manitoba Hydro believes that the evidence on behalf of RCM/TREE helps illustrate some of the problems and issues that the cost of service methodology needs to address and that this evidence can be construed as supportive for the directional changes Manitoba Hydro is seeking in its Cost of Service Study. However, it would be premature to adopt some of the specific recommendations, particularly the inclusion of certain environmental costs not currently internalized by Manitoba Hydro, and the direct adoption of the marginal cost of Generation (without also addressing marginal costs for the other functions) into the class revenue requirement benchmark.

The witness on behalf of CAC/MSOS is generally supportive of Manitoba Hydro's recommended cost of service methodology, but has some reservations with respect to the classification of the Generation function and with respect to the lack of direct assignment of some costs to the Export classes. This rebuttal demonstrates that these reservations are largely unfounded and, where they may be reasonable, they can be readily addressed.

Concept of Cost for Rate Regulation

The witnesses for MIPUG state in their evidence that: "In Manitoba, under the current legislation, the system in place is regulated rate making based on cost – there is no provision for market pricing to domestic customers …" Do you agree with this statement?

Manitoba Hydro does not agree with the MIPUG witnesses that the utility and regulator are constrained from considering any concepts of cost other than embedded cost in determining just and reasonable rates and, further, Manitoba Hydro does not agree that there is no provision for market pricing to domestic customers.

Market based pricing is already offered to Manitoba Hydro's domestic customers through the Surplus Energy Program (SEP), a rate offering approved by the PUB in Order No. 90/00. SEP and its predecessor surplus energy rate offerings, going back to the Interruptible Dual Fuel Rate established in 1990, were designed to provide a potentially lower cost option to customers prepared to accept less than firm service and upon terms comparable to the terms offered to the export market. A restricted definition of cost to that of embedded cost would not have allowed such rate offerings.

The MIPUG witnesses have noted in their response to MH/MIPUG-3 that the SEP Program and its predecessors should be viewed as exceptions to the strict cost basis of rate design, apparently because "the customer elects to accept service that can be interrupted by the utility in accordance with market or other specified conditions." However, Manitoba Hydro is not aware of any legislation or regulatory directive that limits consideration of market pricing to offerings such as SEP.

The assertion of the MIPUG witnesses also fails to recognize that there are multiple accepted interpretations of the term "cost", including historic cost, marginal cost, avoided cost and replacement cost. In *Principles of Public Utility Rates*, James Bonbright discusses the many conflicting interpretations and notes that "a cost-based standard is subject to many different interpretations and that the interpretation which would best comport with any single objective of ratemaking is almost sure to be ill-adapted to the attainment of the other objectives" (page 113). Manitoba's legislators appear to have recognized the need to continually balance various objectives and refrained from imposing a definition of cost, instead electing to create a system of ratemaking allowing for the consideration of not only costs but also other relevant policy considerations.

Consequently, the PUB is empowered to look beyond strict historic cost considerations or past practices in determining fair and reasonable allocation of cost among customer classes or as a basis for just and reasonable rates. In particular, the PUB is empowered to consider such concepts as market based rates, or the treatment of export revenues inside or outside a cost of service study on bases other than those adopted to date.

Regulated Reserve Fund Proposal

Please comment on MIPUG's suggestion regarding the disposition of "excess" export revenues into a regulated reserve fund for the explicit purpose of rate stabilization:

MIPUG examines three possible treatments of such revenues, assuming that a decision can be reached on what counts as "excess":

Option A – Apply a portion of export revenue to pay down debt via a "regulated reserve fund" against future droughts.

This is MIPUG's preferred approach. The PUB would direct a portion of export revenues to be simultaneously used for the pay-down of Manitoba Hydro's debt and the build-up of reserves for the stabilization of rates in the event of drought. MIPUG suggests this reserve fund would have more regulatory protection than Manitoba Hydro's shareholder equity, and would help to modify the growth of the Corporation's debt during the upcoming period of new northern Generation and Transmission developments. MIPUG conceives that annual allocations to this reserve fund could be in the range of $50-$100 million per year.

Option B – Increase payments to the shareholder.

MIPUG acknowledges that some other Crown utilities make dividend-type payments to their respective Provincial Government, but points out that Manitoba Hydro's current debt/equity ratio would be too high for the legislation in many of those jurisdictions to permit such payments. For example, BC Hydro cannot make payments that would increase its debt ratio beyond 80%. The comparable limit for Hydro Quebec is a 75% debt ratio. Manitoba Hydro's debt ratio is higher than either of these thresholds.

<u>Option C</u> – Offer one-time rebates or other forms of payouts to customers.

While this practice has occasionally been followed in the case of Manitoba Public Insurance, MIPUG asserts that in the case of Manitoba Hydro such payments would be contentious, difficult to administer and of questionable merit.

<u>Manitoba Hydro's Position</u>

Manitoba Hydro agrees with MIPUG on the need to improve the Corporation's debt ratio to 75%. Manitoba Hydro's equity has historically been used to cushion ratepayers from the full financial effect of loss years caused by events such as drought. One of the reasons for the 75% debt ratio target is to ensure that future levels of equity will be adequate to address growing risks to rate stability.

Manitoba Hydro believes that regulation of a special reserve would not enhance the powers that the PUB already has with respect to protecting ratepayers. In approving rate increases, the PUB already has the ability to review all aspects of revenue requirement including current and projected equity levels, domestic load growth, operating and capital costs and net export revenues. MIPUG concedes that any diversion of export revenues to a special fund implies a rate level higher than that which would exist absent such diversion (see response to MH/MIPUG-11) at least until the reserve is drawn down. Therefore in ruling on any particular General Rate Application the PUB is exercising its power to direct the enhancement of reserves which have always been intended to protect customers from risk such as drought.

MIPUG also agrees (in its response to MH/MIPUG-4(e)) that “industrial rates in Manitoba have been stable and predictable since the beginning of regulation…” This supports the view that reasonable progress towards the Corporation’s existing financial targets is sufficient to maintain rate stability without any compelling reason for an additional reserve.

Finally, Manitoba Hydro does not believe that any purpose is served by designating a portion of net export revenues as the source of annual increases to equity balances. Equity is automatically increased when there is positive net income. Domestic revenues, as well as net export revenues, contribute to that bottom line. Each General Rate review requires judgment as to whether Manitoba ratepayers are paying a reasonable amount for their electricity based on overall current and projected revenues, costs and risks. Manitoba Hydro submits that the focus should continue to be on the contribution that each year’s revenue requirement makes to net income and hence to equity rather than on the unnecessary and complicated step of defining and allocating “excess” export revenues to a special reserve.

The issue of appropriate financial reserves should be considered independently from the issue of the appropriate treatment of net export revenues. The latter needs to focus on cost definition and other cost issues, as well as rate design criteria such as inter-class equity and efficiency considerations.

Entitlement to Low Rates Based on Existing Resources and Export Earnings

MIPUG’s witnesses have suggested that: “…the generation and transmission resources currently in place …represent the entitlements of ratepayers to attractive and stable electricity prices” and that export revenues have been integral to this approach (page 6, lines7-9). Does Manitoba Hydro agree that ratepayers are entitled to attractive and stable electricity prices based on the existing generation and transmission resources?

In a very general sense, Manitoba Hydro does agree that ratepayers are entitled to the benefits of Generation and Transmission put in place to serve them and the cost of these resources should be allocated to ratepayers on the basis of their use of the resources.

However, it does not follow, and Manitoba Hydro does not agree, that ratepayers are entitled to the increase in value of these resources on the basis of their current use patterns. MIPUG's position, that ratepayers are entitled to all, or most, net export revenues, allocated on the basis of their current use of the Generation and Transmission functions, essentially amounts to stating that any increase in the economic value of these resources should be credited on the basis of current use. This is clearly neither sound economics nor sound public policy.

An alternative conceptual framework for relating allocation of export revenues to "entitlement" would be to identify a share of the heritage resource to which each customer, or major customer group, is "entitled" and then providing them with the value of export sales on the portion of their entitlement which they **do not** use. This would reward conservation rather than use. Of course, it is difficult to translate this sensible concept into actual practice, but one way might be to define a baseline share of the entitlement with reference to a particular baseline period. Since MIPUG appears to accept 1996/97 as a suitable baseline year, it is used as a starting point in the following example.

The example is set out quantitatively in Attachment MH-1. Attachment MH-1(1) determines the energy entitlement share of each of the domestic classes based on their shares of domestic usage in PCOSS 1996/97. These shares are used to calculate their "entitlement" to energy in 2005/06 based on the forecast total generation of 32.6 TW.h. The fourth column of Attachment MH-1(1) shows the forecast 2005/06 energy use by each class. The last column shows the "unused entitlement", i.e. the 2005/06 "entitlement" minus the expected class use.

Attachment MH-1(2) performs the same calculations to determine the capacity "entitlement", the forecast use and the unused capacity "entitlement" for each domestic class.

In Attachment MH-1(3), the net export revenue allocation is undertaken by sharing the energy related component on the basis of unused energy "entitlement", and sharing the capacity component on the basis of unused capacity "entitlement". Note that one class has a negative 2005/06 capacity entitlement and therefore must pay into the net export revenue pool for its excess capacity usage. Note also that some of the net export revenues are preallocated to deal with specific policy issues related to uniform rates and sharing of export revenues in the diesel zone.

Finally, in Attachment MH-1(4), the net export revenue allocated on the basis of unused entitlement is factored into the determination of Revenue to Cost Coverage ratios. The RCC results are very different from either the current or recommended methodologies. In particular, those classes which have conserved the most of their entitlement have RCC ratios above 100% whereas those classes where load growth since 1996/97 has been greatest, fall below, sometimes significantly below, 100%.

Of course, while this example has some conceptual appeal, it may be perceived as unfair to customers on an individual basis. For example a longstanding customer in the General Service Large >100 kV class might be concerned that, no matter how much conservation effort it makes individually, its entitlement is being eroded by all those new customer loads and expansions that are utilizing the class' entitlement. But this concern would also speak directly to the issues of how entitlement is defined and who is included in this definition. Even without resolving those issues, however, it should be apparent that, in today's marginal cost environment, an allocation mechanism which rewards conservation is more appropriate than one which rewards increasing use. Manitoba Hydro's recommended approach to allocation of net export revenues is an attempt to at least expand the cost base on which they are allocated beyond simple consumption of energy and capacity.

An alternative allocation approach, which recognizes entitlement but is more neutral with respect to differing rates of growth in the loads of individual classes, could be constructed through a variant on the example shown in the evidence of Mr. Lazar, on behalf of RCM/TREE. Mr. Lazar's original Exhibit, JL-4, substitutes marginal supply cost for embedded Generation costs, sets all other costs equal to those in Manitoba Hydro's Recommended Method, and sets class RCCs equal to the class revenues at current rates, divided by total cost. Since class revenues at current rates are much less than total cost, the RCC for the system overall is only 51% and class RCCs range between 43% and 84%. When the RCCs are shown with a base indexed to 100%, the results for the major domestic classes appear very different from those yielded by either the Current Method or Manitoba

Hydro's Recommended Method. In particular, Mr. Lazar's results show that the Residential, General Service Small and Area and Roadway Lighting classes have RCCs greater than 100% while all other classes have RCCs less than 100%.

For reasons which are further elaborated on pages 26 through 30 of this rebuttal, Manitoba Hydro does not believe that Mr. Lazar's suggested approach is appropriate for demonstrating the extent of cost recovery parity among classes. However, his example does illustrate the significance of the marginal cost/embedded cost dichotomy and the extent to which export revenue allocation contributes to it. Manitoba Hydro offers the following modification of Mr. Lazar's analysis in the same spirit and as a possible cross check on the results of other methods being potentially considered for adoption.

Attachment MH-2 modifies this analysis by providing net export revenue credits to the domestic classes, allocated on the basis of marginal supply costs. Conceptually, this is also an instructive approach, since it assigns both costs and credits based on marginal cost and therefore eliminates the distortion of cost allocation caused by allocating marginal cost based credits against embedded cost. Attachment MH-2 also depicts an initial allocation of net export revenues in respect of policy objectives as well as to provide the curtailable credit to the General Service Large class.

The results of this exercise demonstrate that most classes fall within the Zone of Reasonableness. Both Residential and General Service Large >100 kV are almost exactly at unity. General Service Small Non-Demand is slightly outside the zone, as it is with the other approaches to cost allocation. General Service Large <30 kV is significantly outside the zone, a situation that also arises with the other approaches to cost allocation. Area and Roadway Lighting is significantly above the ZOR, an anomaly that arises with any method that indexes the overall system RCC from a low base (such as 72.5% in this case) to 100%, and one which arises because of the relatively small share of Generation costs in the overall class cost of service.

**MH REBUTTAL
ATTACHMENT-1(1)**

**EXPORT REVENUE ALLOCATION - ENTITLEMENT METHODOLOGY
CALCULATE 2005/06 UNUSED ENERGY ENTITLEMENT**

		Class Baseline Energy Use Base Year 1996/97[1] MW.h	Share of Energy 1996/97 Per Cent	2005/06 Energy Entitlement Based on 1996/97 Baseline MW.h	Forecast Energy Use 2005/06[2] MW.h	Unused Entitlement MW.h
Residential		5,866,425	36.7%	11,980,586	7,428,132	4,552,454
General Service Small	**- Non-Demand**	1,385,678	8.7%	2,829,873	1,826,839	1,003,034
	- Demand	1,353,636	8.5%	2,764,435	1,951,645	812,790
General Service Medium		1,928,380	12.1%	3,938,195	3,341,939	596,256
General Service Large	**<30 kV**	1,073,625	6.7%	2,192,589	1,670,799	521,790
	30-100 kV	544,511	3.4%	1,112,016	857,657	254,359
	> 100 kV	3,748,009	23.5%	7,654,295	5,661,263	1,993,032
Area and Roadway Lighting		80,642	0.5%	164,689[2]	112,204	52,485
Diesel						
Total		15,980,906	100.0%	32,636,678[2]	22,850,478	9,786,200

[1] At Generation – see PCOSS 1996/97, page 111.
[2] At Generation – see PCOSS 2005/06, page 85.

MH REBUTTAL ATTACHMENT-1(2)

EXPORT REVENUE ALLOCATION - ENTITLEMENT METHODOLOGY
CALCULATE 2005/06 UNUSED CAPACITY ENTITLEMENT

		Class Baseline Capacity Use Base Year 1996/97[1] MW CP	Share of Capacity 1996/97 Percent	2005/06 Capacity Entitlement Based on 1996/97 Baseline MW	Forecast Capacity Use 2005/06[3] MW CP	Unused Entitlement MW CP
Residential		1,395.6	45.9%	2,222.9	1,263.3	959.6
General Service Small	**- Non-Demand**	307.8	10.1%	490.3	308.3	182.0
	- Demand	284.1	9.3%	452.5	298.9	153.6
General Service Medium		388.6	12.8%	619.0	512.0	107.0
General Service Large	**<30 kV**	180.8	5.9%	288.0	242.6	45.4
	30-100 kV	77.9	2.6%	124.1	99.3	24.8
	> 100 kV	384.1	12.6%	611.8	642.5	(30.7)
Area and Roadway Lighting		19.8	0.7%	31.5	8.7	22.8
Diesel						
Total		3,038.7	100.0%	4,840.0[2]	3,375.6	1,464.4

[1] At Generation – see PCOSS 1996/97, page 113.
[2] System peak load – January 18, 2006.
[3] Current Filing – Appendix 11.3, page 92.

MH REBUTTAL ATTACHMENT-1(3)

EXPORT REVENUE ALLOCATION - ENTITLEMENT METHODOLOGY
DETERMINE NET EXPORT REVENUE ENTITLEMENT

		Export Revenue Initial Policy Related Allocation $000	Allocation Based on Unused Energy Entitlement $000	Allocation Based on Unused Capacity Entitlement $000	Total Export Revenue Allocation $000
Residential		16,700.0	123,432	91,176	231,308
General Service Small	**- Non-Demand**		27,196	17,289	44,484
	- Demand		22,037	14,595	36,633
General Service Medium			16,166	10,162	26,329
General Service Large	**<30 kV**		14,147	4,311	18,459
	30-100 kV		6,897	2,354	9,251
	> 100 kV		54,038	(2,918)	51,120
Area and Roadway Lighting			1,423	2,170	3,593
Diesel		2,405.0			2,405
Total		19,105.0	265,336[1]	139,140[1]	423,581

[1] Classification based on System Load Factor of 65.6%.

**MH REBUTTAL
ATTACHMENT-1(4)**

**EXPORT REVENUE ALLOCATION - ENTITLEMENT METHODOLOGY
DETERMINE CLASS REVENUE COST COVERAGES**

		Allocated Cost Current Method $000	Class Revenue $000	Net Export Revenue $000	Total Revenue $000	Revenue Cost Coverage Ratio
Residential		605,679	413,604	231,308	644,912	106.5%
General Service Small	**- Non-Demand**	138,476	107,252	44,484	151,736	109.6%
	- Demand	120,301	90,862	36,633	127,495	106.0%
General Service Medium		196,833	139,754	26,329	166,083	84.4%
General Service Large	**<30 kV**	95,617	59,106	18,459	77,565	81.1%
	30-100 kV	38,100	26,974	9,251	36,225	95.1%
	> 100 kV	222,694	158,829	51,120	209,949	94.3%
Area and Roadway Lighting		19,988	19,297	3,593	22,890	114.5%
Diesel		10,840	9,309	2,405	11,714	108.1%
Total		1,448,528	1,024,987	423,581	1,448,568	100.0%

MH REBUTTAL
ATTACHMENT MH-2

SUBSTITUTING MARGINAL GENERATION COSTS WITH NET EXPORT REVENUE ALLOCATION IN COST OF SERVICE STUDY

		Class Revenue From Rates	Marginal Supply Cost[1]	Allocated Generation Cost[1]	Difference	Total Cost With Margin Energy Cost	Initial Export Revenue	Remaining Export Revenue	Total Class Revenue	Revenue Cost Coverage	RCC Index to 1.000
Residential		413,604	398,491	176,000	222,491	774,475	16,700	129,547	559,851	0.723	0.996
General Service Small	**- Non-Demand**	107,252	102,245	45,158	57,087	182,376		33,239	140,491	0.770	1.062
	- Demand	90,862	108,498	47,920	60,578	169,242		35,272	126,134	0.745	1.027
General Service Medium		139,754	183,598	81,089	102,509	280,072		59,687	199,441	0.712	0.982
General Service Large	**<30 kV**	59,106	93,403	41,253	52,150	138,461		30,365	89,471	0.646	0.891
	30-100 kV	26,974	43,705	19,303	24,402	58,378		14,208	41,182	0.705	0.972
	> 100 kV	158,829	282,788	124,898	157,890	354,651	8,200	91,933	258,962	0.730	1.007
Area and Roadway Lighting		19,297	6,226	2,750	3,476	22,926		2,024	21,321	0.930	1.282
Diesel							2,405	-			
Total		1,015,678	1,218,954	538,371		1,980,581		396,276[2]	1,436,854	0.725	1.000

[1] As per TREE Exhibit JL-4
[2] Sum of initial and remaining export revenues is $423,581,000, the same amount as is allocated in PCOSS06 using the Current Method.

<u>Concept of "Threshold" Export Revenues to Define Limit of Offset Against Generation and Transmission Costs</u>

MIPUG witnesses' evidence has introduced the concept of a "threshold" of net export revenues, beyond which "the standard approaches to providing this benefit directly via bulk power rates are no longer appropriate" (page13, lines 21-22). The witnesses go on to conclude that "Hydro's filed material implicitly assumes the existence of an export revenue threshold beyond which existing cost-of-service methods are no longer appropriate, but makes no explicit attempt to define that threshold" (page 14, lines 13-15). Do you agree with the MIPUG evidence in this regard?

Manitoba Hydro does not support the adoption of a "threshold" concept of net export revenues which would be credited to domestic customer classes based on the use each of those classes make of the Generation and Transmission functions only. Further, if such a concept were to be considered, it is not appropriate to define such a "threshold" in terms of export revenue percentage of total revenue, related to what may or may not have been considered reasonable in the past. This is what MIPUG has attempted to develop in its evidence on pages 15 and 16. In this evidence the witnesses attempt to adduce a "threshold" in terms of export revenue as a percentage of total revenue by looking at the evolution of this ratio over time. They suggest that the ratio of 32.7% is below such a "threshold" because that was the ratio in the 1996/97 PCOSS at which time the treatment of export revenues was deemed to be "patently reasonable" (page 16, lines 8-11). If such a ratio is "unreasonable" in 2005/06 when the ratio is estimated at 42.7% then, the witnesses reason, the "threshold" must fall somewhere between these two percentages, and they then proceed obligingly to estimate the "threshold" as the mid-point of these two percentages. They reach the conclusion that only $49.5 million of the net export revenues is beyond the "threshold" and the remaining $374 million can be safely (and fairly) allocated on the basis of class usage of the Generation and Transmission functions.

The principal problem with the approach proffered by MIPUG's witnesses to define and calibrate this "threshold" is that it is not related in any meaningful way to the problem of distortion of cost responsibility induced by export revenue allocation. This occurs when sales that were formerly "by-products" exported at low prices, and whose revenues could meaningfully be applied to pricing the domestic product, have become premium products relative to the domestic product, at least in terms of the value received.

MIPUG's witnesses cite 1996/97 as being a year in which the treatment of export revenues was "patently reasonable" and goes on to conclude that therefore, a "threshold" of 32.7% is patently reasonable. In 1996/97, the embedded cost of Generation and Transmission, as it appeared to domestic customers was 2.84 cents per kW.h. The average export price received, as reported in Manitoba Hydro's Annual Report, was 2.3 cents per kW.h. Although not noted at the PUB proceeding at which this cost of service was reviewed, it was already becoming apparent that net export revenue allocation was affecting class RCC's more than the domestic rate increase differentials available to Manitoba Hydro at that time.

The 2005/06 Cost of Service Study demonstrates a significant further increase in the amount of export revenues. Average price expected to be received for exports in the study is estimated at 5.59 cents per kW.h. By contrast, the embedded Generation and Transmission costs that are left for recovery from domestic customers, were the current export allocation method to be maintained, would actually be less than in 1996/97, at 2.49 cents per kW.h.

It may be that such a "threshold" concept could be usefully examined in order to provide a cross-check against alternate cost of service concepts. In this case, a more realistic approach would be to examine the impact of diversion of export revenue on customer rates. It has been noted by Manitoba Hydro and others in recent proceedings that the longstanding method of export revenue allocation may have been appropriate when diversion of a kW.h from the export market to the domestic market actually increased Manitoba Hydro's overall revenue, thereby benefiting all customers. Continuing to return export revenues to customers in proportion to their use of the resource when such use actually reduces Manitoba Hydro's revenue and creates a requirement for rate increases for all classes is inefficient. MIPUG's criterion of "what was considered reasonable in the past" and particularly its arbitrary 37.7% would retain this inefficiency. This is because this definition of "threshold" does not recognize the impact of the credit on long-term rates to all customers

Attachment MH-3 below depicts the 2005/06 Cost of Service Study results utilizing the Current Method (i.e. export revenue credit based on Generation and Transmission usage) but limits the "threshold" to a portion of export revenues equal to the ratio between the embedded Generation and Transmission costs being recovered from domestic rates (e.g. 2.49 cents per kW.h) and the revenue per kW.h being recovered from export sales, both firm and opportunity (5.59 cents per kW.h). Unlike the MIPUG witnesses' proposal, this ratio, actually addresses the distortion issue, since any increased use by a domestic customer only increases the export credit to its class by 2.49 cents per kW.h. This amount is equal to embedded Generation and Transmission costs and is not greater than the new domestic revenue provided by that customer. On this basis, the percent of export revenues that could be returned to customers in PCOSS06 is a much lower 44.5%. The remaining 55.5% would be beyond the "threshold" and would not be explicitly factored into the determination of class Revenue Cost Coverage ratios.

In this analysis, the sum of class revenue from domestic rates plus export revenue credit when summed over all classes is insufficient to meet the revenue requirement. This is shown in the second last column of Attachment MH-3, where the overall RCC for all classes combined is only 83.8%. If a "policy" decision were to be made to use the net export revenue not explicitly factored into the cost analysis for other purposes (e.g. DSM, rate stabilization fund), then it would not be available to maintain lower current rates and rate increases would be required to replace the shortfall relative costs. In the example below, it is assumed that this export revenue continues to be available to support current costs; therefore, the relevant RCC ratios are calculated by indexing the RCC to 100%, which is equivalent to adjusting all class revenues plus allocated share of the export credit "threshold" by a factor of 1.193.

The last column shows the resultant RCC ratios for all domestic classes. It can be noted that, with only one exception, these ratios are very similar to those derived using Manitoba Hydro's Recommended Method.

MH REBUTTAL
ATTACHMENT MH-3

CLASS REVENUE COST COVERAGE
CURRENT METHOD WITH CAP ON NET EXPORT REVENUE FOR ALLOCATION

		Total Cost Current Method	Class Revenue	RCC % Pre-Export Allocation	Initial Export Revenue	Class Share G & T Cost Current	Share of Net Export Revenue[1]	Class Rev Plus Exports	Revenue Cost Coverage	RCC Index to 1.000
Residential		605,679	413,604	68.3%	16,700	34.19%	74,614	488,218	0.806	0.962
General Service Small	**- Non-Demand**	138,476	107,252	77.5%		8.62%	14,601	121,853	0.880	1.050
	- Demand	120,301	90,862	75.5%		8.88%	15,042	105,904	0.880	1.051
General Service Medium		196,833	139,754	71.0%		15.02%	25,442	165,196	0.839	1.002
General Service Large	**<30 kV**	95,617	59,106	61.8%		7.52%	12,738	71,844	0.751	0.897
	30-100 kV	38,100	26,974	70.8%		3.42%	5,793	32,767	0.860	1.027
	> 100 kV	222,694	158,829	71.3%		21.94%	37,164	195,993	0.880	1.051
Area and Roadway Lighting		19,988	19,297	96.5%		0.41%	694	19,991	1.000	1.194
Diesel		10,840	9,309	85.9%	2,405		2,405	11,714		
Total		1,448,528	1,024,987	70.8%	19,105	100.00%	188,494	1,213,481	0.838	1.000

[1] Maximum per cent of Net Export Revenue available for allocation is set equal to the ratio average embedded cost of Generation and Transmission $.0249) and the average export revenue per kW.h ($.0559) multiplied by net export revenue of $423,581

i.e. 44.5% x $423,581,000 = $ 188,493,545

__Insufficiency of Inverted Rates to Deal Fully With Efficiency or Equity Issues__

MIPUG's witnesses evidence is that adoption of inverted rates is all that is required to assure efficient pricing, and, by implication, that it is not necessary to make changes in the methods by which export revenues are allocated to domestic customers to reflect considerations of fairness or economic efficiency. Do you agree?

MIPUG's witnesses have stated: "To secure efficient pricing for any given customer of any type (from residential to large industrial) in the context of regulated cost-based rates, it is only necessary to design their rates so that the ***marginal*** consumption (and not all consumption) is priced at marginal cost…This type of rate design can be implemented with Manitoba Hydro's existing cost-of-service approach without requiring the complicated changes proposed by Manitoba Hydro and NERA" (page 19, line 27 to page 20, line 6).

Manitoba Hydro agrees that rate design, such as inverted rates, is useful in providing correct price signals to a wide range of electricity customers. However, the MIPUG witness' assertion that rate design is sufficient to achieve this objective in all cases, regardless of the overall quantum of cost to be recovered is deeply flawed. Inverted rates cannot always be designed to assure the application of marginal price to marginal consumption. The insufficiency of inverted rates to achieve this state becomes obvious if one were to suggest that a rate structure is fair and efficient even if 90% of usage is provided at zero cost to the customer, provided the last ten per cent of usage is priced at marginal cost. But the example doesn't have to be that extreme for the MIPUG witness' reasoning to fail.

In some situations, inverted rates may provide only a very weak connection between marginal usage and marginal cost. Well designed inverted rates should expose as many customers as possible to the marginal cost for at least some of their usage. However, inverted rates designed to be revenue neutral, must balance two factors, both of which can act to reduce exposure to the marginal cost based part of the rate structure. Consider a simple inverted rate for Residential customers. If the level of usage at which the marginal rate is set at 1,000 kW.h per month, any customer using less than that amount will not be affected by the marginal rate. More than 60% of Residential bills in Manitoba, in fact, are for less than

1,000 kW.h per month. Lowering the level of consumption at which the marginal cost is charged exposes more customers to the marginal cost. However, in a revenue-neutral world, it also reduces the revenue requirement and the rate from the inframarginal charge. Therefore, for those fewer customers whose usage does not pass the "threshold", the deviation of price below marginal cost is even greater.

Mr. Harper's evidence recognizes this limitation. On page 56 he states: "…such approaches have their limitations and will be restricted in terms of their effectiveness by the overall revenue requirement to be recovered from the class. For example, if marginal costs are significantly higher than average costs then an inverted rate design is limited in terms of how much consumption it can be applied to (i.e. where the cutoff point for the last block of energy usage can be set) without significantly distorting the pricing structure for the earlier usage block(s) which are also likely to apply to some customers' incremental consumption.

This conclusion can be demonstrated with a simple example. The percentage distribution of bills and of kW.h by Residential customers in Manitoba is depicted below.

	% of bills	% of kW.h
< 250 kW.h	12.7	1.3
250-500 kW.h	17.5	5.4
500-1,000 kW.h	31.1	18.3
1,000-2,000 kW.h	22.0	24.8
2,000-5,000 kW.h	14.0	34.6
> 5,000 kW.h	2.7	15.6

Suppose the total usage by Residential customers is 1,000,000 kW.h. Assume that the average cost is 4.0 cents per kW.h and the marginal cost is 7.0 cents per kW.h. The revenue requirement of $40,000 could be recovered with a single flat energy charge of 4.0 cents per kW.h. Alternatively, it could be recovered with a two block rate with marginal cost applying to the last block and the first block price being set to recover the remainder of the revenue requirement.

Set the size of the first block to 1,000 kW.h and the rate for usage above the first block at 7.0 cents. This marginal rate will apply to (24.8 + 34.6 + 15.6) = 75.0% of the usage, but will affect only (22.0 + 14.0 + 2.7) = 38.7% of the customer bills. The rate will recover (75% x 1,000,000 x $.07) = $52,500, which exceeds the revenue requirement. To be revenue neutral, the rate paid by 61.3% of the customers and affecting 25% of the usage, would have to be negative. It would be, in fact, -$12,500 / (.25 x 1,000,000) = -$.05 per kW.h. Most observers would agree that this is "significantly distorting the pricing structure for the earlier usage block(s) which are also likely to apply to some customers' incremental consumption", to use Mr. Harper's words.

It is also useful to determine what the size of the first block would be so that its price would at least not be negative. The number of kW.h priced at 7.0 cents, that would recover the Revenue Requirement of $40,000 is approximately 571,000 or 57% of the total usage assumed in this example. By rough interpolation using the table above, that block size is approximately 1,700. This means, again using rough interpolation that only about 23% of the customers would face the marginal rate. Indeed, in this example, only 23% of the customers would face a non-zero rate.

Clearly then, there are limitations to the extent to which an inverted rate structure can compensate for a low revenue requirement in the face of a substantially higher marginal cost. Manitoba Hydro expects it can design a meaningful inverted rate for residential customers, because it expects to deal with an overall revenue requirement (embedded cost) in the order of six cents per kW.h and a marginal cost in the order of 7.0 cents per kW.h. However, the gap between marginal and embedded costs is significantly greater for large industrial loads, particularly if the COSS were to retain the Current Method of allocating net export revenue.

Adopting a rate structure such as the BC Hydro "stepped rates" referenced in the MIPUG witnesses' evidence on pages 38 through 41, without taking any other measures, would mean that only a very small percentage, if any, of existing load or, more significantly, load growth, would be exposed to marginal cost. Manitoba Hydro has addressed this concern in its responses to Information Requests. For example, in the response to MIPUG/MH I-15(a), Manitoba Hydro has noted: "The difficulty in applying marginal rates to all new load is greatest for large industrial customers. A stepped rate design, such as that now being implemented by BC Hydro, does not change the overall embedded cost basis of the rate design. It captures marginal cost from only the last 10% of each customer's load, and the rate applying to the inframarginal load is actually reduced, such that the overall revenue is neutral for an existing customer who does not change load quantity or pattern. For a new load or an expansion, the aggregate rate is based on embedded cost; in effect, the entire load fails to capture marginal cost. This type of rate design produces good incentives at the margin to encourage DSM or cogeneration for the last 10% of each customer's load, but it has no impact at all on location or expansion decisions which continue to be driven by the low, embedded cost based rate."

Hence important customer decisions regarding usage, such as those to move new load into Manitoba or to undertake a major expansion, do not face marginal cost in any meaningful way. Yet these are the decisions that are largely responsible for the significant increases in industrial load that have occurred in the past five years. Further, other aspects of the MIPUG witness' evidence are not encouraging with regard to the real ability to charge marginal cost to marginal loads. On page 40, lines 21-22, they state: "The rate should clearly ensure it is not a barrier to growth or development of new loads in the jurisdiction…" In response to MH/MIPUG-8, the witnesses agree that a stepped rate similar to BC Hydro's proposal effectively exposes new or expansion loads to no price signal in excess of embedded cost, which is the same effect as maintaining an existing (non-inverted) rate.

It is also important to note that the use of inverted pricing can never compensate at all for an unfair or unreasonable allocation of revenue requirement. Maintaining the Current Method of allocating net export revenues on the basis of Generation and Transmission only is not in keeping with cost causation principles in a situation where the unit revenues so significantly exceed the embedded costs upon which rates are based. MIPUG's position, that ratepayers are entitled to all, or most, net export revenues, allocated on the basis of their current use of the Generation and Transmission functions, essentially amounts to stating that any increase in the economic value of these resources should be credited on the basis of current use. This is clearly neither sound economics nor sound public policy and, therefore, not a sound basis for cost allocation.

Treatment of CO_2 Emissions in Cost of Service Study

Mr. Lazar's evidence is that certain environmental external costs that are the result of the production of energy by other generators outside of Manitoba should be considered in Manitoba Hydro's cost of service analysis and possibly within Manitoba Hydro's Revenue Requirement. Do you agree?

No. The notion that Manitoba consumers should pay more for their electricity, because other jurisdictions use more fossil-fuel is not justified. Manitoba Hydro does not support Mr. Lazar's recommendations with respect to building in additional CO_2 considerations in the COSS or other rate setting exercises.

Manitoba Hydro expects that the greenhouse gas externality will be increasingly internalized by future Canadian and U.S. energy and environmental policies. This is expected to occur over an extended timeframe; a timeframe comparable with Mr. Lazar's recommendation to "plan gradual movement toward full-costing" (page 19, lines 31-41). The implications of these future policies are already built into the export price forecast that is utilized by Manitoba Hydro to evaluate new resources including new supply as well as Power Smart programs.

Manitoba Hydro also notes that significant environmental externalities, related to production of electricity within Manitoba, are already internalized within Manitoba Hydro's cost structure and reflected in the rates paid by domestic consumers. For example, the response to PUB/MH I-8 documents the extensive mitigation and compensation costs incurred in respect of northern hydraulic generation facilities.

Does Manitoba's *Sustainable Development Act* (SDA) require Manitoba Hydro to add environmental or other externalities into its costs for the purpose of cost of service analysis or rate setting?

No. *The Sustainable Development Act's* (SDA) Guideline 1, Part (b) recommends "employing full-cost accounting to provide better information for decision makers." Part 1 of *The Sustainable Development Act* defines full cost accounting as follows:

> …accounting for the economic, environmental, land use, human health, social and heritage costs and benefits of a particular **decision or action** to ensure no costs associated with the **decision or action**, including externalized costs, are left unaccounted for; **(emphasis added)**

Manitoba Hydro appropriately considers full cost accounting in its planning and its major decisions and actions to the extent practical. In choosing among options for new generation and in developing conservation programs, Manitoba Hydro considers a range of impacts, including environmental and social impacts of alternative decisions. In seeking to embed CO_2 costs in Manitoba Hydro's electricity rates RCM/TREE appears to have expanded the definition of full cost accounting to include the concept of "full cost pricing". These terms are not synonymous. Full cost pricing goes beyond the consideration of the implications in making significant decisions to quantify the implications as costs and imbedding these in the final price of products. Full cost pricing is not specified by the SDA.

Is there any precedent at all for full cost pricing in the manner recommended in the evidence of Mr. Lazar?

Manitoba Hydro is not aware of any such precedent. Mr. Lazar himself has noted, in his response to PUB/RCM/TREE-3(b): "I am aware of many regulatory commissions that require consideration of environmental costs in resource planning decisions, several that require consideration of environmental costs in resource acquisition decisions, but none that currently incorporate environmental costs into the interclass cost allocation study." As noted above, the directives actually issued by these commissions are consistent with Manitoba Hydro's existing practices related to greenhouse gas and full cost accounting.

Likewise, in his response to MH/RCM/TREE-2(b), Mr. Lazar indicates that he knows of no precedent where environmental costs are incorporated into a utility's cost of service analysis.

In his response to CAC/MSOS/RCM/TREE-2(b), Mr. Lazar identifies Denmark as a country that collects a CO_2 tax per kW.h of electricity used. Manitoba Hydro's understanding is that Denmark does not levy that tax in respect of all energy and the tax is not a precedent for what Mr. Lazar is recommending. It has **not** been put in place to recognize that energy exported, would increase Generation in some other jurisdiction, using technology that releases CO_2.

In those instances where environmental tax or pricing to include environmental impacts are employed, they are more typically used to address the externalities associated within the production of the product. In the case of Denmark, the Danish EPA describes a carbon tax is applied to "energy products depending on their contribution to CO_2 emissions" (www.mst.dk/udgiv/Publications/2005/87-7614-890-4/html/bred29_eng.htm , TD-5-6) The CO_2 tax appears to be based on the emissions associated with the production of the electricity that is used by the Danish consumers. Denmark also applies an energy tax for space heating and hot water. However, energy supplies from bio-fuels and renewable energy appear to be exempt from both of these taxes (www.ens.dk/graphics/publikationer/energibesparelser_uk/EnergyEfficiency/Green_taxes.pdf, pages 6-7). While Mr. Lazar cites Denmark's carbon tax as an example supporting his argument (e.g. PUB/RCM/TREE-3), it actually illustrates that Manitobans being served predominantly by renewable resources should be sheltered from these additional costs. Ultimately the cost of CO_2 emission should be borne by those responsible for the emissions.

<u>**Use of Marginal Generation Costs in Cost of Service Study**</u>

Mr. Lazar, on behalf of RCM/TREE has proposed incorporating marginal generation costs directly in the Cost of Service Study in order to determine class cost responsibility. Does Manitoba Hydro agree with this approach?

Manitoba Hydro sees merit in considering the marginal cost of supply in evaluating an appropriate cost of service methodology. However, at this point, Manitoba Hydro believes it would be premature to utilize Mr. Lazar's suggestion without modification to depict overall class responsibility for costs in the Cost of Service Study.

Mr. Lazar's evidence substitutes marginal generation cost for embedded generation cost in Manitoba Hydro's recommended methodology. On pages 13 and 14 of his evidence, he explains the steps he took to illustrate the impact of his approach. He provides the detailed calculations in his Exhibit JL-4. Mr. Lazar concludes that the domestic classes as a whole are only paying about half the cost of service, including marginal generation costs, and some are as low as 43% (page 13, lines 18-19).

Mr. Lazar is not recommending that rates be increased to close the gap between class revenues and costs as depicted in his evidence, at least not immediately. He notes that a decision to implement this would be a policy decision for the PUB and the Government of Manitoba. He also notes that, increases in revenues resulting from basing rates on marginal supply costs plus embedded costs of all other electric utility functions would provide an additional $700 million per year (page 14, line 18). He recommends that this additional revenue be used to invest in energy efficiency measures, or for general government purposes (page 14, lines 23-28). He concludes this section of his evidence stating: "From *an economic efficiency* perspective, a key goal would be to get prices equal to marginal costs to promote efficient consumption of energy. The use of the funds would be a policy-directed decision." (page 14, lines 28-31)

Elsewhere in his evidence Mr. Lazar clarifies his perspective on increasing revenue requirement to close the gap his analysis identifies. He acknowledges that a major immediate increase to electricity prices would be disruptive to most households and businesses. "A pragmatic approach would be to plan gradual movement toward full-costing, with application of the revenues to fund energy efficiency programs and other societal benefits funded by MH." (page 19, lines 39-41)

This leaves the question as to the extent Mr. Lazar is recommending his analysis be used to determine cost of service results. His recommendation on this matter is expressed on page 16 of his evidence. In this section, he reviews the results of incorporating not only marginal supply costs into the cost of service methodology, but adding in his determination of "environmental externalities" as well. He notes that the cost of service results on this basis, indexed to 100% reflect incorporation of the marginal supply and environmental externalities on a relative basis among the customer classes, without increasing the revenue requirement. His position on this matter appears clear: "Basically, if the rates are only going to recover the embedded revenue requirement, but they are to reflect marginal costs and environmental costs, the Indexed RCC% in this final study should be used by the MPUB to define "parity"." (page 16, lines 6-9) In other words, the following RCC ratios (shown on the top of page 15 in Mr. Lazar's evidence) should be used to guide class revenue adjustments:

Residential	106%
General Service Small Non-Demand	116%
General Service Small Demand	104%
General Service Medium	97%
General Service Large <30 kV	83%
General Service Large >30 kV	87%
General Service Large >100 kV	84%

Manitoba Hydro discusses on pages 23-25 in this rebuttal evidence why it is not appropriate to consider Mr. Lazar's depiction of environmental externalities in this analysis. However, even excluding Mr. Lazar's environmental externalities, the results of adopting Mr. Lazar's position with respect to marginal supply costs yields very similar results (page 13, lines 21-22).

Residential	104%
General Service Small Non-Demand	115%
General Service Small Demand	105%
General Service Medium	97%
General Service Large <30 kV	83%
General Service Large >30 kV	90%
General Service Large >100 kV	87%

Manitoba Hydro has discussed extensively the potential use of full estimated marginal cost as a measure of interclass equity in cost recovery, in its responses to PUB/MH I-1. In the response to part (b) of that question, Manitoba Hydro explained its rationale for presenting an embedded instead of a marginal cost study. Manitoba Hydro also noted that a few utilities do use marginal cost as a benchmark for fairness of revenue allocation. That response also indicated that these utilities incorporate marginal cost for all components of service, not just energy supply.

In part (d) of that response, Manitoba Hydro has provided class revenue cost coverage ratios based on marginal costs of supply and marginal cost of expansion of the Transmission and Distribution systems, a more complete measure of marginal cost than that employed by Mr. Lazar. Indexed to 100% these results would be as follows:

Residential	116%
General Service Small Non-Demand	126%
General Service Small Demand	91%
General Service Medium	90%
General Service Large <30 kV	80%
General Service Large >30 kV	84%
General Service Large >100 kV	84%

These results are, in a relative sense, similar to those obtained by Mr. Lazar, even though they substitute marginal for embedded cost for a larger share of Manitoba Hydro's costs. However, they still fail to capture all marginal costs applicable to Manitoba domestic customer classes. In particular, Manitoba Hydro's marginal operating costs for Transmission and Distribution and Manitoba Hydro's marginal customer costs have not been incorporated. Adding these costs to the mix would affect mostly Residential and General Service Small customer classes and would have very little impact on classes served from the Transmission or Subtransmission systems. Therefore, like Mr. Lazar's estimates, the above estimates overestimate revenue to marginal cost ratios for Residential and General Service Small and underestimate the ratios for General Service Large. Hence, while they may still provide useful checks against other measures, Manitoba Hydro does not share Mr. Lazar's belief that they are fully appropriate to define "parity".

Mr. Lazar himself notes, in his response to MH/RCM/TREE-7 that he is not aware of any jurisdictions which incorporate marginal cost into a regulated utility's cost of service study in the manner depicted in his evidence. He further notes that: "It is common practice to include all marginal costs in a marginal cost study and all embedded costs in an embedded cost study".

In part (d) of this question, Mr. Lazar was asked if he recommended incorporating the marginal cost of the other functions in this type of analysis. His response does not actually make any recommendation with respect to these other functions. Instead, he notes that it is his experience that the gap between marginal and average cost is typically greatest in the case of generation and suggests that a useful first step would be to address generation costs. Manitoba Hydro has no basis to dispute his assertion regarding the gap being greatest for generation. However, to the extent that a gap also exists for other functions (e.g. Distribution and Customer Service), the use of these functions is heavily skewed toward Residential and General Service Small. Therefore, it would seem reasonable that a marginal cost benchmark, to be fair to all classes, would need to incorporate marginal costs for all functions, not only Generation.

Consequently, while Manitoba Hydro concurs that more marginal cost information would provide a useful addition, or cross-check on results obtained by its Recommended Method, its use as a measure of "parity" should be contingent, at a minimum, on the ability to include the full range of marginal cost in the study.

Manitoba Hydro notes that, in another part of this rebuttal evidence (see page 6), it has utilized Mr. Lazar's approach to inclusion of marginal generation costs to demonstrate a potential cross-check on the reasonableness of its own Recommended Method. This does not imply acceptance of Mr. Lazar's recommendation. In fact, the key modification entered into Manitoba Hydro's example is that marginal supply costs are offset by net export revenues and the results thereby modified. The example was used to correct for the anomaly of the Current Method of export credit, whereby revenues based on marginal cost are used to offset embedded generation costs.

Mr. Lazar has indicated that both the Current and Recommended Methods of sharing net export revenues among customer classes, and the consequent low rates put "the entire net benefit at risk for Manitoba citizens, because these low electricity rates are likely to attract a few energy-intensive industries. These new industries could consume the surplus power, eliminate the export revenue, and drive up costs for all of the business and citizens of Manitoba, while providing very few jobs and very little tax revenue. Taking steps to prevent this is probably crucial to the economic health of Manitoba." (page 2, line 46 to page 3, line 5)

Does Manitoba Hydro share this concern?

Yes. While Mr. Lazar's concern is based on economic theory and the relationship of Manitoba rates to rates elsewhere in North America, Manitoba Hydro also recognizes that this type of load has grown faster than any other loads in the province over the last decade and longer. Manitoba Hydro has noted in its response to MIPUG/MH I-14(d), that energy intensive industry has increased loads much more rapidly than other types of industry or other domestic classes in recent years and that the apparent gap between rates and marginal costs is greatest for large industrial load.

This factor alone, however, should not require that Manitoba Hydro abandon its recommended cost of service method. There are remedies available to Manitoba Hydro to price efficiently to proposed major load expansions in the province without sacrificing the benefit of low rates to domestic consumers generally. Manitoba Hydro is currently pursuing alternative remedies involving limits on access to embedded cost based rates for major load expansion in the province. It is expected that a Rate Application will be filed with the PUB in due course.

Treatment of Power Purchases, Thermal Generation and Power Trading Costs

While the evidence of Mr. Bill Harper, on behalf of CAC/MSOS is generally supportive of Manitoba Hydro's recommended approaches to classification of Generation and Transmission cost, Mr. Harper has suggested that all purchased import power costs might be more appropriately assigned directly to opportunity export sales and that wind power purchases might be more appropriately assigned directly to both firm and opportunity export sales. Does Manitoba Hydro accept this suggestion?

Manitoba Hydro does not accept this suggestion. Power purchases from any source may support only one type of sale in any given year, but over the long-term these sources support provision of energy to all customers.

Mr. Harper has stated in his evidence that:

> *"…the PCOSS is based on median water conditions and it appears that for the near-term the amount of surplus hydro available under median flow conditions will be more than sufficient to meet domestic and firm export requirements. Therefore, applying the same principles as used in Current Method (i.e. consider the role of purchases in a typical year) would suggest that all purchased power costs should be attributed to the Opportunity Export class."* (pages 32-33)

With respect to wind power purchases, Mr. Harper's evidence is that:

> *"Wind power purchases are also included as purchased power, despite the fact they are purchased from domestic sources. Such purchases do contribute to dependable energy and, to a significantly lesser extent, capacity reserves. As a result, it would be reasonable to track these costs separately and assign them to both Firm and Opportunity Exports."* (page 33)

In the Manitoba Hydro recommended version two Export subclasses have been created, the Firm and Opportunity subclasses. The Firm Export subclass is treated as another domestic customer in that it is allocated its proportionate share of all categories of Generation and Transmission costs. The Opportunity subclass by comparison is only assigned its proportionate share, that is, 46%, of water rental, fuel and power purchase (including wind power) costs. The balance of water rental, fuel and power purchase costs is included in total Generation cost to be allocated to all domestic customers and the Firm Export class. The split between the two Export subclasses was determined by looking at the future five-year split of export sales; the split was calculated as 54% Firm and 46% Opportunity.

Mr. Harper contends that power purchases are made for two reasons: energy security and economic purchases. He notes that the evidence in the PCOSS is that Manitoba Hydro utilizes power purchases primarily for economic reasons rather than for energy security reasons. According to Mr. Harper this would support 100% of power purchase costs being assigned to the Opportunity subclass. Since wind energy is relatively firm, in Mr. Harper's view, this supports some wind costs being assigned to firm exports, but not to domestic load. Mr. Harper notes that the PCOSS is based on median flows and at median flows, power purchases are surplus to domestic needs.

Manitoba Hydro's current Generation resources include all its hydraulic facilities as well as thermal, wind and import capability. At current domestic loads, Manitoba Hydro has surplus resources of both capacity and energy. At median flows, Manitoba Hydro does not require its thermal resources, its wind resources or power purchases to serve domestic load. In fact, at median flows, Manitoba Hydro does not require its entire portfolio of hydraulic resources to serve domestic load.

It does not follow from this condition of surplus resources, however, that the cost of all power purchases, thermal resources and wind generation should be directly assigned to opportunity exports. These resources are put in place or acquired to be available to all loads served by Manitoba Hydro, and under some conditions, all could be required to serve domestic load or firm exports.

Manitoba Hydro prepares its Cost of Service Study on a prospective basis (i.e. for the next following fiscal year) and it assumes median water flows in the preparation of the study. Were it possible to prepare 86 different cost of service studies, each based on one year of the historic flow record, and then to average the results of those studies (as is done with the Integrated Financial Forecast), the impact of drought on the results of the PCOSS would be considerably greater and the requirement for imports or thermal energy to serve domestic loads or firm exports would be more apparent.

During drought years, power purchases are made to serve domestic load and firm exports. Drought years are relatively infrequent; however, when they do occur, power purchases are much greater than during normal years. For example, over the ten-year period 1995/96 through 2004/05, a total of 16,300 GW.h of energy were purchased from outside Manitoba (see Manitoba Hydro's response to PUB/MH I-22(c)). Of these, some 10,000 GW.h were purchased during the drought period 2002-04 and over 7,000 GW.h were purchased during 2003/04 alone. Hence, it is arguable that, over the past ten years, as much as 60% of the purchased power costs were incurred to serve domestic load and firm exports.

Hence, although in a median year, it may appear that power purchases are made entirely for economic reasons to serve opportunity exports, Manitoba Hydro believes it is appropriate to include a substantial portion of their costs for attribution to domestic and firm export loads. Consequently, 46% of power purchase costs are assigned directly to the Opportunity Export class and the remainder is allocated to domestic customers (approximately 41%) and firm exports (approximately 13%). Manitoba Hydro believes it would not be appropriate or reflective of long-term cost responsibility to assign directly all costs of import power purchases to the Opportunity Export class (and wind purchases to exports only) and notes, moreover, that the impact on class RCCs of doing so would not be material in the Cost of Service Study, as shown in the table below.

Customer Class	100% Power Purchases to Opportunity Sales	Recommended Method
Residential	96.6	97.0
General Service Small Non-Demand	107.3	107.4
General Service Small Demand	105.6	105.4
General Service Medium	100.7	100.6
General Service Large <30 kV	90.1	90.1
General Service Large >30 kV	102.2	101.5
General Service Large >100 kV	104.2	103.2
Street Lighting	107.0	107.1

Mr. Harper has suggested that Manitoba Hydro's treatment of Brandon thermal generating costs is inconsistent with the treatment of power purchases. While he has noted no compelling immediate need to resolve this dichotomy, he suggests that if stakeholders require an immediate resolution, that the approach applied to purchases should be adopted. Does Manitoba Hydro agree?

Manitoba Hydro's Recommended Method treatment of Brandon thermal costs is that 50% of them be treated in the same way as power purchases, that is with an initial direct assignment to opportunity export sales with the remaining 50% to be allocated among domestic customer classes and firm exports. For the other half of Brandon thermal costs, the Recommended Method allocates among domestic classes and firm exports only, with no assignment to opportunity exports.

It has been a long-standing practice in the PCOSS to assign 50% of Brandon thermal generation fuel costs directly to export. This practice has been retained in the current PCOSS for both the coal-fired Unit 5 and the two new simple cycle gas turbines. In the Current

Method, 50% of all fuel costs of both types of units are assigned against export revenues. In the Recommended Method, 45% of the 50% is assigned against opportunity export sales and the remainder is functionalized into the Generation pool. The long-standing practice is based on the significant historical role of Brandon Generating Station in providing energy support to domestic sales during droughts and to reliability in the western part of the province during winters.

The original role of the coal-fired Unit 5 at the Brandon Generating Station was to provide energy support to the predominantly hydraulic system during periods of drought and to provide reliability support for western Manitoba load during the Manitoba peak load periods, i.e. during the cold winter months. For both energy and demand, the original intent was to support domestic requirements. The plant was also available to support export sales, but was rarely operated for this purpose prior to the mid 1990s because export prices were low relative to the operating cost of the unit. However, since the mid 1990s, export prices have increased significantly and the operation of Unit 5 to support export sales has increased correspondingly. Support to domestic load and firm export load is still one of the major roles of Unit 5; however, there are now more times when export prices are high enough to justify operating the unit to support export sales.

The construction of the two new Brandon gas turbines was justified, in part, on the basis that they would firm up export sales. Hence, a case could be made that all of the fuel costs could be assigned directly to firm export sales. Of course the plant is also available to support domestic firmness and reliability. Because of the low efficiency of simple cycle gas turbines relative to intermediate and base load generators, and because of the recent price increases in natural gas, it is very rarely economic to use the gas turbines to support opportunity export sales. In fact, with the exception of the drought year 2003/04, the gas turbines have rarely operated, since support to both domestic and export sales is more cost effectively provided by hydraulic surplus, imports, or from coal-fired Generation. Most of the Generation from the Brandon thermal plant continues to be from the coal-fired Unit 5.

Consequently, Manitoba Hydro believes that retaining the 50/50 split for the Brandon Generating Station continues to be appropriate, as this station is more oriented toward assuring reliability than even power purchases. Hence, there is no apparent inconsistency between the treatment of Brandon Generating Station and power purchases.

Mr. Harper himself has noted that: "There does not appear to be a truly compelling case for adopting one approach over the other" and that "…it would be reasonable to adopt the approaches recommended by Manitoba Hydro for each cost item and request that the Company give the issue further consideration" (page 35).

Mr. Harper also questions Manitoba Hydro's treatment of the thermal Selkirk Generating Station in that no direct assignment to exports is made in respect of its cost. Mr. Harper suggests that "this matter should be pursued further with the Company" (page 38). Does Manitoba Hydro believe there should be some direct assignment of Selkirk Generating Station costs to exports?

No. Selkirk Generating Station's longstanding role has been to provide firm energy support to domestic loads during droughts and peak load reliability support. During the 1990s, prior to conversion to natural gas firing, some opportunity sales were made out of this plant, because the opportunity export market could support the cost of the thermal coal fuel. Since conversion to natural gas firing, there are few times, if any, that the station could be used to support opportunity exports, so its cost is appropriately allocated among domestic classes and export firm service.

Mr. Harper's evidence states that direct costs of export sales (line department activities) should be included in the "cost" of export sales (page 37). What is Manitoba Hydro's position with respect to these costs?

Mr. Harper states: "…Manitoba Hydro has identified a number of internal activities that are associated with its involvement in markets outside the Province. The annual amount involved totals roughly $7.3 million which Manitoba Hydro has not included in the costs to be directly assigned to exports, arguing the amounts are not significant" (page 37).

Mr. Harper believes that a reasonable approach is to assign them 45% to opportunity exports and 55% to firm exports (page 38).

As outlined in Section A of the PCOSS06 at page 29 there are several line areas of activity within the Corporation that support export sales. This includes not only traders, but also staff involved in negotiating future sales as well as other technical personal that primarily support the export function. Manitoba Hydro explained in the PCOSS that definitively assigning these costs to exports would not be completely accurate as staff can be involved in activities not exclusively related to exports. This includes supporting the importation of power which may or may not be for support of domestic load. In fact, during a year such as 2003/04, most of the activity in these areas was aimed at assuring supply to firm exports and domestic load during the drought.

It is also true that the magnitude of these costs is inconsequential with respect to the results of the Cost of Service Study. However, it would be appropriate to review their current treatment with a view to increasing the share of these costs directly assigned to firm and opportunity exports.

Classification and Allocation of Bulk Power Costs

The evidence on behalf of MIPUG and, to a much lesser extent on behalf of CAC/MSOS, takes issue with some aspects in Manitoba Hydro's recommended cost of service methodology having to do with the classification and allocation of Generation and Transmission function costs. Are the suggestions of the MIPUG witnesses' appropriate modifications to Manitoba Hydro's recommended cost of service methods?

No. In particular, the positions in the MIPUG evidence with which Manitoba Hydro takes most exception are:

– That the cost of service methodology inadequately recognizes capacity in the classification of Generation.

- That the use of the 2 CP method for Transmission other than interconnections is not justified.

Manitoba Hydro also continues to believe that the use of only four time-of-use energy periods to subclassify the Generation function may be sufficient, but is willing to explore the expansion of the method to include additional time periods in order to address concerns raised by both MIPUG and CAC/MSOS. With respect to the overall treatment of the Transmission function, it may not be necessary to have separate treatment for interconnections but rather, that all Transmission could be treated in a similar way, classified as demand related and allocated on a 2 CP basis. On reflection, the differences in results obtained by subclassifying Transmission do not appear significant enough to merit the additional complexity.

These issues are reviewed in more detail below.

Is it necessary to maintain a capacity/energy classification for the Generation function and, in particular, should the system load factor be employed as a basis for that classification?

Manitoba Hydro's Recommended Method has classified virtually all Generation costs as energy. Previously, Generation has been classified into energy and demand related components on the basis of the system load factor. The position of the MIPUG witnesses is that Manitoba Hydro's Recommended Method ignores capacity as a valid cost driver. Their evidence is:

> "*This value of peak capacity is reflected in part in the values attributed to the Curtailable Service Program or in demand-related DSM programming, and it is only reasonable to maintain a similar coincident peak demand related classification for at least part of the generation system. Based on past practice and precedents from other jurisdictions this ratio can reasonably be set using the system load factor (65.60%) or approximately 34.40% to demand in PCOSS06*." (page 22, line 19 to page 23, line 2)

Mr. Harper, on behalf of CAC/MSOS, also appears to consider that Manitoba Hydro's approach to the classification of the Generation function may give inadequate recognition to capacity. Mr. Harper, however, does not take the position that a separate capacity component is required to address this concern; rather, he believes that a larger number of time-of-use energy periods would address it (page 14). This possibility is further considered below.

Manitoba Hydro's position is that the subclassification of Generation into four time-of-use energy periods adequately reflects the capacity component of supply by recognizing a significantly higher value of energy in the peak period. If one adds up the weights used to subclassify Generation, one arrives at a total of (1.000 + 1.295 + 1.923 + 2.101) = 6.319. The difference between the peak weightings and the off-peak weightings would be (1.923-1.000 + 2.101 – 1.295) = 1.729. This part of the weighting reflects the extent to which the peak load hours are weighted over and above the off-peak hours and may be viewed as the capacity portion. In this case, the capacity portion is (1.729 / 6.319) = 27.4%. This proportion is actually greater than the proportion of Generation cost classified to capacity in the "current" methodology. The Current Method actually classifies only 18.3% of Generation costs as capacity related. This is because the load factor method of classification is used to classify the Generation and Transmission functions combined. Since Transmission, in the Recommended Method, is considered almost entirely demand related, the result is that the capacity portion of the Generation function is less than (one minus the system load factor).

MIPUG has suggested that a capacity component is warranted since Manitoba Hydro uses capacity criteria in evaluating different resource options (page 22, lines 11-13) and also notes that the value of peak capacity is reflected in the values attributable to curtailable service or DSM programming (page 22, lines 19-20). Manitoba Hydro's long-term marginal costs, used in all these evaluations do incorporate a capacity component; today it is less than 20% of the overall marginal cost associated with Generation. Consequently it would appear that the capacity component in the Current Method (18.3% of Generation cost) is entirely reasonable. The 27.4% determined above as the extra weighting for the peak period in the Recommended Method is actually considerably in excess of the Current Method capacity component. It is arguable, however, that a somewhat larger percentage is required to recognize the extent to which the number of peak hours in the recommended classification exceeds the number of capacity hours in the current classification.

One way of examining the extent to which the proposed classification method may or may not incorporate capacity considerations, at least relative to the Current Method, is to compare the allocation of Generation costs on a stand-alone basis, using each of the two methods. Manitoba Hydro has carried out this analysis and the results are summarized below. This compares the percentage allocation of costs assigned to the domestic customer classes using each of the two methods.

	Current Generation Classification and Allocation Class Share %	**Recommended Method Classification and Allocation Class Share %**
Residential	33.3%	32.6%
General Service Small Non-Demand	8.2%	8.2%
General Service Small Demand	8.6%	8.7%
General Service Medium	14.7%	14.9%
General Service Large <30 kV	7.3%	7.4%
General Service Large 30-100 kV	3.6%	3.6%
General Service Large >100 kV	23.7%	24.2%
Area and Roadway Lighting	0.5%	0.4%

As can be seen, the Recommended Method actually results in very little change from the Current Method.

Is it necessary to increase the number of time-of-use energy periods used to classify the Generation function in order to adequately depict the variable range of energy prices, to incorporate capacity considerations and to fairly allocate costs among customer classes?

Manitoba Hydro believes that use of the four periods captures most of the time variability of energy marginal cost values. It is not difficult, however, to expand the number of periods to respond to the concerns raised by the witnesses for both MIPUG and CAC/MSOS. However, the use of additional periods does not significantly change the results of the study. In fact, using the twelve weightings suggested by MIPUG in its evidence on page 25, Manitoba Hydro recalculated the results of the Recommended Method by changing only the Generation allocation factors from the four originally used to the twelve suggested by MIPUG in its evidence. The impact on percentage shares allocated among the domestic customer classes is depicted below.

	Recommended Method Four Period Classification Class Share %	**Recommended Method 12 Period Classification Class Share %**
Residential	32.6%	32.9%
General Service Small Non-Demand	8.2%	8.2%
General Service Small Demand	8.7%	8.6%
General Service Medium	14.9%	14.8%
General Service Large <30 kV	7.4%	7.4%
General Service Large 30-100 kV	3.6%	3.7%
General Service Large >100 kV	24.2%	23.9%
Area and Roadway Lighting	0.4%	0.4%

The table above illustrates that the choice of classification periods is a limited driver of change in the allocation of Generation function costs and, consequently, in PCOSS results.

Is it appropriate to adopt a single CP (winter peak) criterion for the allocation of Transmission other than interconnections ("export lines"), as suggested by the MIPUG witnesses?

MIPUG's witnesses note that "…as Hydro has now determined that export transmission lines should be functionalized separate from domestic transmission, there does not appear to be any remaining rationale for the 2 CP allocation for domestic transmission…Allocation using a 1 CP is consistent with a system that has a distinct winter peak well above the levels that are set in the remainder of the year. Hydro's system outside of exports has this type of load profile" (page 23, lines 4-10).

Manitoba Hydro exports utilize both the domestic Transmission system and the interconnections in order to move energy into the export markets. This is reflected, in the Recommended Method, in the allocation of a share of domestic transmission costs to the firm export customer class, as well to all domestic classes. If the exports used only the interconnection, there would be no basis for allocating a share of the domestic Transmission cost to them. Because exports do share in the use (and cost) of all Transmission, the 2 CP method for allocating the costs of Transmission among domestic customer classes and firm exports continues to be appropriate.

Since domestic customer classes utilize export transmission lines, and export customers utilize the rest of the Transmission system, why has Manitoba Hydro proposed, in its Recommended Method, to define the two types of transmission lines and to use different allocators for each?

In the Recommended Method, as originally recommended in the NERA Generation Classification Study, the costs associated with export related transmission lines are allocated on the basis of annual energy, while the remaining transmission facilities are allocated on the basis of demand using a 2 CP allocator.

The original rationale for using an energy allocator for the export lines is because of their role to deliver surplus energy into export markets. The original NERA Generation Classification Study considered that this may provide a rationale for a separate allocation process. The specific discussion of this proposal is found in that document on page 39.

> *This approach attempts to make a more precise distinction between transmission investment related to serving peak loads and that justified because it reduces energy costs or facilitates energy exports. For purposes of illustrating the method, since a detailed study has not been conducted, tie lines were classified as energy, remaining facilities as demand. Further analysis might be able to quantify the reliability v. energy transfer benefits of tie lines, or they could be classified in the same way that generation costs are treated…*

Subsequent internal review leads to the conclusion that the Transmission system, whether it provides energy or reliability benefits, and whether it serves domestic or export customers, is an integrated system and is more appropriately viewed as a single function. Further, the impact of subfunctionalizing the Transmission system and allocating the two parts on a different basis is minimal; export related Transmission is only 17% of total Transmission, or approximately 3% of the total bulk power system costs to be allocated. Consequently, Manitoba Hydro now believes it would be appropriate to classify the entire Transmission system as demand related and allocate its cost on the basis of the 2 CP allocator.