PUBLIC UTILITIES BOARD
(PUB)

REFERENCE: Page 4, Risk Tolerances of Manitoba Ratepayers

QUESTION:

a) Please elaborate on how Messrs Bowman and McLaren came to the conclusion that in all material respects the evidence of this proceeding confirms MH's thresholds for risk tolerance are appropriate.

b) Please explain why the Board should reject KM's recommendation directed at targeting minimized generation cost as opposed to current MH objective of maximizing net revenues.

c) Why is past practice for reserve setting a relevant basis for rejecting the KM recommendation? Explain what is meant by the phrase "fundamental framework for public power development focused on the long-term".

ANSWER:

(a)

Messrs Bowman and McLaren reviewed the relevant risk reports in a manner consistent with Manitoba's regulatory framework, the purpose of which is to set just and reasonable rates. There were no material conclusions in the risk reports that suggest, on balance, that Manitoba Hydro has misportrayed its degree of risk in its own GRA filings or adopted broad management practices inconsistent with reasonable risk management. The information in the GRA filings also confirm previous understandings of Messrs Bowman and McLaren in respect of various ways in which Hydro manages risk, e.g.;

- Long-term assets are largely matched with long-term debt;

- US$ cash flows are internally hedged with US$ borrowings;

- Resource development opportunities are assessed by comparing the financial scenarios where a plant in-service date is advanced, versus one where the plant is only built as needed for domestic supply;

- Hydro does not commit to long-term dependable contracts where they cannot be backed by dependable energy; where dependable energy is available, long-term firm contracts are the preferred method of marketing this power; and

- Merchant transactions are only pursued on an arbitrage basis.

There are many specific comments in the risk reviews that suggest Hydro's practices could be refined or improved – as noted in the pre-filed testimony, the Board should encourage Hydro to adopt the relevant recommendations, while recognizing that various specific recommendations may not have merit from the perspective of a public power utility with a ratepayer-focused risk tolerance.

In the regulatory forum, the utility must put forward its evidence for testing. As noted in the KM Report a regulator or intervenor in such a proceeding is at a substantial information disadvantage (an "information asymmetry"). "The information asymmetry arises in the context of utility regulation because the operator knows far more about its abilities and effort and about the utility market than does the regulator or the public." (KM Report, page 4). For this reason, the regulator and intervenors cannot, and are specifically not expected to, supplant the role of the utility's management.

One cannot review the risk reports (or other evidence on the record) and conclude with certainty that IFF10 precisely forecasts the upcoming 10 years in all material respects, or that the cost of a 5 year benchmark drought is precisely as set out by Hydro. However, from the review of the hearing record that Messrs Bowman and McLaren were able to perform, there is no readily apparent basis for concluding that Hydro's forecasts of such factors as water flows and export revenues, to the degree required for setting rates today, are unreasonable.

(b)

The explanation for why the Board should reject the KM recommendation on a "minimize generation costs" target as opposed to a "maximize net revenue" target is set out at page 36 of the pre-filed testimony of Messrs Bowman and McLaren.

(c)

Please see CAC/MSOS/MIPUG-I-9 (a) through (c).

REFERENCE: Page 5, Emergency Reserves

QUESTION:

a) Does MIPUG accept the merit of the 'reserves for emergency risk' principle? What is the merit in delaying implementation of a reserve plan, if the principle is accepted?

ANSWER:

(a)

Messrs Bowman and McLaren have advocated the concept of identified reserves, but not necessarily targeted in some manner solely to "emergencies" (however that may be defined). The recommended goal of the reserve recommended by Messrs Bowman and McLaren is to aid in stabilizing the rate regime (such that Hydro's reserves are credited in good water/export/price years and available to be drawn down in bad years without material changes needed to rates), and to distinguish the effect of these water/export/price variations on Hydro's income statement from those arising from O&M spending control issues, for example. A fund instead designed for emergencies (or "drastic drought" as set out in the KM Report) would appear more oriented as a final protection for investors/lenders before some default in extreme scenarios, rather than a useful tool for assisting ratepayers.

If the principle is accepted, the only merit in delaying implementation of a reserve plan is to develop the appropriate mechanisms and operating rules. The only specific proposed reserve mechanics before the Board today is that put forward by Mr. Matwichuk. The Matwichuk concept is helpful as a starting point and has some aspects of merit; however, this specific concept also has elements of mechanics on which Messrs Bowman and McLaren would likely differ from Mr. Matwichuk, for example this includes items such as the following:

- **Definition of Net Export Revenue:** Mr. Matwichuk recommends using the calculation of Net Export Revenue consistent with the calculations in the respective PCOSS, It appears this approach would entail certain difficulties (such as the PCOSS calculations only being performed on forecasts costs in any given year, not actuals) that could be readily resolved by instead adopting values based on the Hydro concept of "Extraprovincial Revenues (net of fuel, purchased power and water rentals)" which is readily calculated for forecasts or actuals (for example, see PUB/MH-I-1 (Revised)). See CAC/MSOS-MIPUG-11.

- **Potential for Negative Values:** Given the format of reserves being considered, it is not clear that the concept should be structured to permit negative net balances (i.e., presumably representing amounts owing from ratepayers for collection in future periods). As noted in Mr. Matwichuk's evidence Table 4, his concept appears to permit such values. More appropriately, in the event there were no remaining reserves during a period of drought, the financial impacts should simply be recorded in Hydro's net income and retained earnings, rather than by creating some notional balance sheet asset in the form of a "negative reserve".

- **Annual Amortization of Reserve Balances:** Given the lengthy periodicity of hydrology, it is not apparent that balances in the reserve should be amortized annually, as recommended by Mr. Matwichuk, whether over a 5 year period or something longer. It is also not apparent how the amortization recommended by Mr. Matwichuk would operate in a non-test year (i.e., how would customers see the benefits/costs of this amortization without changes to rates?). As a simple and practical approach, at a minimum until an appropriate reserve balance has been established, the reserve balance should simply be retained for adverse events rather than being amortized to income in part each and every year.

- **Notional Interest:** Consideration should be given to the reserve "earning" notional interest annually, with this interest being included as a ratepayer cost in calculating appropriate rate levels. This may prove helpful to the stability of rates after a drought (e.g., if there were a $2 billion reserve that was drawn down during the drought, rate levels before the drought would have already been set at a level that includes a notional interest cost on these reserve amounts, so that the necessary new borrowings required to fund cash requirements of Hydro during the drought will not come with "new" interest costs to ratepayers that become an upward rate driver).

It is possible these and other issues that may exist with the reserve concept can be suitably explored and addressed in the present proceeding to permit establishment of the reserve mechanism out of this GRA; in the alternative, it would be reasonable to permit these details to be worked out in an orderly manner prior to the next Hydro GRA (see also MH/MIPUG-2).

In any event, there is no basis today to consider emergency reserve funds for "drastic drought" funded by new rate riders as recommended by the KM Report (page 245). The reserve concepts noted above can be suitably established without special rate "riders", by building the reserve amounts out of export revenues in good years. A further step to be pursued in future is to enhance annual reserve allocations via a reduced "Net Export Revenue" credit allocation in the PCOSS (to customer classes who are presently failing to cover their costs, per Table 5.2 of the Bowman/McLaren evidence (page 61)).

REFERENCE: Page 6, Reserves Structure

QUESTION:

a) Does MIPUG have any recommendations as to the format of a reserve structure?

ANSWER:

(a)

Please see PUB/MIPUG-I-2.

REFERENCE: Page 19, Drought Risk

QUESTION:

a) Please compare and contrast the findings of the handling of drought risk between the independent expert engaged by the Board and that provided by KPMG and ICF.

ANSWER:

(a)

The reports filed in this proceeding by Drs Kubursi and Magee (KM), KPMG and ICF make a number of specific findings that relate in one manner or another to the 'handling' of drought risk. Relevant aspects of overlap and comparison are set out below.

Review of Models

With respect to the computer models used to estimate drought risks, plan system operations to acknowledge this risk, and respond to actual drought events, KM, KPMG and ICF have key findings in common in terms of the SPLASH and HERMES models. Most notably, each expresses some support for the approaches used by Hydro and the resulting analysis, but each recommends improvements through evolution away from the present deterministic approach.

The KM and KPMG reports, note that the HERMES and SPLASH models use a linear programming, deterministic approach. The assumption of 'perfect foresight' as being necessary to this approach is also cited as a concern (KPMG 54). "Drought risk is quantified without using a probabilistic stress test, this should be done regularly."(KM xxxii) Both reports recommend that a stochastic framework should be used, or stochastic modules integrated to account for forecast uncertainty (KM xix, 96, KPMG 54)[1].

KPMG acknowledges that MH is exploring new methods of addressing forecast uncertainty, such as a stochastic tree model to "test alternative decision rules under multiple flow scenarios. In this way, optimal decision-making approaches under

[1] KPMG notes "MH staff are aware that algorithms in the scheduling models take inputs as known events and therefore do not account for forecast uncertainty" (55).

uncertainty can be found" (56). Furthermore, MH sets its models to use particular scenarios for water flows, such as lowest flows on record, in generating forecasts of financial and operating results, which allows for an understanding of the variance of outcomes, and "[h]elps address the fact that HERMES and SPLASH do not allow full "Monte Carlo" or multivariate stochastic analysis" (KPMG 57).

ICF notes that MH has recently developed the PRISM model which is capable of calculating probability distributions with a Monte-Carlo simulation. (ICF 22), which is indicated as a favourable development.

Preparedness

ICF suggests the adoption of a formal Drought Preparedness Plan, which could be tested for efficacy in a drought situation with the quantification of multiple variables (ICF 121). ICF also suggests developing a standard drought-related financial management plan with mitigation options, based on the consideration of such factors as the consequences of depleting retained earnings and hedging (the later using the stochastic platform in the PRISM model). "This will facilitate planning and management of the expectations of stakeholder groups", with the example provided being a rate increase (ICF 22).

The KM report implies a need for proper response procedures: "Comprehensive water modeling is required to map all possibilities and prepare a credible drought response… [c]areful planning requires that extreme events be identified, their probability of occurrence acknowledged and a plan put in place to deal with their occurrences via detailed responsibilities and accountability measures"(KM 11). The report notes that after the drought events of 2003/04 (when retained earnings declined by $436 million (KM 11), MH instituted a Drought Management Plan and has been working on a Drought Preparedness Plan, which is yet to be completed, and is recommended that it be completed (KM 40).

Quantification of Drought Risk

KM concludes that MH has more closely calculated the cost of a 5 year drought than the NYC (KM 222).

ICF found that MH's quantification of risk exposure, with a stress test, is reasonable (ICF 21), and that MH's stress case is acceptable (ICF 22). ICF suggests that once in a drought situation, multiple variables could be quantified (the example given is a Monte-

Carlo simulation of cash flow at risk), for tracking risks, and improving planning and communication about the drought and associated risks within the Corporation and to stakeholders (ICF 22, 121).

REFERENCE: Page 26, KM Analysis and Provincial Debt

QUESTION:

a) Does MIPUG agree that with respect to MH's current plans, debt associated with capital expenditures of $16 billion dollars, combined with MH's risk exposure to 5 year drought losses, can produce a result that may reasonably be expected to materially affect the provincial government's debt exposure/credit position?

ANSWER:

(a)

Messrs Bowman and McLaren agree that the noted factors will affect the "provincial government's debt exposure/credit position" but cannot comment on the extent to which this would be "material" in the sense of adversely affecting the province's ability or costs to borrow. It is noted that the credit rating agencies reference Manitoba's "tax supported" debt as the primary concern in developing their respective credit ratings[1]. In this regard, debt borrowed by Manitoba Hydro for projects that have solid long-term business cases are understood to be of considerably less concern.

It is also noted that all borrowings of Hydro carry a debt guarantee fee paid to the province at 1% of net outstanding debt, which will increase to approximately $200 million/year by the end of the "decade of investment". It is not apparent that any potential added costs incurred by the provincial government from guaranteeing this debt (including any potential adverse effects on the province's credit rating, if any) exceed the compensation from this source.

[1] DBRS Rating Report Appendix 65 to the application. (p. 2).

REFERENCE: Page 32, Normal Regulated Utility Risks

> "In most cases, these risks exist for Manitoba Hydro and effectively every other similar regulated utility, and will inevitably lead to changes in the long-term of rates. Where possible, it may be appropriate to consider methods to stabilize aspects of these risks, but, overall, ratepayers cannot [or in some cases should not] ultimately be protected from ongoing long-term realities."

QUESTION:

a) Please indicate and provide examples of risks that ratepayers "should not" be protected from and explain why.

ANSWER:

(a)

The referenced paragraph notes that hydro utilities are subject to ongoing long-term realities, examples of which are provided on pages 32-33 of Messrs Bowman and McLaren's evidence (including inflation, load forecast variability and any consequent requirement to develop over time higher cost resources to supply the overall level of loads, trends in labour costs and justifiable market-based capital cost escalation). These are common and well understood realities for regulated utilities and their ratepayers, and the positive or negative implications for utility revenues (and ultimately rates) are typically addressed within normal rate adjustments that occur in GRA test years.

Messrs Bowman and McLaren note at page 32 it may be appropriate to consider methods to stabilize aspects of these risks within the regulatory framework. However, some aspects of upward rate pressure cannot be avoided. For example, load growth generally puts upward pressure on rates as higher cost sources of supply are required to serve increased loads. Ratepayers should not be "protected" from this reality, but the regulatory framework should seek to implement a stable and predictable approach to managing the rate transition.

REFERENCE: Page 33, Low Flow Years

QUESTION:

a) Please indicate and illustrate to what extent the impact on Net Extra-Provincial Revenues (NER) related to “low flow years” are offset by compensating items. What impacts are not offset by compensating items.

ANSWER:

(a)

The table below compares Net Extra Provincial Revenues for the actual years 2003/04 through 2006/07[1]. The table indicates that for the low flow year 2003/04 water rentals were lower than the other years in the series. However fuel and purchased power costs were substantially higher.

By contrast, in 2005/06 when extra provincial revenues were higher, water rentals were the highest in the series while fuel and purchased power costs were the lowest of the four year period.

Table 1
Net Extra Provincial Revenues ($M)

	2003/04	2004/05	2005/06	2006/07
Extra Provincial Revenues	351	554	827	592
Water Rentals	71	111	131	112
Fuel and Purchased Power	569	135	125	226
Net Extra-Provincial Revenue	-289	308	571	254

[1] Pg. 100 of Manitoba Hydro 2006/07 Annual Report.

REFERENCE: Page 34, Reasonable Reserves

QUESTION:

a) Please indicate to what extent or how reserves should be established to offset the inherent variability of the NER value.

b) Is the indication that there is a need to establish reasonable reserves to maximize rate stability consistent with the establishment of a specified reserve "RSR" for such purpose.

ANSWER:

(a)

Please see PUB/MIPUG-I-2.

(b)

Generally yes, if properly structured. As set out in PUB/MIPUG-I-2, the concept for reserves set out by Mr. Matwichuk have significant merit, but are suggested by Messrs Bowman and McLaren to be adjusted in a manner that focuses on a long-term horizon rather than the 5 year amortization "smoothing" type of approach Mr. Matwichuk has suggested.

REFERENCE: Page 35, MH Development Plan and Ratepayer Risk Tolerance

QUESTION:

a) What is the source of the reference to the "understood risk tolerance of Manitoba ratepayers"?

b) What specific assumptions are used by MIPUG in concluding that MH's plan will match long-term dependable power and long-term costs (such as interest rates) and revenues (such as locked in contracts)?

ANSWER:

(a)

The discussion of Messrs Bowman and McLaren's understanding of the risk tolerance of Manitoba ratepayers in Section 3.4.3 is broadly stated and based generally on the following sources:

- Precedents from prior regulatory reviews;
- Well understood principles of rate setting (e.g., Bonbright's principles of rate regulation);
- Practice in other similar jurisdictions throughout Canada; and
- Principles reflected in Manitoba Hydro's own rate objectives.

Manitoba ratepayer risk tolerances are considered to be low over the short term, in large part due to the high premium ratepayers place on rate stability and predictability over time. However, low risk tolerance to rate instability is not determinative to the decision to pursue long term opportunities or short term opportunities that are sufficiently analyzed and bounded, where these provide the means for ratepayers to benefit from the risks they are undertaking (e.g., through lower and more stable rates over the long term planning horizon).

(b)

Section 3.6 of Messrs Bowman and McLaren's evidence summarizes the conclusions from the KPMG, ICF and KM reports, where, to the extent the subject was specifically addressed, a strong preference was noted for the direction and logic underlying Hydro's recommended development plan as opposed to a more limited domestically-focused alternative. In particular, the KM report notes ICF has "produced strong arguments in favour of long-term export sales of firm energy and expanding the system through new massive investments. As a matter of fact, ICF has argued that the two are inseparable". It is understood an approach premised on pursuing long-term export sales and large new capital investments requires the utility to also undertake additional long-term debt.

Messrs Bowman and McLaren noted that an approach that matches long-term dependable power with long-term committed costs (such as interest rates) with long-term revenues (such as locked in contracts) would be consistent with Manitoba ratepayers risk tolerances and preference for long-term rate stability.

REFERENCE: Page 40, Form of Financial Reserves

QUESTION:

a) Please elaborate on how applying the philosophies and mathematics in the KM Report could be utilized for defining criteria for reserve levels.

b) Please indicate what criteria consideration should be utilized in the establishment of a targeted reasonable reserve level.

c) Please elaborate on footnote 84 with respect to the reserve level and provide supporting calculations that demonstrate that increased financing costs related to a benchmark $2.6 billion drought can total a “10% upward rate pressure.”

ANSWER:

(a)

The methodologies advocated in the KM Report are premised on developing an understanding of the probability distribution of key underlying system variables influencing the Financial Forecast (e.g., water, export prices, fuel costs, etc.) and then run Monte Carlo simulations on these distributions, with a given set of inputs (e.g., system configuration, known export contract commitments) to determine the spectrum and likelihood of a particular outcome, which the KM Report focuses on net revenues.

Messrs Bowman and McLaren were simply noting that this approach remains focused on the returns to the utility, rather than a ratepayer focused metric such as rate stability. Were one to want to build upon the KM Report approach, a possible alternative use may be to input the level of domestic rates, and run a long-term simulation (e.g., 20 years) to determine what level of reserves is needed at the outset such that the reserves can be maintained (drawn down and/or rebuilt, etc. throughout the scenario) and such that the reserves are sufficient to permit (with a high degree of confidence) the ability to maintain a stable rate regime throughout the period, rather than having any notable likelihood of needing material rate increases at some point in the scenario to respond to system conditions.

Messrs Bowman and McLaren simply note that some approach oriented towards ratepayers in this manner (rather than shareholders or lenders or depositors) may be possible, but have not in any way tried to develop the modeling.

(b)

As noted in the pre-filed testimony, page 4-5, the cost of a benchmark 5 year drought (without compounding conditions such as high import prices) as has been used in recent GRAs appears reasonable to retain as a proxy. A more refined approach would likely require some evolution as noted in part (a) of this response.

(c)

A drought event, whether met by an equal quantity of retained earnings or not, will require Hydro to undertake material new borrowings to fund cash requirements of the utility. These borrowing requirements will exceed the amounts forecast in an IFF based on median water conditions, and as such will be debt over above that which is included in Hydro's long-term forecasts. The debt will cause associated added interest costs that will form a component of Hydro's costs for setting future rate levels.

The values in footnote 84 are not a precise calculation, but simply note that if a five year benchmark drought were to start in 2011, by 2016 Hydro would have an additional approximately $2.6 billion in added borrowings compared to the IFF10 forecasts, which, at an average debt rate of 5% (which is reasonably representative of the IFF forecast costs of borrowing in IFF10, at page 4), the added annual costs would be on the order of $130 million, or approximately 10% of the then forecast domestic rate levels of approximately $1.3 billion (page 33 IFF10).

REFERENCE: Page 41, Water In Storage

QUESTION:

a) Please provide B&M's views on the trade off of a higher "water in storage" strategy on maximized export sales versus minimizing the need for imports and book out transactions in the determination of optimizing net revenue generation.

b) Did B&M do an analysis of the net system benefit or losses associated with higher "water in storage"? If so, please file, if not please explain.

c) Please provide B&M's understanding of targeted rate riders as utilized in building up a Rate Stabilization Reserve for Manitoba Public Insurance in the 1990's and discuss the appropriateness of such a mechanism in this proceeding.

d) Please explain why the priority allocation of net export revenues is a more appropriate source of funding an RSR versus an additional rider on domestic rates.

ANSWER:

(a) and **(b)**

Messrs Bowman and McLaren have not completed their own analysis of quantitative impacts of higher "water in storage" levels. It is not possible for such a calculation to be performed by Messrs Bowman and McLaren for two reasons:

- First, the KM Report is not specific or quantitative in its proposal, but merely directional:

> "There is a minimum level that should remain in storage consistent with dependable energy targets; the level above that minimum should be part of the mitigation strategy and should be adjusted in proportion to deviation of retained earnings from their targeted minimum. The closer retained earnings are to their minimum desirable value, the higher the water that should be left in storage for drought mitigation purposes."

- Second, Messrs Bowman and McLaren do not possess models of the Hydro system to permit any such revision to be modeled.

However, by definition, optimization of a system must reflect priorities for certain variables or philosophies. It is the understanding of Messrs Bowman and McLaren that Hydro's present philosophy is to optimize the system for maximized net long-term financial returns (from serving export loads), which Messrs Bowman and McLaren agree is appropriate.

The suggestion in the KM Report, as understood by Messrs Bowman and McLaren is that the above system optimization approach should be amended such that an added amount of water is kept in storage at times when retained earnings are low (and presumably therefore less water when retained earnings are high). This suggestion is of concern for two reasons:

1) **Lower Average Returns (Net Exports) Over Time:** As compared to the Hydro optimization approach outlined above, which is intended to maximize long-term returns in the form of net export revenues (such that the mean net income of all water flow cases is maximized), any alternative optimization approach would depart from this maximization of net export revenues. Given Hydro's costs must either be recovered from the net returns from its export market activities, or from domestic ratepayers, this approach means that domestic rates will be higher on average over the long-term to pay Hydro's basic costs, due entirely to lower average returns from the export market[1].

2) **Implicit Sliding Risk Tolerance:** The KM Report suggestion in effect indicates Hydro should operate in a more cautious manner when its retained earnings are low, and a less cautious manner when retained earnings are high. Such an approach appears more oriented to benefit financial markets than ratepayers.

In short, if rates are to be somewhat higher over time to reflect risks, it is preferable to use these higher rates to fund stabilization reserves than to compensate for less-than-optimized system operations.

[1] This is separate and apart from the concept of potentially higher average near-term domestic rate levels to build necessary reserves.

(c)

Messrs Bowman and McLaren do not have a detailed understanding of the MPI rate stabilization reserve from the 1990s. It is understood that MPI is a different form of organization, with limited capital investment compared to Hydro, and with industry-standard reinsurance options for major risks.

Messrs Bowman and McLaren are not aware of rate riders per se being added to MPIs to fund the reserve, but at most a generally higher overall level of rates; this is consistent with the suggestion of Bowman and McLaren that generally higher levels may be suitable over time for Hydro's rates, consistent with achieving a 95%-105% revenue:cost ratio in the PCOSS for all classes without any allocation of "above cost net export revenues" (see CAC/MSOS/MIPUG-I-11).

(d)

The present allocation of "above cost net export revenues" is a purely judgmental percentage credit to all of Hydro's costs in the PCOSS, beyond any cost causation rationale. While the approach benefits ratepayers to varying degrees, the benefit is in the form of lower rates today, rather than a priority allocation of these funds to a reserve that benefits ratepayers over the long-term. It is not clear how the logic for this credit can be sustained if in other aspects of the same rate proceeding, the conclusion is reached that Hydro's present domestic rates are insufficient and special new unprecedented rate riders are necessary to build reserves.

REFERENCE: Section 4.1.1, Page 47, Figure 4.1

QUESTION:

a) Please provide a table of the respective data points utilized in the graph.

ANSWER:

(a)

Please see Table 1.

Table 1

OM&A Spending ($ Millions) Actual and Forecast 2002/03 to 2019/20[1]

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
IFF02-1	$283	$303	$304	$307	$313	$319	$326	$332	$340	$347	$353							
IFF07-1						$351	$360	$369	$377	$389	$398	$406	$415	$423	$431	$453		
IFF10-1									$398	$402	$414	$422	$430	$439	$448	$469	$478	$495
Actuals	$272	$293	$308	$322	$332	$335	$360											

[1] Forecasts taken from each of the referenced IFFs, Projected Operating Statements. Forecast OM&A electric expense from IFF02-1 and IFF07-1 includes the OM&A expense for electric subsidiaries. Forecast OM&A expense for IFF10-1 does not include the electric subsidiary OM&A portion. 2002/03-2006/07 actual Electric OM&A data taken from Coalition/MH II-18a from the 2008 GRA. 2007/08 Actual amount as per CAC/MSOS/MH II-20b from 2010/12 GRA. Actual OM&A expense from 2002/03-2007/08 includes the OM&A expense from electric subsidiaries. 2008/09 Actual data as per CAC/MSOS/MH I-128 from the 2010/12 GRA and does not include the electric subsidiary portion of OM&A.

REFERENCE: Page 50, Capital Spending

QUESTION:

a) Please update your analysis on regular capital spending incorporating the capital spending now forecast in CEF10 and provide your commentary on the results.

b) Please provide B&M's views on the level of capital spending in light of changes in the non-residential Building Construction Price Index.

ANSWER:

(a) and **(b)**

Table 1 provides an illustration of normal capital spending for CEF02-1; CEF07-1; CEF09-1 and CEF10-1. Table 1 also provides the non-residential building construction price index prepared by Statistics Canada.[1] Messrs Bowman and McLaren have not reviewed the non-residential building construction price index in detail and cannot comment on its reasonableness for evaluating construction costs for major utility projects.

Messrs Bowman and McLaren note the following with respect to the information in the table:

- CEF10-1 shows continued upward pressure on Hydro's normal capital spending relative to CEF09-1.

- Over the period from 2002 through 2009 Hydro's normal capital spending compares favourably with the non-residential building construction price index, although the following points are noted:
  - Hydro's definition of major generation and transmission projects changed between CEF02-1 and CEF07-1, making comparisons difficult.

1. Information from:
http://www.statcan.gc.ca/pub/62-007-x/2010002/t012-eng.htm
and
http://www40.statcan.gc.ca/l01/cst01/econ144e-eng.htm

- It appears the calculation of the non-residential building construction price index is based on a survey of seven metropolitan areas and that no communities in Manitoba are included.

Table 1
Normal Capital Spending and
Non-Residential Building Construction Price Index[2]

		CEF02-1 2002	CEF07-1 2007	CEF09-1 2009	CEF10-1 2010
1	11-Year Projected Expenditures ($Billion)	4.38	11.61	16.87	16.84
2	Portion for major new generation, transmission and DSM	1.25	7.48	12.33	12.35
3	Portion for for normal capital spending	3.13	4.13	4.55	4.48
4	**Yearly Normal Capital Spending ($Million)**	**285**	**375**	**413**	**448**
5	***Yearly Normal Capital Spending Indexed to CEF02-1***	***100.0***	***131.7***	***145.1***	***157.3***
6	Non-Residential Building Construction Price Index	100.0	136.8	142.0	140.8

[2] Note that CEF10-1 includes 10 forecast years while other capital expenditure forecasts include 11 years. Non-Residential Building Construction Price Index for 2010 is the average of the first two quarters of the year.

REFERENCE: Section 5.0, Page 54; Thermal Plant Costs (COSS)

QUESTION:

a) Please confirm that both Brandon coal costs and natural gas costs are an integral part of MH's dependable energy and both "allow" MH to market additional firm energy.

b) Please confirm that the legislative directive to limit the future use of the Brandon coal unit specifically precludes MH from using it to meeting firm export as well as domestic load shortfalls.

c) Please confirm that in 2003/04, MH did not rely on natural gas generation to offset a domestic load shortfall and relied almost exclusively on imports to meet that need.

d) Please explain why export contract volumes defined by natural gas generation capacity should not bear most of the fixed cost of the natural gas when in 8 of 10 years it came about due to the presence of the physical gas plants.

ANSWER:

(a) through **(d)**

Messrs Bowman and McLaren understand that pursuant to section 16 of the *Climate Change and Emissions Reductions Act*, after December 31, 2009 Manitoba Hydro must not use coal to generate power, except to support emergency operations. Messrs Bowman and McLaren understand emergency operations is further defined by regulation under the Act but have not specifically reviewed the definitions in the regulation. Messrs Bowman and McLaren are relying on Hydro's interpretation of the legislation that it can no longer use coal-fired generation to support exports (PCOSS11 page 2).

On that basis, assignment of costs should follow the manner in which the system is planned and operated. If the primary or exclusive beneficiaries of the availability of coal generation in emergency conditions are domestic ratepayers then the allocation of those costs to domestic ratepayers is reasonable.

With respect to natural gas generation, Messrs Bowman and McLaren cannot comment on the specific supply sources used by Manitoba Hydro in 2003/04. However, Messrs Bowman and McLaren understand that natural gas generation is available to support export and domestic loads both for planning and operating purposes. On that basis, Messrs Bowman and McLaren recommend that the costs of the natural gas facilities be allocated to all customers (both export and domestic) as an improvement on the current PCOSS11 methods.

However, Messrs Bowman and McLaren also note that any changes to the treatment of thermal costs are not likely to dramatically impact the PCOSS11 results and therefore PCOSS11 still provides useful information for rate setting purposes.

REFERENCE: Section 5.0, Page 55; DSM Cost Allocation (COSS)

QUESTION:

a) Please confirm that DSM activities allow additional (annual) export contract sales and also allow additional opportunity sales in most years.

b) Please explain the reason DSM evaluations typically employs MC or an average of prior year firm exports prices to define the economic viability of DSM activities.

c) Please confirm that the specific DSM cost is justified by the sale of additional export energy.

d) Would B&M favor a DSM subsidy program funded in part or entirely by exports for:

I. Low income residential DSM?
II. Other residential DSM?
III. Commercial DSM?
IV. Industrial DSM?

ANSWER:

(a)

Not confirmed. DSM activities provide Hydro with power supply resources (avoided load) that are in most respects analogous to any other power supply resource serving overall Manitoba Hydro loads, not specifically any one load (such as exports).

(b) and **(c)**

DSM evaluations typically employ MC to define the economic viability, as this is the appropriate approach to assess any new power supply resource option. Any DSM activity is justified if (a) it has a positive business case when comparing costs against benefits (where benefits tend to be largely added export revenues) and (b) it has the most attractive business case of the comparable power resource options available.

(d)

Messrs Bowman and McLaren are of the view that viable DSM projects do not require any form of subsidy; they are appropriate power resource options to pursue the same as any utility-funded supply option.

In this proceeding there is a separate focus on uneconomic energy efficiency projects perceived to have a social value. These do not fit within the normal framework for DSM as a power resource option, and as such must be assessed on some other basis consistent with broad government social policy and welfare considerations.

REFERENCE: Section 5.0, Page 56; Trading Desk Costs (COSS)

QUESTION:

a) Please confirm that over the longer run, MH only requires imports to meet domestic load in 1 or 2 years out of 10 and that in 8 or 9 years out of 10, MH employs imports to boost export sales.

b) Please explain how MH directly attributed trading desk/MAPP/MISO costs to exports; imports to facilitate exports; and imports to serve domestic shortfall.

ANSWER:

(a)

Not Confirmed.

Over the long run, MH only requires imports to meet domestic load in 1 or 2 years out of 10 and that in 8 or 9 years out of 10 MH employs imports to boost export sales. Based on a review of Table 1a System Firm Energy Demand and Dependable Resources (GW.h) – for the Recommended Development Plan the 2009/10 Power Resource Plan (Appendix 47), it appears the sum of imports plus the exportable surplus exceeds dependable exports in each year except 2014/15. On this basis one might conclude imports are not required for domestic purposes.

However, Messrs Bowman and McLaren understand there are other reasons for pursuing imports including seasonality and timing requirements and economic reasons (for example if imports can be acquired at lower costs than domestic based thermal resources).

(b)

Messrs Bowman and McLaren did not review and cannot comment on the specific methods used by Hydro to directly assign a portion of trading desk, MAPP and MISO costs to exports. Messrs Bowman and McLaren reviewed the discussion on pages 2 and 3 of PCOSS11. Hydro's discussion that trading desk, MISO and MAPP membership provides benefits to domestic customers seems reasonable and therefore apportioning some of these costs to domestic customers is consistent with cost causation principles. Further, Messrs Bowman and McLaren note the dollar value of costs involved are small and changes are unlikely to materially affect the outcome of the cost-of-service study.

REFERENCE: Section 5.0, Page 58; Table 5.1 – Levelized RCC/KWh

QUESTION:

a) Please provide an expanded version of Table 5.1 also showing:
   I. GSS-D
   II. GSL<30
   III. GSL 30-100
   IV. Domestic total

b) Please explain why the sub-transmission cost is separately defined for each domestic classes when MH typically includes this in distribution subtotal.

ANSWER:

(a)

Copies of the requested Table and Figure expanded to show all rate classes and domestic totals are provided below. The diesel class was excluded from the figure in order not to compress the vertical axis of the chart.

(b)

Sub-transmission costs were separately defined in order to illustrate the distinction between customers served at transmission voltage (exports and GSL<100kV) who do not make use of sub-transmission assets and other customer classes. The GSL<100kV class also generally do not make use of the distribution system, except for some small costs primarily related to customer service functions functionalized to distribution.

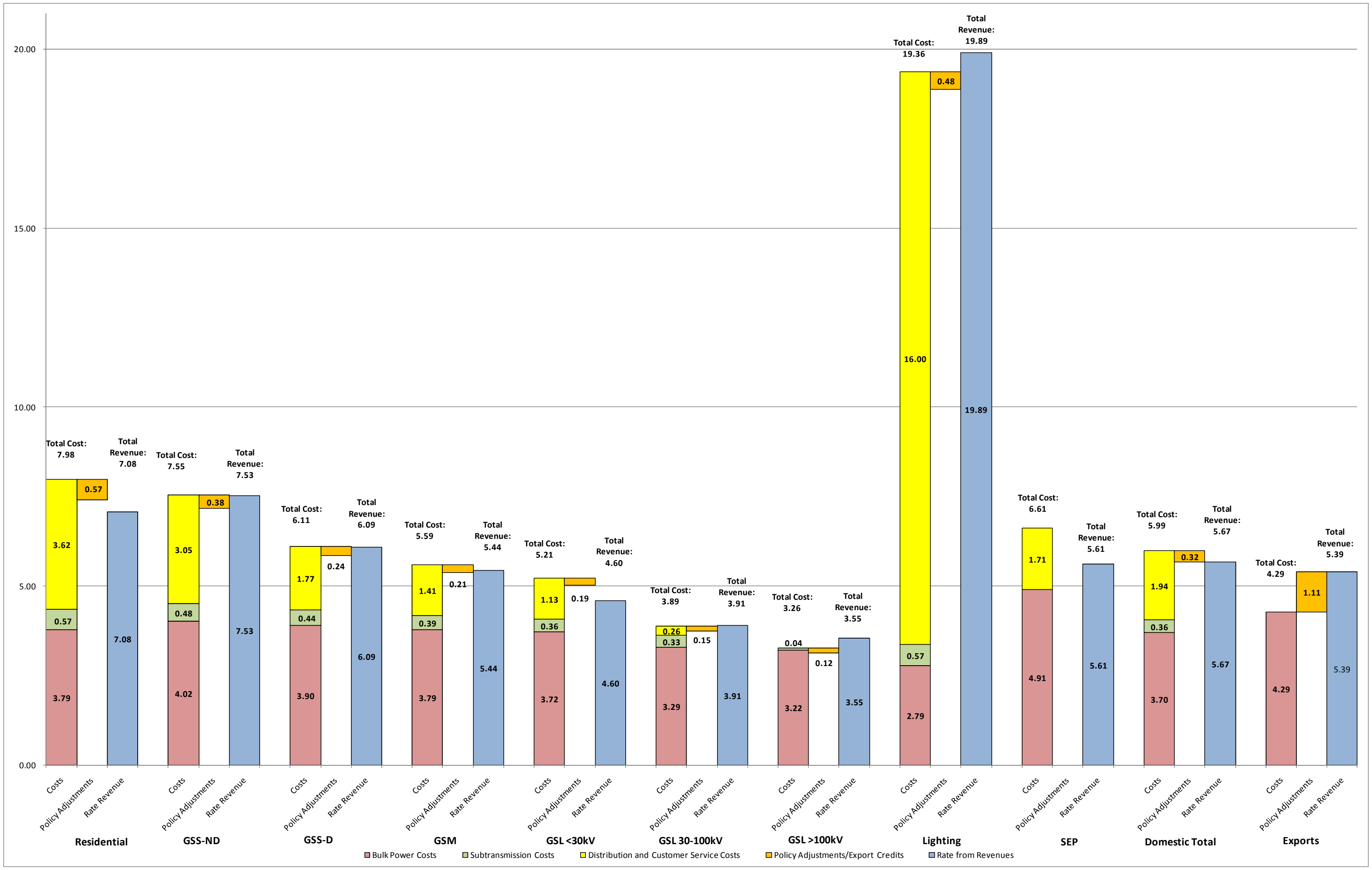
Levelized RCC Ratios per kW.h PCOSS11

	Residential		GSS-ND		GSS-D		GSM		GSL<30kV		GSL 30-100kV		GSL>100kV	
	($ M)	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)
Costs														
1 Bulk Power Costs	*$256.32*	3.79	*$63.19*	4.02	*$73.39*	3.90	*$114.28*	3.79	*57.22*	3.72	*27.90*	3.29	*171.02*	3.22
2 plus: Subtransmission-related	*$38.75*	0.57	*$7.58*	0.48	*$8.34*	0.44	*$11.70*	0.39	*5.53*	0.36	*2.78*	0.33	*0.00*	0.00
3 plus: Distrib. and Cust. Serv.	*$245.29*	3.62	*$47.87*	3.05	*$33.24*	1.77	*$42.48*	1.41	*17.45*	1.13	*2.24*	0.26	*2.32*	0.04
4 Total Costs	***$540.37***	**7.98**	***$118.64***	**7.55**	***$114.98***	**6.11**	***$168.45***	**5.59**	***80.20***	**5.21**	***32.91***	**3.89**	***173.34***	**3.26**
Rates														
5 Total PCOSS Sales Revenue	***$479.64***	**7.08**	***$118.33***	**7.53**	***$114.72***	**6.09**	***$164.08***	**5.44**	***70.73***	**4.60**	***33.07***	**3.91**	***188.68***	**3.55**
Surplus/Shortfall before Net Export Credits														
6 Rates compared to costs (5-4)	***($60.72)***	**-0.90**	***($0.31)***	**-0.02**	***($0.26)***	**-0.01**	***($4.38)***	**-0.15**	***($9.47)***	**-0.62**	***$0.16***	**0.02**	***$15.34***	**0.29**
7 Revenue:Cost Ratio (Net of Policy Adjustments and Export Credits) (line 5/ line 4)	***88.76%***		***99.74%***		***99.78%***		***97.40%***		***88.19%***		***100.47%***		***108.85%***	
Policy Adjustments														
8 Uniform Rate Credit	*$17.81*	0.26	*$1.58*	0.10	*$0.37*	0.02	*$0.04*	0.00	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00
9 Affordable Energy Fund Expenditures	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00
10 Net Export Revenue Allocation	*$20.54*	0.30	*$4.38*	0.28	*$4.22*	0.22	*$6.24*	0.21	*$2.96*	0.19	*$1.24*	0.15	*$6.50*	0.12
11 Surplus/(Shortfall) after net export revenue credits (6+8+9+10)	***($22.38)***	**-0.33**	***$5.66***	**0.36**	***$4.33***	**0.23**	***$1.90***	**0.06**	***($6.51)***	**-0.42**	***$1.40***	**0.16**	***$21.84***	**0.41**
12 Total Class Metered Energy (GW.h)	*6,772*		*1,571*		*1,883*		*3,015*		*1,539*		*847*		*5,311*	

	Lighting		SEP		Diesel		Domestic Total		Exports	
	($ M)	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)	*($ M)*	(¢/kWh)
Costs										
1 Bulk Power Costs	*$2.82*	2.79	*$0.75*	4.91	*$11.67*	85.38	*$778.55*	3.70	*$305.23*	4.29
2 plus: Subtransmission-related	*$0.58*	0.57	*$0.00*	0.00	*$0.00*	0.00	*$75.26*	0.36	*$0.00*	0.00
3 plus: Distrib. and Cust. Serv.	*$16.18*	16.00	*$0.26*	1.71	*$0.71*	5.19	*$408.04*	1.94	*$0.00*	0.00
4 Total Costs	***$19.57***	**19.36**	***$1.01***	**6.61**	***$12.38***	**90.57**	***$1,261.85***	**5.99**	***$305.23***	**4.29**
Rates										
5 Total PCOSS Sales Revenue	***$20.11***	**19.89**	***$0.85***	**5.61**	***$4.79***	**35.08**	***$1,195.01***	**5.67**	***$384.06***	**5.39**
Surplus/Shortfall before Net Export Credits										
6 Rates compared to costs (5-4)	***$0.54***	**0.53**	***($0.15)***	**-1.01**	***($7.58)***	**-55.49**	***($66.84)***	**-0.32**	***$78.84***	**1.11**
7 Revenue:Cost Ratio (Net of Policy Adjustments and Export Credits) (line 5/ line 4)	***102.73%***		***84.79%***		***38.73%***		***94.70%***		***125.83%***	
Policy Adjustments										
8 Uniform Rate Credit	*$0.23*	0.23	*$0.00*	0.00	*$0.00*	0.00	*$20.03*	0.10	*($20.03)*	-0.28
9 Affordable Energy Fund Expenditures	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00	*$0.00*	0.00	*($12.00)*	-0.17
10 Net Export Revenue Allocation	*$0.26*	0.26	*$0.00*	0.00	*$0.48*	3.49	*$46.81*	0.22	*($46.81)*	-0.66
11 Surplus/(Shortfall) after net export revenue credits (6+8+9+10)	***$1.02***	**1.01**	***($0.15)***	**-1.01**	***($7.10)***	**-52.00**	***($0.00)***	**-0.00**	***($0.00)***	**-0.00**
12 Total Class Metered Energy (GW.h)	*101*		*15*		*14*		*21,067*		*7,122*	

1 **Customer Class Costs and Revenues for PCOSS11 Data**

2



3

REFERENCE: Section 6.1, Page 64; Demand Concessions/Winter Ratchet

QUESTION:

a) Please provide the details that illustrate:
   I. Winter ratchet delay extra revenues
   II. Demand concessions potential revenue losses

b) Does MIPUG see a need for an ongoing demand adjustment process to cushion individual industrial customers from adverse business cycles?

ANSWER:

(a)

Manitoba Hydro's response to MIPUG/MH I-21(d) ii indicates the savings to GSM and GSL customers had the winter ratchet been eliminated effective June 1, 2009 as opposed to December 1, 2009. The sum of the potential savings is approximately $3.24 million. The same response indicates that savings to the GSM and GSL customers, had the winter ratchet been removed October 1, 2009 instead of December 1, 2009, would be approximately $1.04 million.

Messrs Bowman and McLaren note several estimates of the cost of the demand concession program on the record. Appendix 13.1 indicates estimated costs of $2.022 million.

(b)

Messrs Bowman and McLaren are of the view that Manitoba Hydro's demand billing concession program temporarily mitigated a long-standing deficiency in the GSL rate design. Future improvements to demand-related price signals to reduce the potential for this adverse rate impact are properly addressed as part of the ongoing industrial rate design discussions that are presently underway.

REFERENCE: B-1 to B-7

QUESTION:

a) Please provide tables of the respective data points for each of the figures.

b) Please provide B&M's understanding about the appropriate relationship between MH's
   I. Retained earnings
   II. Total debt
   III. Debt ratio

ANSWER:

(a)

Please refer to the tables provided below.

(b)

It is unclear what is intended with respect to the "appropriate relationship" between Manitoba Hydro's retained earnings, total debt and debt ratio. The relationship between these values is mathematical (e.g., total capital is comprised of debt and retained earnings).

As to what is the appropriate debt ratio for Hydro, Messrs Bowman and McLaren have focused on relevant metrics for regulation of Hydro; as identified in previous evidence from Bowman and McLaren (e.g., the 2008 GRA), a debt:equity target is a metric that poorly suits a regulatory forum. A more appropriate metric is determining the level of reserves and annual contribution to reserves from rates that can support with a high likelihood the ability to maintain a stable and predictable rate regime. In this GRA, the focus of most major risk reports (KPMG, ICF) is on ensuring funds contributed by ratepayers (i.e., Hydro's retained earnings) achieve sufficient capital to achieve a level representative of the costs of a 5 year benchmark drought. This is consistent with the approach adopted in recent Hydro GRAs, which the Bowman and McLaren evidence notes (at page 4). This approach is appropriate for the Board to continue with for the time being.

ANSWER:

(a)

Consolidated Debt Ratio (Figure B.1-1)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
IFF07-1						78%	78%	78%	78%	78%	78%	78%	78%	78%	78%	77%		
IFF09-1								74%	75%	76%	76%	78%	79%	80%	80%	80%	80%	80%
IFF10-1									74%	74%	76%	77%	77%	78%	80%	80%	80%	81%
Actuals	80%	87%	85%	81%	80%	73%	77%	73%										
Target	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%

Electric Retained Earnings (Figure B.1-2)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
IFF07-1						$1,735	$1,891	$1,996	$2,112	$2,226	$2,326	$2,455	$2,623	$2,854	$3,093	$3,349		
IFF09-1								$2,183	$2,261	$2,331	$2,403	$2,528	$2,641	$2,889	$3,153	$3,388	$3,632	$3,908
IFF10-1									$2,354	$2,479	$2,595	$2,779	$2,922	$3,139	$3,406	$3,679	$3,904	$4,196
Actuals	$1,135	$707	$845	$1,265	$1,386	$1,795	$2,084											

Electric Operations Revenues (Figure B.2-1)

Domestic Revenues:

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
IFF07-1						$1,057	$1,117	$1,194	$1,254	$1,305	$1,358	$1,413	$1,469	$1,527	$1,586	$1,653		
IFF09-1								$1,160	$1,192	$1,246	$1,304	$1,365	$1,441	$1,510	$1,582	$1,653	$1,726	$1,805
IFF10-1									$1,194	$1,265	$1,322	$1,389	$1,451	$1,518	$1,591	$1,661	$1,736	$1,818
Actuals	$875	$918	$939	$984	$1,024	$1,075	$1,127											

Export Revenues:

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
IFF07-1						582	468	416	415	471	537	550	573	636	645	679		
IFF09-1								414	383	554	583	615	590	701	729	742	894	1093
IFF10-1									444	461	499	510	529	611	621	646	654	804
Actuals	463	351	554	827	592	625	623	427										

1 **Electric Cumulative Rate Increase (Figure B.2-2)**

2

3

	IFF07-1	IFF09-1	IFF10-1	Actuals
2003				
2004				-0.72%
2005				4.25%
2006				6.59%
2007				8.99%
2008	8.99%			8.99%
2009	12.15%			14.44%
2010	15.40%	17.76%		17.76%
2011	18.75%	21.18%	21.06%	
2012	22.20%	24.69%	24.50%	
2013	25.74%	29.05%	28.86%	
2014	29.39%	33.57%	33.37%	
2015	33.14%	38.25%	38.03%	
2016	37.00%	43.08%	42.86%	
2017	40.97%	48.09%	47.86%	
2018	45.06%	53.28%	53.04%	
2019		58.64%	58.40%	
2020		64.19%	63.94%	

Electric Net Plant in Service (Figure B.3-1)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
IFF07-1						$7,226	$7,528	$7,568	$7,633	$9,326	$9,319	$9,327	$9,265	$10,036	$9,912	$11,997		
IFF09-1								$7,865	$8,015	$9,677	$9,761	$9,765	$10,042	$10,035	$10,297	$12,292	$13,085	$15,950
IFF10-1									$7,815	$9,419	$9,520	$9,656	$10,412	$10,526	$10,623	$12,535	$12,826	$16,108
Actuals	$6,613	$6,819	$6,956	$7,053	$7,134	$7,321	$7,684											

Electric Operations, Maintenance & Administration Expense (Figure B.4-1)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
IFF02-1	$283	$303	$304	$307	$313	$319	$326	$332	$340	$347	$353							
IFF03-1		$304	$307	$309	$315	$321	$330	$337	$348	$355	$362	$370						
IFF04-1			$307	$318	$324	$332	$341	$349	$362	$369	$378	$386	$393					
IFF05-1				$322	$332	$339	$338	$345	$352	$365	$372	$380	$387	$395				
IFF06-4					$339	$356	$356	$363	$370	$377	$391	$399	$407	$415	$423			
IFF07-1						$351	$360	$369	$377	$389	$398	$406	$415	$423	$431	$453		
IFF08-1							$349	$358	$365	$379	$386	$394	$402	$410	$418	$439	$450	
IFF09-1								$372	$380	$403	$411	$420	$428	$437	$445	$467	$478	$497
IFF10-1									$398	$402	$414	$422	$430	$439	$448	$469	$478	$495
Actuals	$272	$293	$308	$322	$332	$335	$360											

REFERENCE: B.1-1 Debt Ratio

QUESTION:

a) To what extent did B&M's analysis take into account the inclusion/exclusion of Accumulated Other Comprehensive Income (AOCI) in the determination of the ratio.

ANSWER:

(a)

The forecast values in the cited figure are based on IFF data, and do not make any adjustments for AOCI. As noted in CAC/MSOS/MH-I-116(b), this means that AOCI is effectively included as a component of equity in these values (where previously this component was not included in the debt:equity ratio calculations, or was not measured).

Actual values in the figure are from Appendix 63, Hydro's annual report for the year ending March 31, 2010. Note that although footnote 2 on page 100, does not indicate AOCI is included in the calculation of the debt ratio in this source, the debt ratio values are consistent with CAC/MSOS/MH-I-116(c) which does specifically include AOCI.

Although the above approach permits consistency with Hydro data (in that equity is inclusive of unrealized gains and losses on foreign exchange as the apparent largest component of AOCI), the relevance of this approach, given the presence of a long-term exposure management program, is debatable. In particular it is noted that AOCI can cause considerable instability in the measured equity levels (with changes in AOCI in some years being in excess of net income[1]).

[1] For example, between 2007/08 and 2008/09, the AOCI value changed $474 million.

MANITOBA HYDRO
(MH)