PRE-FILED TESTIMONY OF

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IN REGARD TO MANITOBA HYDRO 2010/11 and 2011/12

GENERAL RATE APPLICATION

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

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1.0 INTRODUCTION

This testimony has been prepared for the Manitoba Industrial Power Users Group ("MIPUG") by InterGroup Consultants Ltd. ("InterGroup") under the direction of Mr. P. Bowman with the assistance of Mr. A. McLaren. MIPUG's current membership and concerns are outlined in Section 1.2. The qualifications of Mr. P. Bowman and Mr. A. McLaren are provided in Attachment A.

InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's ("Hydro") 2010/11 & 2011/12 General Rate Application ("Application" or "GRA") that are of interest to industrial customers. In particular, the scope of the review includes the following, taking into account normal regulatory review procedures and principles appropriate for Canadian Crown-owned electric utilities:

- Financial performance from the time of the last Public Utilities Board ("PUB" or "Board") review, forecast financial performance within Hydro's current projections, necessary levels of reserves and the rate of progress in establishing reserves, and appropriate overall rate adjustments that should be required in light of these financial results.

- Cost of Service Study ("COSS") methods and results.

- Proposed rates for general consumers and in particular industrial customers.

In preparing this testimony, the following information has been reviewed:

- The Hydro GRA dated November 30, 2009, including appendices, and the responses to the Information Requests to Hydro (including the report on risk prepared by ICF International ("ICF").

- To a limited extent, Hydro's evidence in the 2008 GRA proceeding, the 2006 Cost of Service proceeding and earlier rate hearings as they relate to the current proceeding.

- The major risk reports made available pursuant to Board Order 97/10 (including in particular Appendix H - the KMPG LLP report on risk ("KPMG").

- The reports of the Board appointed Independent Consultants, Drs Kubursi and Magee ("KM Report").

The hearing record in this proceeding is a massive volume of information. Consequently, the review of this material was of necessity focused on key issues of concern.

The evidence is presented in the following sections:

- Section 2 provides an overview of Hydro's filing and requested approvals.

- Section 3 reviews issues of risk in relation to Hydro's rates.

- Section 4 provides a review of financial results and forecasts.

- Section 5 provides a review of the Cost of Service study and rates for general consumers.

- Section 6 provides a review of industrial, cost-based rate design.

1.1 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

In its argument in the 2008 GRA, MIPUG concluded "...it is becoming necessary within the Board's jurisdiction for the Board itself to convene a serious review of Hydro's risks" in relation to long-term rate stability[1]. The present review fulfills this earlier recommendation.

In particular, this proceeding is rooted in the confluence of rate related topics from the very precise near term (the level of rates to be approved for 2010 and 2011) to broad, foundational long-term topics (the core rational for Manitoba's approach to power system development, past and future). Each relates directly to concepts of risk and opportunity.

Hydro is at a critical juncture in its evolution. Over the past 2 to 3 decades, Manitoba Hydro has changed from a utility with a specific focus on planning for a largely isolated Manitoba domestic power system, to an active participant in an integrated extraprovincial marketplace, linked both physically and financially to external markets. This evolution has provided substantial benefits for ratepayers. In this GRA filing, Hydro sets out its recommended planning focus for the next two decades of activities: first, the decade of investment where a new generation of major capital projects being planned are expected to come into service (including further integration with extraprovincial markets), followed by the decade of returns that begin to arise for ratepayers from these investments. The alternative to this major commitment is a less ambitious, more domestically focused scenario. The risk profiles of the two options materially differ.

Against this backdrop, this submission concludes that, at its core, Hydro possesses a stable risk management regime adequate to the task of addressing the risks inherent in its operations, with an advantageous complement of assets and what appears to be a well-founded recommended development concept that appropriately responds to the long-term risks that lie ahead. Ongoing cost control continues to be problem for Hydro, and Manitoba's regulatory tools as presently applied are proving insufficient to encourage Hydro's consideration of the Board's previous recommendations in this regard. Hydro's Cost of Service Study is a reliable product, and Hydro's proposals for rate design structure in this proceeding are appropriate particularly in light of ongoing orderly cooperative initiatives to evolve the industrial rate design, for future consideration by the Board). The overall level of rates recommended by Hydro for the test years are within a predictable range and as such are reasonable, with the sole caveat being a possibly greater need for sensitivity to present economic circumstances adversely affecting some of Hydro's longstanding customers.

[1] MIPUG Final Argument in the 2008 GRA, exhibit MIPUG-17, at page 9-3.

This submission address the following specific conclusions and recommendations[2]:

1) In regard to **risk management practices**, specific improvements to Hydro's systems have been recommended in the various reports filed with the Board. The Board should ensure Hydro has reviewed these recommendations and made appropriate plans to adopt the recommendations determined to be relevant. Beyond this, Hydro's management must be left to practically fulfill their responsibilities for running the utility (in a manner that is appropriately accountable to the Board in relation to rates).

2) In regard to **risk tolerance**, the key benchmark for Hydro's willingness to accept risk in the operation of its system must be the risk tolerance of its Manitoba ratepayers (i.e., not the shareholders or citizens generally, to extent these tolerances may differ). In all material respects, the evidence in this proceeding confirms Hydro's thresholds in this regard are appropriate. The Board should not accept the suggestions of the KM Report in regard to new added "water in storage" overrides, nor alterations to the "objective functions" in Hydro's short term scheduling model (MOST) (proposed by the KM Report to target minimized generation cost, as opposed to the current target of maximized net revenues).

3) In regard to **quantification of risk**, there appears to be effectively no disagreement among the major risk report authors as to the cost of Hydro's major risk – drought. Each of the reviews effectively confirms Hydro's estimates of the financial effects of droughts of varying duration.

4) Given the noted quantification of risk, the consequent **level of required financial reserves** has three competing frameworks:

    a) The existing framework for target reserve levels is effectively equal to the benchmark five year drought. Hydro, ICF and KPMG all retain this concept. It would be acceptable for the Board to continue with this technique. In the present circumstances, this is roughly equivalent to a 75:25 debt:equity ratio (however, in the latter years of the IFF period the 75:25 ratio may exceed the calculated cost of a five year drought at that time).

    b) The KM Report instead recommends what appears to be a materially higher target financial reserve level (approximately double the existing standard). This recommendation is not consistent with any past practice in Manitoba, or with the

[2] At the outset, it should be noted that none of the major reports concluded any merit to the sensational claims of mismanagement, blackouts and unnecessary billion dollar losses contained in the former Manitoba Hydro consultant ("NYC") allegations, as provided for review in this proceeding .

fundamental framework for public power development focused on the long-term, and as such should not be accepted by the Board.

c) Should a more refined financial reserve target be desired in future (for example, in order to confirm a future ability to back-off rate pressures as adequate reserve levels are approached), this type of value may suitably be derived based on targeting a long-term rate stability criteria (encompassing periods leading up to, during, and following a benchmark drought)[3]. Such an analysis could be completed on a probabilistic basis using selected portions of the analytical tools identified in the KM Report.

5) On the **form of financial reserves**, the evidence on risk in this proceeding does not materially advance the discussion in regard to regulated reserves. This is not surprising as the core principles required to address this issue are regulatory in nature, not the expertise of risk practitioners. Consistent with the concept of an orderly process to address issues raised by the Board, the present proceeding can serve to give comfort regarding identification, management and quantification of risks, permitting progression to the matter of addressing the form of reserves as a future next step. There is no basis to accept recommendations today that any new rate riders are required to establish emergency funds for special “drastic” situations.

6) In regard to Hydro’s **financial forecasts**, sustained upward pressure remains evident in Hydro’s cost forecasts (both OM&A and “normal” capital spending) including apparent new increases as compared to the last GRA. The Board must continue to encourage restraint in these areas. Additionally:

a) The implementation by Hydro of the Board’s previous and longstanding recommendations regarding cost control (and expeditious improvement in Hydro’s debt load) continues to be hampered by the limited regulatory tools applied in Manitoba. In particular, it is noted that the Board largely only sets Hydro’s rates (and through this route affects Hydro’s revenues). With risks and reserve levels as a key item of regulatory concern, the Board’s decisions on rates continue to have an insufficient linkage to the level of Hydro’s reserves. When Hydro’s costs (notably OM&A) escalate beyond levels with which the Board ought to have comfort (as they have in most recent forecasts for the last decade), any higher rates approved by the Board for the purposes of building protection for ratepayers in the form of reserves do not in fact arise as reserves, as intended. In this situation, the Board is caught between raising rates further, which

[3] Such a value could be derived in terms of calculating the required starting value of reserves in order to ensure a high probability of being able to maintain stable rates over the long-term under all reasonably foreseeable variations in conditions.

simply reaffirms Hydro's cost levels, or cutting rates, which is not prudent in light of the Board's apparent view of Hydro's present reserve levels. For the reason the "form of financial reserves" discussion (as noted above) pertains not only to risk mitigation, but also to the benefit of practical regulatory control.

b) With the proposed massive level of investment, it is timely and appropriate for Hydro to seek agreement from the Province that it no longer requires a sinking fund obligation on new borrowings. This change would not only reduce overall costs to ratepayers, it can have a beneficial role in avoiding added risks to Hydro from yield spreads on sinking funds in relation to the underlying debt instrument. The Board should direct Hydro to seek the provincial government's repeal of the requirement for sinking funds contributions contained in the *Manitoba Hydro Act*.

7) With respect to **cost of service and rate design,** following a period of intense scrutiny, public review, and refinement since 2004, Hydro's Cost of Service ("COS") methodology can be confirmed as reasonable. The results can provide the Board with comfort that it has appropriate and adequate information to make decisions regarding relative rate adjustments between the various classes. The uncertainty which existed over the past series of proceedings has been resolved[4] and the result permits useful, reliable analysis to be performed. Additionally:

a) For this proceeding, a 2.9% benchmark rate increase in the test years can be justified, primarily to establish a measured predictable rate adjustment regime. Any future overall increases to the level of Hydro's rates should be predicated on completing the present risk review, to confirm confidence in Hydro's risk management and quantification, and orderly progress towards the establishment of a more appropriate regulated reserve framework.

b) The specific level of rate adjustments to each of the various classes should reflect the results of the COS analysis, focused primarily on revenue:cost ratios absent net export credits or other past policy-related allocations. Customers whose rates sufficiently cover the costs (6 of the 9 major classes) may appropriately be assigned rate adjustments at the benchmark level (2.9%). Priority consideration should be given to modestly higher rate adjustments to the classes who remain well below the measured level of the costs to serve their loads[5].

[4] This is not to say that there does not remain some level of disagreement regarding the methodologies employed in the Cost of Service study. However, as these issued were extensively debated before the Board and the methodology was only recently confirmed, these issues are not suitably front-and-center in the present proceeding.

[5] Such class adjustments should conform with Hydro's general ratemaking objective of being within 2% of the overall corporate-wide average rate adjustment.

c) Hydro's proposal to finalize the Temporary Billing Demand Concession Program initiated in Order 126/09, by way of "making permanent, billing concessions granted under such program"[6] should be accepted.

Other recommendations or observations are contained in the appropriate sections of this submission.

1.2 OVERVIEW OF MIPUG MEMBERSHIP AND CONCERNS

MIPUG is an association of major industrial companies operating in Manitoba. The purpose of the association is to work together on issues of common concern related to electricity supply and rates in Manitoba. To that end, MIPUG intervened in each of the Board's reviews of Hydro rates since 1988, as well as the Board's review of the Centra Gas acquisition in 1999 and Hydro's Major Capital Projects in 1990.

MIPUG membership currently includes the following companies:

- Canexus Income Fund (Brandon);
- Vale Inco Limited (Thompson);
- HudBay Minerals Inc. (Flin Flon);
- Enbridge Inc. (Southern Manitoba);
- Gerdau Ameristeel Corporation (Selkirk);
- ERCO Worldwide (Hargrave);
- Koch Industries, Inc. (Brandon);

[6] 20010/11 and 2011/12 GRA filing, Tab 1, Page 2.

- Tolko Industries, Ltd. (The Pas);

- Griffin Wheel Company (Winnipeg); and

- TransCanada Corporation (Southern Manitoba).

In 2008, MIPUG provided an update to its 2005 economic impact study[7] of member companies. According to the information available at the time the economic impact study was undertaken, MIPUG members employed over 4,500 people, had a replacement value of their assets in Manitoba of over $2 billion, and sold over 90% of the products they produce outside of Manitoba.

In previous interventions, MIPUG members, as major power users, have consistently expressed concern about the long-term interests of Hydro's domestic customers with respect to the following items:

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

- The need for strong regulatory oversight and approval of all rates charged by Manitoba Hydro.

- Consistent focused on the need to consider long-term system planning and rate issues with attention to the need to ensure Hydro's investments promote rate stability and predictability over the long-term.

- Protection for domestic customers against higher rates or risks caused by Hydro's investments in subsidiaries, new export ventures or major new capital programs that do not promote least-cost long-term rates for the utility's domestic electricity customers.

- Protection for domestic customers against changes in government charges for items such as water rentals, debt guarantees or any other policy-related factors that increase the general rates charged to domestic customers.

- Assurance that general customer rates are reasonable within the context of long-term cost projections and provision of secured financial reserves that are appropriate in light of Hydro's past practice and the specifics of the Manitoba market.

[7] The Economic Impact of The Manitoba Industrial Power Users Group. Provided in response to PUB/MIPUG-1 from the 2008 GRA proceeding.

- Assurance that rates to each customers class reflect Cost of Service calculated in accordance with principles appropriate to Canadian regulatory practice for Crown electric utilities.

MIPUG members' concerns are reflective of the size of their capital investments in Manitoba, the long-term perspective essential to such investments and the major stake that these investments typically have in continued large-scale power purchases from Hydro. In addition, MIPUG members' concerns reflect competitive market pressures associated with selling Manitoba industrial products to external markets and the need to secure the lowest reasonable costs for power, as well as other production inputs, to offset disadvantages that arise from operations in Manitoba such as transportation and distance to markets.

2.0 OVERVIEW OF APPLICATION

Hydro's November 30, 2009 filing seeks approval of across the board general consumer rate increases of 2.9% effective April 1, 2010 yielding $33.4 million in additional revenue and a further 2.9% effective April 1, 2011 yielding additional revenue of $35.1 million[8]. Hydro's filing notes it achieved its 75:25 debt to equity ratio target in 2008/09. However, Hydro indicates its revenue forecasts have declined since the last GRA, owing largely to reduced domestic load forecasts and reduced export market prices[9]. In support of the requested rate increases Hydro cites that "The proposed rate increases reflect the appropriate balance between customer sensitivity and fiscal responsibility. In consideration of the economic downturn and its effects on ratepayers, 2.9% increases in each of the next two years are considered to be reasonable"[10].

Hydro's application characterizes the ten-year period to 2020 as "the decade of investment" involving major investments in capital projects. This decade of investment drives the requirement for the current 2.9% rate increase requests, as well as a further projection of 3.5% annual increases through the remainder of the forecast period. Hydro refers to the decade following 2020 as the "decade of returns" in which significant benefits are returned to energy ratepayers of Manitoba as a result of Hydro's recommended power resource plan[11] (lower forecast rate increases equalling the level of inflation, assumed at 2%, with material growth in reserves to approximately the 51:49 debt:equity level by the end of the decade)[12].

Manitoba Hydro received interim approval for the first of the proposed 2.9% general consumer rate increases[13] effective April 1, 2010 in a majority Board Decision. One Board member dissented, declining to support an interim rate award noting that Hydro "...is the author of its own misfortunes with respect to the timetable that now exists"[14].

Hydro also seeks final approval for various interim orders related to the Surplus Energy Program and the Curtailable Service Program, as well as final approval of the billing concessions granted to certain General Service Large and General Service Medium customers under Order 126/09 as permanent.

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[8] Manitoba Hydro 2010/11 and 2011/12 GRA, Tab 1 page 2.
[9] Manitoba Hydro 2010/11 and 2011/12 GRA, Tab 2 page 2.
[10] Manitoba Hydro 2010/11 and 2011/12 GRA, Tab 1 page 2.
[11] Manitoba Hydro's recommended development plan is discuss in the 2009/2010 Power Resource Plan, see tables provided at pages 12-19; this is discussed in the KPMG report as Hydro's "preferred development plan" in section 4.10.1.
[12] Manitoba Hydro 2010/11 and 2011/12 GRA, Tab 2 page 3.
[13] Excluding Area and Roadway Lighting.
[14] Order 18/10, page 11.

Other items of particular note included in Manitoba Hydro's Application include:

- CEF09-1 indicates forecast capital expenditures for the period through 2019/20 of $16.6 billion. Major new generation and transmission projects make up $12.8 billion of that forecast[15].

- Hydro's 2009 Power Resource Plan adopts a "Recommended Power Resource Development" sequence comprising material added extra-provincial sales, new cross-border transmission and advancement of major new hydraulic generation plants in northern Manitoba. In particular, the plan includes an in-service date of 2018/19 for Keeyask and 2022/23 for Conawapa, 300 MW of additional wind development, and "Additional north-south transmission beyond a 2000 MW Bipole III". Hydro notes this sequence meets the demand of Manitoba domestic load and the new export sales to Wisconsin Public Service, Minnesota Power and Northern States Power pursuant to signed term sheets, as well as an extension of existing export sale and diversity contacts. The result of the recommended development plan shows dependable energy and capacity surpluses for the entire forecast period through 2025/26 both with and without Brandon thermal unit #5.

- The 2009/10 Electric Load Forecast provided as Appendix 7.1 to the Application reflects substantial reductions in GS Top Consumers sales relative to previous forecasts (largely industrial load reductions). By the 2028/29 year, the 2009/10 Electric Load Forecast reflects a reduction of 847 GW.h in Top Consumers sales relative to the 2008/09 forecast (a 10% reduction from the previous forecast) offset in part by increases of 2-3% in residential loads at 2028/29 over the previous forecast, for a net reduced total sales of 588 GW.h. It is not clear that this load forecast incorporates recent information about material pending load reductions in the mining sector load in Thompson. The load forecast also identifies and quantifies material risks related to the potential for added load due to fuel switching for domestic space heating, in the event natural gas prices increase beyond electricity, totaling an added 6000 GW.h/year and 2000 MW at peak in 20 years which is not included in the forecast.

- Manitoba Hydro provides a Prospective Cost of Service Study for the fiscal year ended March 31, 2010 in Appendix 11.1 and for the fiscal year ended March 31, 2011 in Appendix 58. In particular, the 2011 study indicates that 6 of the 9 major classes of customers face rates today that fully cover or exceed the costs to serve them before any net export revenue benefits are applied. Exports continue to yield rates that exceed the embedded costs to serve these sales. While these Cost of Service studies largely reflect past Board Orders and the approved methodologies, Manitoba Hydro recommends these cost-of-service studies be accepted for

[15] Manitoba Hydro 2010/11 and 2001/12 GRA, Tab 6 page 2.

information only due to the fact that Hydro plans to now complete a redevelopment of its COS method via an external review[16].

In addition to the main Hydro documents provided in the GRA filing, the hearing record includes substantial additional information related to the topic of Hydro's risk, comprising a long-list of internal Hydro documents, externally prepared studies on various narrow topics related to risk, plus 2 comprehensive studies commissioned by Hydro in relation to Hydro's risk: (a) a document prepared by ICF International ("ICF") in relation to export power sales and associated risks, and (b) a document prepared by KPMG LLP ("KPMG") providing an independent assessment of Hydro's risk management practices. These reports are now complemented by the report of the Independent Experts retained by the PUB to review Hydro's risk and the related reports. Limited information is available in relation to the work of one of Hydro's former consultants (the "New York Consultant" or "NYC"); what has been made available comprises numerous individual statements made related to Hydro's risk, without backup analysis being available.

[16] Manitoba Hydro 2010/11 and 2011/12 General Rate Application. Tab 11 page 2 lines 10-13.

3.0 REVIEW OF MANITOBA HYDRO RISKS RELATED TO THE 2010/11 GRA

Section 3 responds to the Board's direction in Order 17/10 that "a detailed risk and risk management review will proceed[17]" in relation to the current Manitoba Hydro 2010/11 General Rate Application, and includes the following topics:

- Context for Current Risk Review;
- Board Guidance as to Scoping of this Risk Review and Hydro's Requested Decisions;
- Overview of Materials Filed;
- Risk in Regulatory Ratemaking;
- Specific Risk Topics Relevant to the Board's Review of Hydro Rates; and
- Concluding Comments and Observations.

3.1 CONTEXT FOR CURRENT RISK REVIEW

The current risk review represents an unprecedented regulatory proceeding with an expanded scope beyond that contained in Manitoba Hydro's November 30, 2009 Application for approval of across the Board general consumer rate increases. In undertaking this review in the context of the 2010/11 General Rate Application, it will be important to clarify the relationship between risks and Manitoba Hydro's rates.

The ability of Hydro and its ratepayers to fully address imminent development opportunities and planning decisions must be predicated on a clear and confident understanding of risk, and the utility's ability to manage risk in the interests of ratepayers. The current risk review is therefore most timely.

Of particular note, the long-term future level of Manitoba rates will be materially affected by the commitments occurring in the next few years. Material commitments must be made in a relatively short-period by various key parties to a specific discrete development sequence for Manitoba Hydro[18]. At a summary level, the Application indicates as follows:

[17] See page 11.

[18] The CEF09 indicates construction commitments to major components of the preferred development sequence such as materially increased spending commitments to Keeyask by 2012, Conawapa and new cross-border transmission by 2014.

- In the period to 2020 Hydro has set out a Capital Expenditure Forecast[19] in the Application that incorporates Hydro's recommended power resource plan requiring expenditures or commitments to over $15 billion in major new or enhanced generation and transmission facilities, as well as major new commitments to long-term dependable export contracts and added integration with export markets.

- The alternative development sequence available to Hydro requires materially less investment in major bulk power facilities, but without capturing the key underlying aspects of Hydro's recommended power resource plan related to extra-provincial market integration (export and import).

While noting the above fortuitous timing, it is understood that the present review is in fact driven largely by concerns raised consistently by the PUB in a series of prior Board Orders (dating back to at least Order 7/03[20] arising from the 2002 Status Update proceeding), as well as recent controversies surrounding the New York Consultant (NYC) allegations[21]. Specifically, the current hearing is to address:

1) **Long-standing risk concerns and issues of Manitoba PUB raised in previous Orders** – Over the past decade, the Board has continually reiterated its concern that a closer review of Hydro's risks be undertaken including consideration of "potential for inadequate revenue streams for the planned capital expenditures", "lower than forecast export prices and higher interest rates," risks "related to future poorer water flow conditions"[22] and related requirements to import energy or rely on costlier thermal resources in order to meet export contract requirements. Order 32/09 provided specific direction to Manitoba Hydro to prepare an in-depth and independent quantification and study of all of the operational and business risks faces by Hydro, and to file all internally and externally prepared risk reports since 2003/04[23].

2) **Separate Risk Management concerns raised by the New York Consultant (and responded to by Hydro)** - In 2004, Manitoba Hydro engaged a New York consultant to provide consulting services related to risk and over the course of its engagement with Manitoba Hydro

[19] Appendix 6.1 to the GRA.

[20] In directive 6(c) of Order 7/03 Hydro was ordered to produce a "study to quantify specific reserve provisions required to cover the major risks and contingencies faced by Hydro." This recommendation remained unanswered at the 2004 GRA and at the 2008 GRA. Subsequent to the 2008 GRA, the Board in Order 32/09 Hydro further specific directives were provided to Hydro related to assisting the Board with evaluating and understanding the risks faced by Hydro.

[21] The Board notes in order 30/10(page 31) its motivation to conduct "a comprehensive review" as two-fold (1) "recent revelations of the NYC and matters relating thereto"; (2) "a series of prior longstanding Board concerns as outlined in the Board orders and directives wherein the Board, for some time, has identified a need for greater examination of risks faced by the Utility."

[22] Order 90/08 at page 18.

[23] At page 31.

(from 2004 to 2008), the consultant made numerous allegations against Hydro (its officers and directors) relating to mismanagement of various risks and operational errors which have become public and which Hydro disputes[24]. The Board notes the public dispute between Manitoba Hydro and the former Manitoba Hydro consultant (known throughout the proceeding as the New York Consultant or NYC) and related issues regarding risk "are apparently undermining the public's confidence in the Utility," and "the reputation of MH and the confidence of all stakeholders in the Utility is of utmost importance to the Utility and the general public interest". Areas of concern raised by the NYC, disputed by Hydro, and that have been subject to review during this process (either through independent reviews of the NYC complaints undertaken by KPMG at the request of Hydro or independent reviews undertaken by the PUB's own Independent Experts (Drs Kubursi and Magee)) include issues relating to financial reporting; financial forecasting methodologies; long-term contracts and long-term system planning; operations and water management and hydrologic modeling; and power trading issues and governance structure for power trading.

With a mix of ongoing Board concerns, sensational controversies and disparate filings from various parties, a critical evaluation of the regulatory implications of the filed materials requires a consideration of what "risk" means in a rate-setting context, and how it should be reviewed and examined.

Finally, while there are a range of "risk issues" that have been raised by the Board, the NYC and others – there is no "risk management" application or specific risk-related requested approvals being sought by Hydro (outside of those rate-related approvals sought in Hydro's GRA Application) to guide or focus the proceeding[25]. Hydro, as the Applicant in the 2010/11 and 2011/12 GRA, has maintained the position that the focus of risk in relation to the GRA should be on the impact of risk in the test years and that the review of risks should be rooted in the normal rate review process (i.e., an approval of rates as requested is based on the assessment that Manitoba Hydro's risk management practices are appropriate)[26]. Although it is not seeking any specific requested approvals in relation to the NYC allegations, it is in effect

[24] Pursuant to Board Order 95/10 these reports have not been accepted onto the record of the proceeding and are not to be examined as part of the risk management review process. Order 95/10 directed that the NYC's Public Document of June 30, 2010 be Appendix A of the record of the GRA, in place of the NYC's initial reports, filed by Manitoba Hydro November 6, 2009.

[25] While Hydro has not itself internally prepared additional evidence or material to present its views (or its "case") related to the overall risk management review, it has filed on the record various reports (including reviews undertaken by ICF (Appendix 12.2) and KMPG (Appendix H filed pursuant to Board Order 95/10)). However, these are not Hydro's reports, but independent reports provided by separate consultants retained by Hydro and do not effectively provide the case or views of the Corporation regarding its risk management practices.

[26] Hydro has maintained the position that risk is integral to Hydro's entire GRA filing(December 10, 2009 transcript page 16-17) and a review of its rates is a review of its risk management practices (i.e., risk management is essential to ensure there are no unreasonable risks that if actualized could result in undue rate impacts). Hydro's counsel at the December 10, 2009 PHC specifically noted that "Manitoba Hydro expects the Board to review the risks that the Corporation faces as part of its normal rate review process" and "Manitoba Hydro has filed materials regarding risk within its GRA. Virtually all of the materials supporting its Rate Application has a risk component. Risk is an integral part of Manitoba Hydro's business operations and should be examined as such. The focus of the GRA should be on the impact of risk in the test years" (December 10, 2009 transcript page 19).

seeking a public review of its risk management practices (through a review of the KPMG report undertaken as a response to the specific allegations raised by the Whistleblower) in order to restore public confidence in its management and business practices.

3.2 BOARD GUIDANCE AS TO SCOPING OF THIS RISK REVIEW AND HYDRO'S REQUESTED DECISIONS

The Board has specifically noted its intention not to "publish a specific issues list which will limit risk inquiries or bind the Board or any of the participants" (Order 30/10 at page 41); however, Order 30/10 provides the following specific guidance with regard to scoping of the risk management review process:

- **A broad range of rate related risk issues may be considered within the scope of the proceeding** - The Board confirmed its intention to take a broad view of risk cognizant that risk issues must be examined in relation to the Board's rate approval mandate regarding the Hydro 2010/11 and 2011/12 GRA. This provides for a very broad view of risk as the Board continues to cite a mandate to examine whether Hydro's management of all relevant risks is such as to result in undue financial rate implications for current and future Manitoba ratepayers. The Board specifically notes that there are a "multitude of risks faced by MH as part of its business activities and plans….those risk include drought, export markets, interest and exchange rates, labour issues, catastrophic loss of system supply, and changes in accounting standards[27]."

- **Board guidance related to consideration of risk issues in this hearing** - In Order 30/10 the Board specifically noted its preference not to define a scope (or restrict the proceeding to examining any specific question or concern); however, at a broad level, the Board endorsed the scope recommended by MIPUG and Manitoba Hydro (Hydro's own proposed scope agrees with MIPUG's for points 1 through 3) and recommended that the participants keep these questions in mind as points of reference[28]:

    1) Does Hydro have the required capabilities, internal organization, qualified staff, policies and procedures and oversight and governance structures needed to appropriately manage the noted risk; can they be improved, modified or adapted to reduce the risk exposure imposed on ratepayers; [Hydro noted: *Identification and review of the policies and procedures and*

[27] Order 30/10 at page 32; see also Order 17/10.

[28] At page 40 the Board notes the framework provided "is helpful and the Board recommends that all participants keep in mind as points of reference the framework identified by MIPUG with sub-issues regarding categories of risk, as well as the particular questions identified by MH which the Board accepts as addressing the key issues of its risk mandate at a high level".

oversight in governance structures in place to manage identified risks. Are they reasonable in the context of the associated risk?[29]]

2) Is Hydro's approach to risk management appropriate for a Crown owned regulated public utility; [Hydro noted: *Is MH's approach to risk management appropriate in the context of the objects and purposes of The Manitoba Hydro Act?*]

3) Do Hydro's decision making criteria reflect a risk reward tolerance criteria that is acceptable to Hydro's ratepayers and the Board; [Hydro noted: *Does MH's decision making criteria reflect a reasonable risk/reward tolerance taking into account the consideration of the interests of its stakeholders?*]

4) Where risk exposure cannot be modified or addressed through other appropriate risk management practices, what are the financial reserves required to be targeted to address the residual risk items. MIPUG's written submission noted that in this regard, financial reserves to do not serve to reduce the probability of risk event arising or the first-order impact (loss) arising from that risk event. Financial reserves only serve to mitigate potential adverse consequential effects on Hydro's financial position, and more notably in respect of rates, smooth the financial effect on ratepayers over time. Financial reserves cannot be a substitute of high quality and prudent risk management.

- **Matters noted as specifically outside the scope of the proceeding** - It has been clarified that this risk review is not being undertaken to investigate "the NYC's specific complaint made to the Ombudsman or to adjudicate issues between the NYC and Manitoba Hydro," and "is not intended to be the adjudication of a dispute between the NYC and Hydro"[30]. Further, specific allegations of liability by First Nations vis-a-vis alleged property or other damages incurred by any First Nation are also deemed to be out of scope of the review.

As Hydro is the Applicant to the current proceeding (pursuant to its 2010/11 GRA Application), and the separate risk management review is premised on the Board's jurisdiction to review Hydro's 2010/11 and 2011/12 rates, it is concluded that the specific "requested approvals" related to risk of necessity relate to the requested rates and revenues set out in the Application.

[29] MIPUG questions listed at page 23-24 of Order 30/10 and Manitoba Hydro's questions listed at page 25 of Order 30/10.

[30] Order 30/10 "The Board is also mindful that an apparent intention of the NYC to defend its reputation and to substantiate the validity of its conclusions is not the proper basis for intervention. Likewise, the Board is not proceeding with this risk review to adjudicate any disputes between MH, its former consultant, or any other litigation matters between MH and the NYC or any other entity. As a further example, the Board's risk review is not the proper forum for examination of specific allegations of liability by First Nations in SCO vis-a-vis alleged property or other damages incurred by any First Nation" (at page 32).

- Based on Hydro's Requested Approvals as filed, the case advanced by Hydro for approval of the Board is that a 2.9% average rate increase in the test years (premised on a possible future annual rate increase sequence approximating 3.5% through the IFF period) affords the Corporation with sufficient ability to secure the reserves reasonably required to address the potential future risks to the Corporation.

- Pursuant to Tab 12 of the GRA filing, this assessment includes considerations of drought risks (related to low water and consequent financial impacts due to reduced in export revenue and requirements for higher cost thermal generation/ import costs), infrastructure risk (related to the need to invest in significant new facilities or invest in existing infrastructure to avoid impairment or catastrophic failure); export market risk (related to the forecast level of reliance on export sales as a source of revenue) and financial risks such as interest rates, currency risk, and credit risk.

3.3 OVERVIEW OF MATERIALS FILED

In preparation for the risk review, various reports have been filed or commissioned to provide a wide range of perspectives on key risks facing Hydro. Major reports and filings that address risk in a comprehensive manner related to the current proceeding are defined for this evidence as the following:

- **ICF Report:** ICF Consulting (April 2009) in Appendix 12.2 – Hydro engaged ICF to review its risk management practices with respect to export power sales. ICF was not made privy to the NYC reports and did not address allegations raised therein.

- **KPMG Report:** KPMG LLP (April 15, 2010) in Order 95/10 Appendix H – An independent assessment of Hydro's risk management practices and an evaluation of the assertions raised by the NYC[31].

- **PUB Independent Experts:** Drs Kubursi and Magee ("KM Report"; November 15, 2010) - The report prepared by the Independent Experts commissioned by the Public Utilities Board, with a broad terms of reference per Schedule C of PUB Order 30/10.

[31] Terms of Reference provided at Appendix C, Order 30/10, (March 26, 2010) include a review and evaluation of" all relevant available reports and supporting data, systems, models and analyzes which address risk management or contain information affecting risk management for Manitoba Hydro…", including water supply data, management options, risk mitigation, material and business risks. The authors of the KM Report were able to interview the NYC.

In addition, a series of other Manitoba Hydro internally generated reports and topic specific reports have been provided (such as the Risk Advisory report on the 2002-2004 drought[32], and various documents relating to the assignment of the NYC). In addition, Hydro provided a three day workshop for all hearing participants focused on risk issues from May 31, 2010 to June 2, 2010, and the present hearing record includes an unprecedented scale of Information Requests and Appendices.

The materials made available for the risk proceeding are extensive. While no single document can summarize the vast range of observations, it is noted that certain items are directly related to topics that have been identified as being of core concern to ratepayers in recent PUB reviews, including the following:

1) **Drought:** Other than NYC, each of the reports appear to note drought as the first and foremost risk facing Manitoba Hydro, consistent with Hydro's core assertions in each past GRA proceeding. The only apparent exception (NYC) purports to indicate that drought is not as large an issue as the risks Hydro adopts by entering into long-term contracts. While the valuation of the drought risk, and the related confidence intervals, vary somewhat between the different analyses, the confluence of the values reported appear to provide support for Hydro's conclusions. The major reviews also largely indicate support for Hydro's approach for managing drought risk[33].

2) **Long-Term Contracts:** The major reports review the issue of whether entering into long-term export contracts, and in particular under the pricing regimes used by Hydro, is in the best interests of Hydro. All of these reviews appear to agree there is a role for long-term export

[32] Report dated January 2005, filed by Manitoba Hydro February 26, 2010.

[33] For example, the KPMG report indicates "Manitoba Hydro's drought management strategies are prudent in the context of a hydro-based generation system" at page 281; further, "To summarize, on the basis of the policy decisions in place with respect to risk tolerance, Manitoba Hydro quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk" at page xxii. The ICF report provides that "The reasonableness of Manitoba Hydro's quantification of risk exposure related to an extended (5-year) drought" is "reasonable"; that "The Corporation's drought risk mitigation measures are adequate"; that "the Corporation has a reasonable targeted equity cushion"; and that "The 2003 drought resulted in less of a financial impact than the stress test case. This was one of the three worst single years in MH hydrological history. This supports MH's choice of its stress case" (see discussion at pages 25, 26 and 22).

contracts[34] and all except the NYC accept the scale and pricing of long-term contracts entered into by Hydro[35].

3) **Models:** A dominant feature of the major reports is evaluation of the suitability, robustness and accuracy of the various computer models used to operate and plan the bulk power system. Manitoba Hydro has also filed other external reviews completed of the planning models[36]. The reports, with the exception of the NYC, each identify the suitability of the current complement of models, along with a series of lengthy (and at times competing) recommendations for future improvement (effectively each of which is indicated as a potential future incremental benefit and not a criticism of the present model capabilities).

4) **Management Structure:** The various reports each address to varying degrees a massive range of processes for management of risks at Hydro and potential improvements to risk management, including: reporting and governance structures; human resource needs, qualifications and redundancies; the commissioning of new sources of forecasts and data; the structure of internal committees; and, the form of internal reports.

5) **Long-Term Development Plans:** While each of the major reports considers to some degree the evolving structure of Hydro's long-term dependable export contracts and in particular terms related to new term sheets for future supply (notably specific curtailment provisions or options), only the KPMG report assesses the risks inherent in Hydro's recommended Power Resource Plan as compared to what is termed the "No-sale" case. In a detailed assessment in Appendix J, KPMG concludes that, on a pure dollar value basis, Hydro's recommended development plan increases Hydro's exposure to a five-year drought in the early years of the major projects, but that this

[34] The most limited recommendation is in the NYC "Public Document" which states "Till 2017 firm commitments should not exceed 100MW in most months" at issue #29. However, consistent with each of the NYC's "issues" in the public document, there is no analysis or rigour applied to the statement to even test the reasonableness of the remark. In contrast, the KPMG report indicates "Manitoba Hydro has made appropriate strategic choices in entering into long-term fixed price contracts for export power sales" at page 276, and the ICF report indicates "ICF concludes it is appropriate for Manitoba Hydro to enter into long-term firm commitments for 20-30 years in the future in the manner in which the company is proposing – i.e., consistent with its overall plan" at page 6.

[35] The NYC indicated at issue #3 that "The RM assessment did not agree with the pricing methods being utilized by the Front Office to compute prices to customers on a Long-term basis. The pricing methods have not accurately been adjusted for modern market deregulation pricing techniques, and by Hydro continuing to use the same pricing method it used in the eighties without adjusting for deregulation consideration, its stale pricing methods of the past, will very likely incur the same problems in the future of "under-valuing/mis-pricing" its energy". ICF indicated "…the prices proposed for long-term firm contracts appear reasonable and adequate, and MH pricing processes appear adequate" at page 10. KPMG indicates "With respect to long-term contracting for export power sales, it is our opinion that: … Manitoba Hydro has an appropriate methodology for arriving at the sales price in such contracts" at page 276.

[36] Most notably the SPLASH model, for example, in Appendix 74.

increase is well exceeded by the contribution to retained earnings provided by these projects, such that: "...the ability to withstand the financial impact of a five year drought is significantly improved under a Sale Scenario, as there is increased Retained Earnings and improved Debt Ratios in comparison to the No Sale Scenario"[37].

Unique among the reports, the KM Report also sets out recommendations related to considering the potential for requiring materially reduced risk (through various measures, including higher retained earnings) [e.g., options for new domestic electrical rate riders[38]] and new overrides on otherwise modelled targeted amounts of water retained in storage as an added "mitigation strategy"[39] as well as the potential adoption of a new strategy of generation cost minimization rather than net revenue maximization (perhaps limited to short-term sales).[40]

3.4 RISK IN REGULATORY RATEMAKING CONTEXT

The risk review is premised on the mandate afforded the Manitoba PUB by Hydro's 2010/11 and 2011/12 General Rate Application, and the relevant legislative authority, jurisdiction and practice of the Board. In this regard, the context for review of risks inherently relates to their effect on rates and most notably to rates in the time period covered by the present GRA.

3.4.1 Risk as a Regulatory Topic

The regulation of Manitoba Hydro's rates are unique in Canada[41], in a manner that is directly relevant to risk. For jurisdictions that maintain regulatory authority over rates[42], the typical framework is a requirement for the regulator to permit the utility an opportunity to earn a "fair return" in each test year, where the return is measured as a percentage of the assets-in-service financed by equity. In this manner, appropriate rates can (and typically must) be set with reference largely if not entirely to the financial forecasts for the year in question.

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[37] KPMG Report, page J-20.

[38] KM Report, page 245.

[39] KM Report, page 245.

[40] Per KM Report, page 65: In relation to recommendations regarding MOST, "Seventh, we would like to formulate the objective function to minimize cost of generation and delivery rather than maximizing net revenues. The public nature of the utility puts it outside profit maximization strictures. This is not an issue of semantics: the concerns are far deeper. The public utility is a natural monopoly; the last thing the citizen shareholder would like to see is the utility using its market power to maximize its rents, especially given the inherent concern about the implicit trade-off between domestic load and exports."

[41] Previously, other Crown utilities were regulated in a manner similar to Manitoba Hydro, for example Newfoundland and Labrador Hydro, but this form of regulation changed in all examples outside Manitoba (with updates to legislation) to a largely 'rate base/rate of return' form of regulation.

[42] For example, this does not include Ontario or Alberta for rates related to generation, or Saskatchewan or Nunavut where there is no formal regulatory body but simply a consultation committee providing recommendations to the relevant Minister.

In contrast, under the overall regulatory ratemaking context in Manitoba, ratemaking requires consideration of long-term financial targets and projections of 10 to as much as 20 years. While the results in a single individual year can be relevant, by far the more prevalent basis of assessment relates to the long-term. Possibly the best example of this effect is the Board's Order 25/92 which corresponds with the financial impacts of the first in-service of Limestone. In that application, Hydro sought a 3.5% rate increase, which would have yielded a net loss of $17.3 million for 1992/93, but still permit the achievement of an 85:15 debt:equity ratio by the end of the then-relevant IFF horizon (2002). Hydro indicated the proposal was acceptable as the most important financial forecasts were those looking at the longer-term. Instead, notwithstanding the forecast immediate net loss, the Board ordered a 2.65% rate increase (also focused on the long-term requirements for reserves)[43].

The form of regulation in Manitoba also requires regulated ratemaking based on cost-of-service principles[44] as applied by a skilled expert regulator with an open and transparent, procedurally fair review process. This is in contrast to the setting of rates by a market (where market-based measures determine the price each participant is able to charge) or by cabinet (where political and other considerations dominate decision-making). Rates in Manitoba are to be based on costs, including a reasonable provision for establishment of reserves[45].

The cost of service premise for ratemaking provides the framework and rationale for ratepayer investment in the bulk power system, and underlines the risks and rewards accepted and expected by ratepayers based on their historic and ongoing investments in the bulk power system:

- Rates today recognize and reflect the costs required to build and operate the entire electricity system – this includes consideration of "heritage resources" or major generation and transmission

[43] Order 25/92.

[44] As discussed in evidence filed by Messrs Bowman and McLaren in 2006, there is in Manitoba no legislative provision for market pricing to domestic customers or for government ratemaking (outside of clear direction in legislation or regulations, such as in the case of Uniform Rate legislation). COS ratemaking principles have provided the foundation for electricity pricing and policy in Manitoba since the 1970's - As set out in numerous documents from the 1970's through the present, including reports of Manitoba Hydro, the provincial government, the PUB, as well as previous agencies such as the Manitoba Energy Authority.

[45] Regulated utilities use COS to assess and to justify to their customers and regulators that the costs to be recovered from rates charged to different customers classes and for different services are reasonable. MH has been regulated on the basis of its actual costs (IFF) since at least 1986, as well as submitting COS studies for Board review to also ensure rates at the customer class level were designed to reflect underlying costs; in its 1988 report to the Minister the Board stated: "Cost of Service studies are used to determine the fair sharing, between customer classes, of responsibility for the Utility's total revenue requirement. While there are many allocation methods, the central aim is always to allocate costs to customer classes on the basis of known customer characteristics".

assets developed and paid for by Manitoba ratepayers[46] that took on the costs (and accepted the related risks) for these developments[47]. While export sales in many years aid in covering the costs of bulk power assets, Hydro has no ongoing future recourse to the export customers (outside of specific limited contractual provisions) related to any risks of investment in the power facilities that arise.

- In this manner, the bulk power generation and transmission resources currently in place represent the entitlements of Manitoba ratepayers to attractive and stable electricity prices, i.e., the premise for investment by Manitoba ratepayers in these types of assets is the long-term rate advantage and stability afforded by the particular utility investment.

Hydro's system is comprised largely of capital intensive investments (that come onto system in "lumpy" stages, as bulk power investments are typically very large). As is typical with large hydro utility system investments, these assets are long lived (60-100 year asset life) with low long-term operating costs compared to other generation sources. Early in their life, new generating assets can be required to serve domestic load, but they may not yet be fully required for domestic load leading to a need to find ways through exports to maximize revenues from the portion of the generation not yet required to service domestic load. As these assets depreciate over time and become in effect more fully servicing domestic load, and the competing costs of alternative sources of power increase with inflation (or more), the potential benefits or avoided costs of the energy produced materially exceeds the costs to produce that energy. This represents a relatively secure system investment that may have potential initial annual financial losses as the asset comes into service, but provides relatively reliable (although variable) benefits over the medium to very long-term.

Hydro's strategic approach to investment in the system (fundamentally premised upon its ability to export significant amounts of surplus energy, both dependable and opportunity) can serve to enhance, or, if mismanaged, undermine the ability of bulk power assets to contribute to rate stability and predictability for Manitoba ratepayers. Securing long-term export commitments enables development and/or advancement of large northern hydro stations, in excess of what would be required for solely domestic requirements at any given point in time. This allows development of market access (e.g., cross-border transmission investment) and can permit rates to be lower than they would otherwise be on a stand-alone system (were the major hydro development not otherwise possible) and more stable (since

[46] In the case of the HVDC system, there was financing from Government of Canada, provided for the benefit of Manitoba electricity consumers.

[47] Such risks include both one-time investment risks as well as ongoing risks related to water flows, plant performance, etc.

fluctuations and risks related to Manitoba load levels can be offset in part by complementary changes to quantity of power exported, and since the ongoing costs of hydraulic generation are not subject to fuel price fluctuations)[48].

3.4.2 Risk For Hydro Is Fundamentally A Ratepayer Issue

In the context of utility rate regulation as practiced in Manitoba, risk is first and foremost a ratepayer issue and risk tolerances must be aligned primarily with ratepayer values and considerations. This assessment is supported by the following:

- **The consequences of a risk event occurring ultimately fall to the Manitoba ratepayer** - Rates in Manitoba reflect the investment in utility plant and equipment and the attempt to achieve certain financial targets over the long-term. In this manner, risk events occurring in any year serve to alter the level of Retained Earnings and, in effect, become a component of the future rates of the utility (i.e., either through paying rates to rebuild utility reserves, or through paying higher rates where a risk event materializes, including interest on any deferred amounts).

- **Export customers do not bear uncertainties and risks outside of items explicitly included in contracts** – The structure of Hydro's export market does not permit capture of past losses or costs of risk events through above-market pricing in future periods. In any typical competitive market, the corporation (or ultimately its shareholders) are fully exposed to risk events with no recourse to the market. In the case of Manitoba Hydro, this protection for export market purchasers in future (not bearing the costs of past losses) is typical of open market transactions – the situation for domestic customers is not so constrained.

- **Where significant risks materialize, the utility and its shareholder do not directly bear the effects** - This was most recently demonstrated during 2004 GRA proceeding where a severe drought (and consequent reduced power generation and export potential) resulted in losses to

[48] In other hydro jurisdictions different measures are in place to provide for stable and predictable rates, i.e., BC Hydro and Quebec Hydro both define the scale and scope of heritage resources (via government policy) in order to provide a stable and protect assurance of secured quantity of low cost generation. In B.C. this is represented by a "Heritage Energy" amounts of 49,000 GWh which is to be provided to the BC Hydro customers based on the embedded costs of the Heritage Resources as described at page 16 of the BCUC Report and Recommendations in the Matter of British Columbia and Power Authority and An Inquiry into a Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access (October 17, 2003). In Quebec this is represented by an assured supply to domestic customers of 165 TWh at a fixed price of 2.79 cents/kWh from the heritage pool of electricity as set out in section 52.2 of An Act Respecting the Regie de l'Energy.

Manitoba Hydro in excess of $400 million[49] - the highest loss ever experienced by Manitoba Hydro. These losses were recovered in their entirety from ratepayers through a series of rate increases as directed by the PUB in Order 101/04[50] and Order 143/04. The Board in Order 101/04 noted "the drought's impact on the Corporation's retained earnings", and "a related and increased realization [by the PUB] of the financial and operating risks faced by MH[51]", underlined the decision to provide Hydro with a 5% rate increase [effective August 1, 2004 for all customer classes], followed by two conditional rate increases of 2.25% (for each of 2004/05 and 2005/06 upon application of Manitoba Hydro)[52]. There is no prospect in any forecasts reviewed that suggests any recourse to the provincial government debt guarantees for Hydro[53]. There are no Crown utilities in Canada of which Messrs Bowman and McLaren are aware that have resorted in any case to the respective provincial government debt guarantee; examples such as the stranded nuclear facility debt in Ontario were recovered from ratepayers by way of added charges to bills for long periods of time[54].

In this manner, the implications of Hydro's risks ultimately resides with the domestic ratepayer.

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[49] Order 101/04 at page 2.

[50] The Board notes in Order 101/04, "The drought's impact on the Corporation's retained earnings, and a related and increased realization by The Public Utilities Board (the Board) of the financial and operating risks faced by MH, were the primary factors contributing to the Board's decision to grant MH rate increases, as outlined in this Order."

[51] Order 101/04 at page 2.

[52] The Application sought: Approval of electricity rate increases to be effective as of April 1, 2004 and 2005. The proposed rates were projected to result in an annual aggregate revenue increase of approximately $28 million (3.0%) for the fiscal year April 1, 2004 to March 31, 2005, and an additional revenue increase of $24 million or 2.5% for the fiscal year April 1, 2005 to March 31, 2006. MH also sought differentiated rate increases by customer class, and a further upward adjustment of those 2004/05 increases to raise the overall 3% revenue increase requested for the fiscal year over the remainder of the fiscal year compounded average rate increase of 5.5% over two years, represented the minimum rate increases prudence required.

[53] By contrast with the significant ratepayer investments in MH, MH's shareholder absent any investment (or effectively any acceptance of risk) continues to receive significant returns from MH in the form of one-time dividends issued (e.g., $200 million payment in 2003), or in the form of regular annual payments (e.g., debt guarantees, water rentals, land rentals and assessments, corporate capital taxes, sinking fund administration fee, payroll tax, etc). These amounts typically total between 13% to 15% of electric revenue.

[54] See for example discussion in 2006 Cost of Study proceeding (transcript pages 1485 to 1486);

MS. TAMARA MCCAFFREY: And just to go one (1) more step, if I'm a customer in Ontario I'm also paying a debt retirement charge related to nuclear facilities; is that right?

MR. WILLIAM HARPER: Well, it's more than nuclear facilities. At the time that they did the market restructuring they looked at what the -- I think Ontario Hydro's debt ratio was in excess of 100 percent at that point in time. So but they looked at what the -- what they thought was a reasonable commercial financial structure for each of the successor companies, the difference in debt was transferred over to the provincial government and it's held by the Ontario Electricity Finance Corporation. And basically there's a debt retirement charge that goes in everybody's bill basically to retire that debt over time.

MS. TAMARA MCCAFFREY: So everybody pays it?

MR. WILLIAM HARPER: Yes, that's correct.

MS. TAMARA MCCAFFREY: So ultimately then, the Ontario customers bore the risk and responsibility for Ontario Hydro's decisions to construct the facilities, is that right?

MR. WILLIAM HARPER: Yes, you know, you know you could say the Province is ensuring that electricity consumers pay for sort of the electricity costs both past and present.

The KM Report outlines an important relationship in regards to risk tolerance – that is, the risk tolerance of the key principals on whose behalf Hydro operates (in a financial sense) should be aligned with the risk tolerance of Hydro as their agent. The KM Report, however, mischaracterizes the actors in this relationship, at page 6:

> Put differently, the real issue is for the regulators to align the risk exposure and tolerance of MH to match that of the citizens on behalf of whom the government and/or the Public Utility Board typically act. Citizens, in general, are risk averse, and Manitobans are likely no exception. Roughly speaking, this means that they would prefer to take on financial risk only if the probability of gain outweighs the probability of loss. MH tolerance and acceptance of risks may be different from that of the public. The issue is, then, one of a potential lack of alignment between the two and the extent to which regulators are forced to govern the risk tolerance and appetite of MH to match that of the shareholders (the people of Manitoba). This misalignment in risk tolerance arises not only because of different appetites for risk but also from the fact that the *public assumes the costs of any losses either in higher electricity rates (if PUB allows it) or through debt payment charges*, whereas the potential *rewards of the risk-taking are internalized within MH* [emphasis added].

The above KM Report analysis fails to reflect two key factors:

1) The KM Report assumes the public incurs the costs of any losses either in higher electricity rates (if PUB allows it) or through debt payment charges: There is no provision in any regulatory mechanism presently in use in Manitoba for the PUB to not "allow" the public to assume the cost of Hydro's losses. There is only one IFF, which represents a single continuous reporting of Retained Earnings for the purposes of calculating reserve levels and debt:equity targets. To the extent that a risk event arises, the PUB may not allow higher rates to compensation for this item at the time it arises, but ultimately the item will lead to lower Retained Earnings, which in the present form of regulation effectively must be addressed through future rate increases. In this manner, in all cases the ratepayers assumes all costs of Hydro losses, with no recourse to any alternatives.

2) The KM Report assumes rewards of the risk-taking are internalized within Manitoba Hydro: The suggestion that the "potential rewards of risk-taking are internalized within MH" is not true in the financial sense for the same reason as noted above – all "rewards" (ceteris paribus) will in effect

show up in larger net income and ultimately in Retained Earnings[55] (and lower debt borrowings and related interest costs). In time, these higher levels of debt:equity will lead to lower requirements for domestic rates. While there is also potentially non-financial "rewards" that may arise to Manitoba Hydro or its staff from positive returns to risk-taking (e.g., reputation, avoided need for GRA hearings) it is not expected that this was the intent of the citation in the KM Report.

The end result is that while the KM Report properly indicates the need for Hydro's risk tolerance to reflect the risk tolerance of its principals, in respect of financial matters and rates, these principals are first and foremost its domestic ratepayers.

3.4.3 Risk Tolerance / Acceptance by Hydro Ratepayers

Evaluating Hydro's approach to risk (i.e., assessing whether its approach to operating or investing in the system is appropriate or whether the utility is too risky or too risk averse) requires that the risk tolerance of Manitoba ratepayers be considered. This requires the Board to achieve an acute understanding of ratepayer concerns, as well as if and how this may differ from those of the utility, its shareholder, or its other stakeholders.

In summary, the evidence available indicates Manitoba's ratepayer risk tolerance to be borne through rates over the short-term is relatively low. This is consistent with the broad assumptions in the KM Report (page 6, which indicates citizens in general are risk averse). At the same time, as reviewed below, this low risk tolerance to rate instability is not determinative to the decision to pursue long-term opportunities (such as investment in plant), nor even to all short-term opportunities (such as merchant trading). Where these opportunities are sufficiently analyzed and bounded, and provide the means for ratepayers to benefit from the risks that they bear (such as through lower or more stable rates in future) they have been viewed as a suitable addition to the assets and activities underlying regulated rates.

Ratepayer values and concerns in Manitoba can be inferred from the past history with respect to regulatory reviews, from fundamental principles of rate regulation as espoused in authorities such as Bonbright's Principles of Rate Regulation, from practice in similar jurisdictions, or as reflected in Manitoba Hydro's own Rate Objectives (see Tab 10.1 of the Application). In this regard, the following are noted:

[55] The only possible exception in past practice is the one-time dividend collected by the provincial government in 2003 on the basis of good export revenues, where all downside risks of the exports were in effect carried by ratepayers and ultimately addressed through higher rates to re-establish reserves once the drought effects were experienced.

- **Stability and predictability of rates for consumers and the utility is a high priority**[56] – ratepayers value a minimum of unexpected changes and a sense of historical continuity in rates. While until recently Manitoba rates have been relatively stable and predictable, the trend in recent years has been towards relatively greater levels of instability. Examples of recent instability include the following:
  - With no increases from 1997 to 2004, in the GRA filings in 2004 and 2008 Hydro was ordered increases well above the rates applied for in the Application and above the levels of general inflation, with many intervening years experiencing no rate changes.
  - Hydro determining in 2006 that it would not seek the conditional rate increase of 2.25% (due to good water conditions at that point in time), an increase that had already been provided for in Order 101/04 and then later in February, 2007 re-applying for that increase (in advance of a 2008 GRA filing for an additional 2.9% increase).

As evidenced in other jurisdictions unstable and unpredictable rates can become a key issue of concern facing ratepayers, regulators and policymakers. For instance, while in the mid-1990's Yukon had lower residential rates than several other North American jurisdictions, an intense concern existed for ratepayers and policy makers related to the acute instability in Yukon rates compared to these other jurisdictions, with instability attributed to "fluctuating local market conditions" including shutdowns of the Faro mine in 1993 and 1997, swings in diesel fuel prices, and water availability for hydro-generation facilities[57]. While the Faro mine shut down permanently in 1998 (making permanent the adverse impacts on rates driven by that one factor[58]), Yukon has continued to ensure mechanisms in place to ensure rate stability for ratepayers including the Diesel Contingency Fund to address occurrences of low water (drought) and a Deferred Fuel Price Variance Account (to smooth impacts of diesel fuel price changes throughout the year an between test years).

While Manitoba Hydro does not presently implement any similar rate stability mechanisms, it recognizes this core principle of rate stability in its proposed GRA rates noting they meet the objective of gradualism and sensitivity to customer impacts. Within a current context that targets

[56] Combines concepts such as revenue stability, rate stability and effectiveness in yielding total revenue requirements under fair return standard.

[57] See, Cabinet Commission on Energy: Discussion Paper (pages 6-7); which notes, "even in places where higher electricity prices exist, there appears to be little public debate over prices, perhaps because of greater price certainty in those jurisdictions." Subsidy programs were developed based "on a limited view of affordability" and greater attention to price stability (which arguably "is a key component of affordability for the majority of customers in all classes").

[58] Rate instability in the Yukon during the mid-1990's was due primarily to rate increases triggered by the 1993 and 1997 shutdowns of the Faro mine (which accounted for 40% of the load on the system when operating).

relatively gradual overall rate changes within an IFF horizon, the current rate design criteria applied provides for annual adjustments to revenues by customer class within a narrow band of the average proposed increase in domestic rates for each year. Hydro's further specific guidelines provide for the following combined impact of proposed class average rate increases and adjustments to rate structure[59]:

- For Residential customers, no customer will experience a bill increase which exceeds the greater of $3.00 per month or three percentage points more than the class average increase.
- For General Service customer, no customer will experience an increase in their average monthly bill over a year which exceeds the greater of $5.00 per month or five percentage points more than the class average increase.

- **Recognize Cost of Service reflective of existing facilities**[60] - To ensure fairness and stability in rates, customer rate levels should match the current cost of providing power, including provision for the existing fixed costs of the utilities. Manitoba Hydro's long-term target is to have all class Revenue Cost Coverage (RCC) ratios in the range of 95% to 105% (similar to most regulated utilities in Canada, with costs measured on a standard embedded cost basis), and further that all classes should be gradually moved toward RCC's of unity[61]. Prior to achievement of this target zone for each class, rate instability can be increased by the need to complete interclass rebalancing of rates, as well as to reflect overall cost changes.

- **Pursuit of suitable long-term opportunities** – Regulatory review of Hydro's hydraulic development opportunities in 1990 (Conawapa and Bipole III) and 2004 (Wuskwatim) in each case recommended pursuit of the development and associated transmission, despite the inherent requirement to generate substantial portions of the plant-related revenue from export markets. In each case the plants were premised on lower long-term rate levels than would be required absent the plants.

    - In the case of Conawapa, a large plant (cited at 1290 MW), the accepted development sequence required coupling of the commitment to construct the plant with entering into a long-term (22 year) system participation contract (1000 MW) with a secure export

[59] See 2010/11 GRA, Tab 10 at page 3.

[60] May include concepts such as fairness of specific rates in the apportionment of total costs, and avoidance of undue discrimination in rate relationships.

[61] See page 10 and page 2, MH notes attainment of this objective will take longer than anticipated given the proposed across-the-board increases. Further, Manitoba Hydro intends on having an external review done of the Cost of Service Study methodologies before relying on the results of the study for rate design.

customer (Ontario) as well as diversity agreements and DSM to complement the development. This matching of long-term contracts with long-term construction commitments reflects the degree of risk tolerance of domestic ratepayers. Absent this proposed development sequence, the alternative reviewed at that time by Hydro's Chairman[62] was the need to commit to a new generation sequence of Conawapa or Wuskwatim for in-service by 1999 (as well as related risks of potential thermal life extension) "...with all the costs and risks to be borne by Manitoba consumers unless export sales could be negotiated".

- With respect to Wuskwatim, the project was proposed as an advancement of the in-service date from the date assumed to be required for service to domestic ratepayers, to an earlier in-service date (2010) with associated power surpluses being market extra-provincially. The project advancement scenario was anticipated to have a 2 percentage point adverse impact on debt:equity ratios and cause a 2 year delay in achievement of the target (75:25) debt:equity ratio[63]. In the case of this smaller project (200 MW) there was no identified need for a committed export contract prior to project commitment, but instead confirmation that transmission capacity existed to market the power as needed, and review of a range of reasonable export market price scenarios. The project advancement proposal remained economic under the different scenarios.

In short, where long-term commitments and their attendant risks can be shown to be ultimately less-risky over the long-term than delay, and bring added benefits in terms of development and system flexibility, ratepayers have indicated a willingness to accept the costs and risks of the major capital plans of Hydro.

- **Acceptance of short-term trading benefits** – In each of the 2006 Cost of Service review and the 2008 GRA as well as in the presentations provided by Hydro on June 1, 2010[64], Hydro set out the basis and rationale for engaging in "merchant transactions" that are not core to providing power supply to Manitoba. This limited activity (total revenue of $44.4 million, costs of $32.4 million from 2005 to 2009) carries specific risks that are in addition to the risks that arise from core Manitoba Hydro activities. The activities has to date been accepted by ratepayers and the PUB.

[62] 1990 PUB Review of Major Capital Project, as summarized in the PUB's November, 1990 Report to the Minister, pages 3-5 to 3-6.
[63] Clean Environment Commission Report on the Wuskwatim Generation and Transmission Projects, September 2004, page 52.
[64] Presentation of A. David Cormie on "Manitoba Hydro's Export Markets" slides 26 and 27.

3.5 SPECIFIC RISK TOPICS RELEVANT TO THE BOARD'S REVIEW OF HYDRO RATES

While the reports and filings made available in this proceeding cover a massive range of issues and aspects of risk, the items in many cases go beyond the topics that are suitably able to be addressed in a regulatory context. This situation is particularly shaped by the framework in Manitoba, given the Board's limited jurisdiction with respect to rates (as compared to, for example, regulation of a utility's major capital investment as is commonly found in other jurisdictions).

In considering the relevance of risk items as they relate to rates, reviews in this proceeding need to reflect specific core principles of regulation. The submissions of Manitoba Hydro in this regard have at times suggested Hydro sees the Board role in respect of risk as reviewing, in essence, a lengthy shopping list of items that the Board can and ought equally assess (see example below from December 10 prehearing conference transcript, page 16-17, Ms. Ramage):

> When Manitoba Hydro presents a General Rate Application, it fully expects the Public Utilities boards to review the risks the Corporation faces as an integral part of its normal rate review process.
>
> Typical questions we would expect the regulator to ask include: What are the risks that might prevent Hydro from achieving the objectives as set out in its strategic plans and its financial forecasts? Are the proposed rate increases adequate -- adequate to meet Hydro's stated objectives? What happens if a drought - one of Hydro's major risks - occurs next year? What are the potential impacts of a drought on the test years? What are the impacts of prolonged economic downturn? What happens if natural gas prices stay at current depressed levels? What happens if there's a spike in interest rates? How well-prepared are we for catastrophic loss of system supply? How would we respond to a shortage of skilled labour? What impacts will commodity prices have on costs? What are the consequences of a loss of export markets? And what happens -- what's going to happen with IFRS?
>
> These, and a multitude of other risks, are faced by Hydro as part of its everyday business. The PUB must satisfy itself that these risks are being appropriately managed as part of its rate approval mandate.

In contrast to Hydro's apparent characterizations, the risk items set out by Hydro (and the multitude of other risks highlighted in the various documents) tend to fall into three general categories that have very different implications with respect to regulation:

1) **Management Risks:** It is not the regulator's role to manage the utility. Decisions regarding intricate details of corporate organization, governance, staffing, and implementation of computer system improvements can and must be left to utility management. In this proceeding the Board should consider the plans and approach adopted by Hydro to assess and, where appropriate, respond to the various management-related comments received in the risk reports, but the actual details of implementation go well beyond rates and are at best tangential to determining the appropriate rate levels. While the Board may have insights and commentary on these items to help Hydro shape its response, ultimately the specific skills and expertise of the utility must be relied upon to manage its responsibilities. Examples include:

    a) Training of staff and establishing human resource redundancy;
    b) The structure of Hydro's committees for review of systems status and trading positions;
    c) Most details in respect of computer models, technical details, hardware;
    d) Approaches adopted to manage debt interest rates, and set targets for long-term versus short-term debt; and
    e) The implementation of methods to manage currency exchange rate variability.

2) **Normal Regulated Utility Risks:** A wide range of risks noted in the reports are typical and well-understood regulated utility risks that are appropriately addressed by the regulatory framework in Manitoba. 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. To use an example, while capital project cost escalation risk is identified, there is no practical opportunity today to forward purchase, for example, rebar for the eventual construction of Conawapa – this is simply an item that will one way or another form a component of Hydro's future costs. In the review of these risks, the regulator's role must effectively focus on rate impacts and ensure appropriate rate adjustments (and only appropriate rate adjustments) are made to address the realities faced by the utility. Examples of such items include:

    a) Risks related to inflation and general economic activity;
    b) Load forecast variability, and consequent costs of bringing on-line new higher-cost resources to supply the overall level of load;

c) Trends in labour costs, skilled worker availability; and

d) Justifiable market-based capital project cost escalation.

- **Exceptional Risks Borne by Ratepayers:** In the setting Manitoba Hydro's rates, it is clear there remains one interrelated set of risks that is acute and bears directly on ratepayers. The concept is perhaps best captured by the reference in the GRA filing Tab 2 Table 2.1.1 (and expanded in PUB/MH I-1 (Revised)) as *"Extra Provincial Revenue (net of fuel, power purchased and water rentals)"*[65] (herein referred to "Net Extra-provincial Revenues" or "NER") comprising all risks related to drought, export prices and market access, and fuel prices and volumes. The concept as set out by Hydro excludes the typically stable items in Hydro's IFF, comprising General Consumers Revenue, "Other" Revenue, Operating Maintenance and Administration expenses ("OM&A"), Finance Expense, Depreciation and Amortization, Capital and Other Taxes, and Corporate Allocation. While each of the items contained in the NER reflects an degree of inter-year (and intra-year) instability compared to all other items in Hydro's IFF, there are aspects of the NER items that are at least partially internally offsetting and compensating – for example, low flows will typically lead to lower export revenues, but also lower water rentals; high opportunity prices in export markets may lead to higher export revenues combined with higher purchased power expenses (or potentially even fuel expenses) for certain types of export transactions, etc. As noted in previous sections of this submission, Hydro's domestic ratepayers effectively ultimately bear the risks associated with this complement of revenues and costs.

Appropriately addressing the rate effects arising from these exceptional risks goes to the core of the Board's role in establishing Manitoba Hydro's rates. Mechanisms to address this issue need to reflect to some degree the following objectives:

- **Maximize Net Revenue Benefits:** Hydro's management of its system should target maximum reasonable benefit from the NER over the long-term consistent with ratepayer risk tolerance. At the same time, and to the degree possible, stability in NER values over time is also a desirable objective. While the success at achieving this balanced objective can be monitored and guided by the Board, it is ultimately up to Hydro to implement and manage all material aspects of its underlying system.

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[65] MIPUG has previously set out (e.g., in Exhibit MIPUG-14 from the 2008 GRA) that the concept is useful and valid – but the terminology is probably poor. Although Hydro calls this line "Extraprovincial Revenues (net of fuel, purchased power and water rentals)" it is in fact not solely linked to extraprovincial revenues as it includes items such as water rentals on power used for domestic consumption. The value is more properly understood as the sum total of all items materially affected by water flow and export market variations.

- **Establish Reasonable Reserves to Maximize Rate Stability:** To ensure rate stability and predictability can be maintained over the long-term, the inherent variability in the NER values should be addressed by long-term financial reserves. From this perspective, reserves are a regulatory concept that must be driven by the PUB.

- **Ensure Reserves are Transparent and Secure:** Reserves must be managed to provide transparency and security for amounts set aside out of rates for the purposes intended. The long-term benefits that arise from the presence of reserves (such as effects on borrowing requirements and costs) accrue to ratepayers.

3.6 CONCLUDING COMMENTS AND OBSERVATIONS

Based on review of the major risk reports filed, the following concluding comments and observations are provided, organized to reflect the Board's "points of reference" as accepted in Order 30/10.

At the outset, it should be noted that none of the major reports concluded any merit to the sensational claims of mismanagement, blackouts and unnecessary billion dollar losses contained in the NYC allegations.

Question #1 - Does Hydro have the required capabilities, internal organization, qualified staff, policies and procedures and oversight and governance structures needed to appropriately manage the noted risk; can they be improved, modified or adapted to reduce the risk exposure imposed on ratepayers?

For all intents and purposes, it appears all of the major reports conclude that Hydro's systems and approaches for managing risk, particularly risks related to bulk power and marketing are reasonable. Each notes that there are means to improve or strengthen risk management practices via changes that are appropriately in the realm of Hydro's management team and not the regulatory forum.

Question #2 - Is Hydro's approach to risk management appropriate for a Crown-owned regulated public utility? and Question #3 - Do Hydro's decision making criteria reflect a risk reward tolerance criteria that is acceptable to Hydro's ratepayers and the Board?

In light of the focus adopted in the major reports, an additional relevant consideration related to these items is whether Hydro's risk management approach and decision making criteria are appropriate for a dominantly hydro-based utility, including Hydro's past integration with extra-provincial markets and its recommended development plan which materially increases this integration.

Each of the major reports concludes Hydro's participation in export markets is appropriate, and further that the approach adopted by Hydro to date (particularly the marketing of dependable energy under long-term contracts to the extent possible) is reasonable and indeed necessary to maximize the benefits and minimize the risks associated with major capital investment in bulk power assets.

To the extent addressed in the major reports, a strong preference is noted for the direction and logic underlying Hydro's recommended development plan, as opposed to a more limited domestically-focused alternative (with no new cross-border transmission, no new system participation power contracts with WPS or MP, and no advancement of the Keeyask plant). KPMG in particular concludes that the fundamentals of Hydro's recommended development plan increase Hydro's ability to handle risk, under any forecast export prices scenario (low, expected or high). The ICF conclusions appear to be best summarized in the KM report noting 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"[66]. A much more limited set of conclusions regarding the concepts underlying Hydro's recommended development plan are provided in the KM report, focused on the fact that the present development concept has extra-provincial export market participants funding in part the costs of new cross-border transmission as part of new system participation contracts: "Higher fixed prices could perhaps be extracted but perhaps at the expense of the large transmission investments to be made by the counterparty. These investments are crucial for MH to remain in the firm as reliable status in MISO. In their absence firm prices of MH could easily turn into lower non-firm prices"[67].

These conclusions accord well with the understood risk tolerance of Manitoba ratepayers, consistent with matching long-term dependable power with long-term committed costs (such as interest rates) and revenues (such as locked in contracts).

As specific variants on this theme:

1) **Merchant Trading:** ICF concluded Hydro is appropriately pursuing arbitrage merchant trading, but should not be involved in non-arbitrage merchant trading "in part because public entities usually do not pursue such high risk transactions, and they create potential for rate shocks"[68]. This conclusion is consistent with the understood risk profile of domestic ratepayers.

[66] KM Report, page 200.
[67] KM Report, page 209.
[68] At page 25.

2) **Short-term Contracts for Dependable Power:** As to contracts for future facilities, KPMG concluded that the use of shorter term contracts would significantly increase costs and risks to Manitoba Hydro "if it were to commit to multi-billion dollar investments with contractual sale commitments for shorter durations (e.g., two years) potentially rendering projects infeasible". With regard to long-term contracts – Chapter 4 of the KPMG report concludes that "long-term contracts mitigate Manitoba Hydro's market risk through diversification of its export sales mix, and mitigate its drought risk because of both the returns generated by the contracts and the creation of the transmission capability[69]."

3) **Generation Cost Minimization:** The KM Report provides reference to a need to change Hydro's objective function in respect of the MOST model (short term scheduling) from one of "maximizing net revenues" to instead "minimize cost of generation and delivery"[70]. This recommendation is not cited in the KM Report in respect of any other aspect of Hydro's operation or planning outside of the MOST model, where it is noted at page 65:

> Seventh, we would like to formulate the objective function to minimize cost of generation and delivery rather than maximizing net revenues. The public nature of the utility puts it outside profit maximization strictures. This is not an issue of semantics: the concerns are far deeper. The public utility is a natural monopoly; the last thing the citizen shareholder would like to see is the utility using its market power to maximize its rents, especially given the inherent concern about the implicit trade off between domestic load and exports.

The recommendation at its core appears premised on consistency with the long-term well-accepted overall regulatory intent in Manitoba to minimize net costs of generation and delivery to domestic customers. Given the comment is in relation to a short-term model, a time horizon in which rates to domestic ratepayers are effectively fixed, maximizing net revenues from the system from moment-to-moment (i.e., through export market participation, as Hydro's model now targets) is entirely consistent with minimizing net costs to domestic customers. In the long-run, when domestic rates can be changed, the KM Report comment simply reflects the ongoing relevance of PUB regulation – to ensure domestic rates are not a component of "profit maximization" at the expense of committed captive domestic customers. The specific KM recommendation, therefore, does not appear to be appropriate in this case.

[69] At page xxii.

[70] KM Report, page 65.

Question #4 - Where risk exposure cannot be modified or addressed through other appropriate risk management practices, what are the financial reserves required to be targeted to address the residual risk items.

The approach adopted by the major reports to financial reserves reflects three fundamental aspects: quantification of risk exposure, levels of reserves that need to be targeted to address this risk exposure, and the form of reserves.

1) **Quantification of Risk Exposure:** Each of the major reports focuses on drought as the main risk to be quantified. In short, the reviews appear to take no issue with Hydro's approach to quantifying its main risks related fundamentally to drought:

   a) **ICF** considered the Manitoba Hydro estimated cost of a five year drought from 2010/11 to 2014/15 resulting in a $2.7 billion reduction in retained earnings. ICF noted: "Our assessment of Manitoba Hydro's quantification of risk focuses on two main issues. First, we assess whether the five year drought scenario is reasonably stressful to account for the financial impacts of an extended drought. Second, we assess whether the quantitative simulation of the scenario is reasonable". ICF indicates it "considers Manitoba Hydro's quantification of risk exposure to drought to be reasonable" and that ICF examination of a five year drought is sufficient such that "Manitoba Hydro does not need to simultaneously examine multiple risk events"[71].

   b) **KPMG** reviews Hydro estimate of a 5 year drought starting in 2009, as provided to the PUB in response to Order 117/06, at a $2.8 billion reduction in retained earnings[72]. They conclude that "...on the basis of the policy decisions in place with respect to risk tolerance, Manitoba Hydro quantifies its drought risk appropriately..."[73]

   c) **The KM Report** summarizes its conclusions that "The costs of a 5 year drought are in the order of magnitude used by MH than the Consultant and the inclusion of other risk factors increases measurably the drought costs"[74]. While they do not quantify the costs of a multi-year drought, the authors conclude that the cost of the worst one year drought (1940) results in mean reduction in net income of $788 million[75] (and droughts worse than this level do not increase the adverse effect, due to contractual curtailment rights). While other downside assumption scenarios can increase this value, the $788 million is

[71] ICF Report, pages 108-109.
[72] KPMG Report, pg 173.
[73] KPMG Report, pg xxii.
[74] KM Report, page 191; see also page xxxii.
[75] At page 243.

intended as mean value comprising all potential scenarios on the other critical variables. This value is extremely close to the Manitoba Hydro calculation of the costs of a one-year drought corresponding to the flows from 1940 (were they to reoccur in 2011/12) of $747 million[76].

2) **Level of Financial Reserves:** The practice to date in considering Hydro's required level of reserves or retained earnings is generally to target the quantum of reserves to equal the cost of a benchmark drought. While this drought was for many years a two year drought (all GRA reviews prior to 1997), the more recent evidence tends to reflect a five year drought as a concept for benchmark. In this regard, ICF and KPMG continue with this basic core logic, and their respective reports indicate that Hydro's target for reserves, aligned with the cost of five year drought, are within a reasonable range. In particular, ICF notes: "To minimize the impact of a severe drought on its financial stability and rates, Manitoba Hydro should maintain at least the cost of an extended five year drought in retained earnings — this is consistent with the Corporation's goal"[77] while KPMG indicates: "MH quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk"[78].

In contrast, the KM Report suggests what appears to be a materially higher level of required reserves. The precise value of the proposed target is not calculated in the KM Report, nor is it set out in any manner that accords with the broad themes of the remainder of the KM Report regarding requirements to utilize quantified probability-based criteria and thresholds. The core aspect of the KM Report on this item discusses various mechanisms that can help mitigate financial risk, such as use of derivatives, and then concludes:

> "The weights to put on these different items can crucially alter the final outcome, but a target of equity of at least a high percentage of the full cost of a seven year severe drought with high import prices, high interest rates, and an appreciated Canadian dollar must guide the selection of these weights. We argue strongly in favour of avoiding targeting massive borrowing, the debt structure of MH is already high and moral hazard behaviour must be avoided."[79]

[76] PUB/MH I-81(a).

[77] ICF Report, page 126.

[78] KPMG Report, page xxii

[79] KM Report, page 18-19.

There are two fundamental issues with the KM Report's approach in this regard:

- First, in regards to the **"target of equity"**, while no estimate is provided by the KM Report, as noted above where the report does calculate drought costs, it does not indicate any materially different costs estimates for droughts than Manitoba Hydro's calculations (e.g., for the one-year 1940 flow scenario). The KM Report further suggests that the cost of a drought combined with high import prices can be in excess of 50% higher than the costs for a drought alone[80]; it is not clear how much further (if at all) cost escalation might arise from combining in the additional constraints of high interest rates and an appreciated Canadian dollar. As an approximate quantification, Hydro's evidence is that the cost of a seven year drought is approximately 30% higher than a five year drought - by a rough measure then, the level of target reserves per the KM Report approach may approximately double the targets used by Hydro, ICF and KPMG[81] (in the range of an approximately 50:50 debt:equity ratio, a target level of over $5 billion).

- Second, in regard to **"avoiding targeting massive borrowing"** (in order to avoid "moral hazard behaviour"), no further detail on this item is provided in the KM Report. Further, the potential ramifications of this approach for Hydro's fundamental premise for development of capital intensive long-lived resources as a public power initiative are not clear. In particular, the reference does not indicate if the avoidance of massive borrowing is only to apply to risk events and borrowings to "fund" potential net losses, or if it also extends to borrowings for the purpose of financing new assets. Absent "massive" new borrowings, there is no credible alternative for development of new plants such as Conawapa as public power resources – alternatives that would have to be considered in light of an inability of Manitoba Hydro to borrow in this manner would presumably include private sector development of the plant with some form of purchase agreement with Hydro (i.e., an Independent Power Producer ("IPP")), the development of new "equity" in Hydro from some form of partial or full privatization, or the abandonment of new capital-intensive hydraulic generation development in Manitoba in favour of lower capital cost sources such as natural gas turbines. It is not apparent that any of these forms of options accord with the established public policy framework in Manitoba or with long-term ratepayer benefits.

The combined effect of the KM Report recommendations, in the event they are meant to be applied in this manner, is to impose on Hydro a framework more appropriately focused on a private sector utility,

[80] Per the KM Report page 229, the cost of a one year drought is estimated at $788 million, while the cost of a combined one year drought with high import prices is estimated at $1.2 billion.

[81] The Hydro estimated impact of a 7 year drought on retained earnings in 2009 is $3.5 billion (per KPMG page 173 – approximately 30% higher than the cost of a 5 year drought) plus an estimated minimum 50% premium for the other confluence of risks noted by KM would yield a target retained earnings level today of $5.2 billion.

where there is a need to be attentive to the invested equity of shareholders and related annual returns[82] and to ensure that the utility's lenders are secure solely with the protection of the underlying assets, specifically: "The organization's equity can be thought of as a "cushion" against potential losses. This cushion protects the organization's shareholders or other lenders"[83].

It is difficult to accord this excerpt with the core structure of Manitoba Hydro adopted in the interests of the Province and of ratepayers, as a public power enterprise, oriented toward orderly development of the Provinces natural waterpower resources, providing power-at-cost, with a very long-term perspective and horizon for benefits, and with the benefit of the Government of Manitoba backstop on borrowings to permit this patient long-term commitment to unfold.

The various discussions of reserves, either ICF/KPMG or the KM Report, focus, in effect, on reserve levels needed to ensure corporate continuity and protection of the lenders. None of the reports contribute to advancing the state-of-the-art in respect of calculating optimum reserve levels to reflect core ratepayer values and interests. Applying the philosophies and mathematics of the KM Report, for example, it would appear possible to define a criteria for reserve levels based on a target reasonable (but not excessive) level of rate stability through a drought event (including the period prior to, during the course of, and in the years following while reserves are being rebuilt to prepare for the next drought) with a high degree of statistical confidence[84].

3) **Form of Financial Reserves:** Although each of the major reports goes to considerable lengths to assess and quantify Hydro's required reserve provisions, only the KM Report appears to contain any comments regarding the appropriate form of any such reserves (financial or otherwise). This item requires careful consideration by the PUB, separate and apart from any conclusions arising from expertise in risk management. The KM Report in particular notes a number of key aspects to the form of reserves that may be considered (at page 245), each apparently as complements or offsetting mitigative measures to the need to maintain very high levels of retained earnings (as noted above):

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[82] For example, to ensure a continued ability to protect stock prices, pay dividends, or raise additional future share capital from capital markets.

[83] KM Report, page 46.

[84] This reserve level may be calculated to be a relatively higher value under the current system, where interest costs are a compounding effect of a drought event, and lower were this compounding effect to be isolated. That is, in response to a major drought and related reduction in reserve levels, ratepayers will face immediate and material upward rate pressures to quickly rebuild reserves, compounded with added annual costs for financing charges due to higher debt levels. This latter factor alone, in the case of a benchmark $2.6 billion drought, can total a 10% upward rate pressure before any added reserve rebuilding occurs. In this ratepayer context, typical investor risk concepts, focused on whether an organization can survive a risk event and fulfill its financial obligations, can potentially fail to consider the effects beyond the risk event horizon.

- Physical "water in storage" reserves, in excess of amounts otherwise calculated to be optimally left in storage at any given point in time, as complement to retained earnings.
- A "specially created fund" as an emergency provision to be used in the event of a drastic drought (where "drastic" is not defined in any relation to the experienced droughts or dependable energy criterion).
- The source of funds for the above noted emergency provision derived from "an additional rider on domestic rates".

At its core, the KM Report appears to accept the premise that the dominant form of risk-related reserves for Manitoba Hydro reside in the form of retained earnings. In regard to the complementary reserve-related items, the KM Report's recommendations appear to reflect a misunderstanding of the regulatory framework in Manitoba, or run counter to other ratepayer priorities:

- The ***water in storage*** concept appears premised on an idea that while the long-term system "net revenue maximization" analyses completed by Hydro are appropriate (using the various models and marketing frameworks in place), in any interim period where the overall level of Retained Earnings are below the target level, Hydro should consider narrowing its risk tolerance through being more conservative in regards to use of water (defined as a "mitigation strategy"). A corollary to the inherent trade-offs of this approach is that, during the period this strategy is in place, the system will therefore not be maximized for net revenue generation, foregoing the opportunity to maximize long-term financial returns. In this manner, it is not apparent that the needed reserves can be secured without materially higher rate levels during this period to both (a) compensate for the lost average net system benefit from the inferior water management approach, and (b) more expeditiously build toward the apparently targeted 50:50 debt:equity level. Overall, the choice would appear to be between this recommended KM strategy and an alternative that establishes somewhat more moderated rate levels, but with use of any added revenues (along with the added average net returns from retaining an optimized water management strategy) to more expeditiously drive toward the high target equity level. In short, this recommendation appears at best to undermine the central effect of the KM equity recommendation; that is, to build towards a high target equity level expeditiously.

- The ***specially created fund*** concept is far from a new concept before the Board. The MIPUG evidence from the 2008 GRA reviews the history of this topic dating back to at least the Board's

Order in the 2002 Status Update proceeding[85]. A distinction in the KM report approach to the fund and the earlier MIPUG evidence is that the KM Report appears to limit the scope of the fund to deal with "emergencies" (undefined) related to a "drastic drought" (undefined). For other relevant regulatory reasons, the MIPUG concept extends the potential role of such a targeted reserve provision to also serve as (a) a useful regulatory control on Hydro in relation to controllable costs (as compared to variable and uncontrollable precipitation and export market conditions) and (b) a means to clarify the purpose of the funds as necessary and required reserves, such that they are not undermined by, for example, any potential future payments to the shareholder that would be inconsistent with the fundamental basis for establishing such reserves[86].

- The concept of ***an additional rider on domestic rates*** is an understandable reaction from GRA participants not engaged in recent Hydro rate proceedings. The more appropriate source of potential revenues for any funding of extra reserve provisions (either per the KM Report limited to emergencies, or a broader reserve concept per earlier PUB proceeding discussions) is through the priority allocation of all "above cost" export revenues. As set out in Hydro's cost-of-service study, under a principled allocation of system costs to each class of customers, export sales presently yield revenues in excess of the average costs to serve the sales. Under the current system, these amounts are credited back to certain customer groups in the form of lower rates in the year the export revenues are earned, where these credits do not derive in any manner from the service to the individual domestic customer's loads (including, for example, amounts being credited towards the low voltage distribution assets, which bear no relation to serving exports).

[85] Board Order 7/03 indicated "The Board believes that Hydro should develop a policy to identify a reserve provision amount and, in particular, to set the circumstances under which it can be drawn down or increased, keeping in mind the statutory limitations in the *Manitoba Hydro Act*." Hydro's response to this directive was filed in the 2004 GRA, Appendix 11.1, which is a general Corporate Risk Management plan, with no discussion whatsoever about reserve provisions, or circumstances for increasing or drawing down such a provision. Board Order 101/04 then directed Hydro to conduct a "study on the implications of internally restricting retained earnings as a form of self-insurance reserve and rate stabilization fund, to restrict any future dividend payment until the 75:25 debt:equity ratio has been achieved and/or exceeded." Manitoba Hydro's four paragraph response notes: "Manitoba Hydro believes the establishment of an internally restricted retained earnings account would serve no particular purpose." Hydro further noted in response to Coalition/MH-I-106(a) in this proceeding when asked about the pros and cons of a rate stabilization fund "There are no pros of establishing and maintaining a separate rate stabilization fund/drought protection fund for domestic customers."

[86] For example, the 2003 dividend payment of $200 million.

- There would not appear to be a reasonable basis to implement new riders to customers prior to a priority reallocation of the export revenue residuals[87] to this purpose, in the interests of long-term stability of rates.

3.7 PROCESS TO MOVE FORWARD

The materials provided in this proceeding permit a major step forward in the process of regulating Hydro. The risk materials are comprehensive and appear to address all major objectives for the review in regards to the identification, quantification, and internal process for managing, all of Hydro's major risks.

The materials provided to date, however, do not advance the discussion in regard to the form of reserves. This topic received considerably attention in the 2008 GRA, at a conceptual level. No specific ready-to-implement proposals have been advanced or assessed. As noted by the Board in Order 116/08, in regards to proposals regarding alternative forms of reserves (Rate Stabilization Reserve or "RSR") for Hydro:

> However, if the Board were to adopt such an approach, a process would need to be developed to determine an appropriate level of the RSR. What would represent an adequate RSR? Previously, the Board has requested that MH file a quantified analysis of its major risks and analysis that would put numbers to the major risks that have been identified. Not only would the risks associated with a five-year drought be quantified (MH has suggested that such a drought could result in losses of over $3 billion), but also the risks associated with the failure of major infrastructure, interest rate increases, further currency changes and, for any reason, the loss, even if temporary and for whatever reason, of the export market. In the absence of much more rigorous analysis, the Board is uncertain whether such an analysis would arrive at a RSR lower or higher than the current level of retained earnings required under a 75: 25 debt to equity target. The Board is concerned that there may be a case for establishing a higher reserve requirement, one that would further push rates. On balance, the Board is of the view that a regulated RSR, i.e. the adoption of MIPUG's specific reserve proposal, is currently premature, at least ahead of MH identifying and properly quantifying its risks, as has

[87] Hydro has previously referred to the above cost export revenues as a "windfall" while intervenor TREE has adopted terminology of "dividend" or "subsidy" (see for example 2006 COS proceeding transcript page 2323-24; and page 2349). In contrast, the Board in Order 117/06 noted: Net export revenue for COSS purposes is to arise after the deduction of all costs associated with export activities, thus, domestic customer classes are relieved of all costs associated with export activities. That accomplished, there is no legislative requirement for net export revenue to be distributed to customer classes within the COSS at all, let alone distributing net export revenue on the basis of generation and transmission costs alone" (page 53).

> been requested in past orders. Such quantification is vitally important given the increased risks that will accompany a debt level that may reach $20 billion by 2022[88].

The orderly process set out by the Board is consistent with the present step of “identifying and properly quantifying” Hydro’s risk, in advance of addressing the appropriate form of reserves. It is apparent the resolution of the question of the ideal form of reserves is a matter for future consideration, and no proposals for any specific reserve mechanism are today before the Board.

[88] Board Order 116/08, page 131.

4.0 COMMENTS ON MANITOBA HYDRO'S FINANCIAL FORECASTS

Manitoba Hydro's most recent Integrated Financial Forecasts filed with the Application materials (IFF09-1 and IFF10) indicate a marked change in financial position from the financial forecasts included in the 2008 GRA (IFF07-1)[89]. In particular, the following key points are noted:

- **Consolidated Debt:Equity Ratio:** IFF07-1 did not forecast the 75:25 debt to equity target being achieved within the forecast period, although the ratio remained fairly stable at 78:22 throughout the period from 2007/08 through 2017/18. By contrast both IFF09-1 and IFF10 shows the debt:equity ratio target being achieved in the near term (through at least 2011/12), but then quickly eroding to 80:20 in 2017/18 and 81:19 by 2019/20.

- **General Consumer Rate Increases:** IFF07-1 assumed annual general consumer electricity rate increases of 2.9% annually for each year from 2008/09 through 2017/18. By contrast both IFF09-1 and IFF10 assume general consumer electricity rate increases of 3.5% annually from 2012/13 through 2019/20.

In its filing, Manitoba Hydro references the period to 2020 as the "decade of investment" in which major capital investments are being made to Hydro's generation, transmission and distribution systems. During the decade of investment Hydro notes there will be a requirement to materially increase the level of debt and the debt:equity ratio will erode. The period following the decade of investment is termed the "decade of returns", when Hydro projects the debt to equity ratio will reach 51:49 by the end of that period[90].

While Hydro states domestic rate increases over the longer term are closely aligned with projected rates of inflation[91], the general consumer rate increases of 2.9% in the test years and 3.5% projected during most of the decade of investment (as compared to inflation estimates of 1.6%-2.2%) is a notable feature of Hydro's GRA filing. Where they can be sustained consistent with broad objectives of rate stability and a financially strong utility, step increases in the range of inflation would be consistent with the long-term history of the regulation of Manitoba Hydro.

4.1 PREPARING FOR THE DECADE OF INVESTMENT

Manitoba Hydro's filing underscores the terminology adopted with respect to the "decade of investment". In particular, the period is characterized by intensive capital investment, increased debt requirements,

[89] IFF07-1 was appendix 22 to the 2008 GRA.
[90] Tab 2, page 4. Manitoba Hydro 2010/11 & 2011/12 GRA.
[91] Tab 2, page 4. Manitoba Hydro 2010/11 & 2011/12 GRA.

materially increased dependable and average power resources, and current forecasts for domestic rate increases that are projected to be consistently higher than inflation.

Appropriate methods of utility regulation at this time should focus on establishing a predictable and measured rate adjustment regime, and on careful review of Hydro's costs, in particular focused on items that either bear directly on capital expenditures or their financing, or that cause material detrimental effects on Hydro's ability to secure sufficient reserve amounts. Specific comments on Hydro's costs and revenues are provided below.

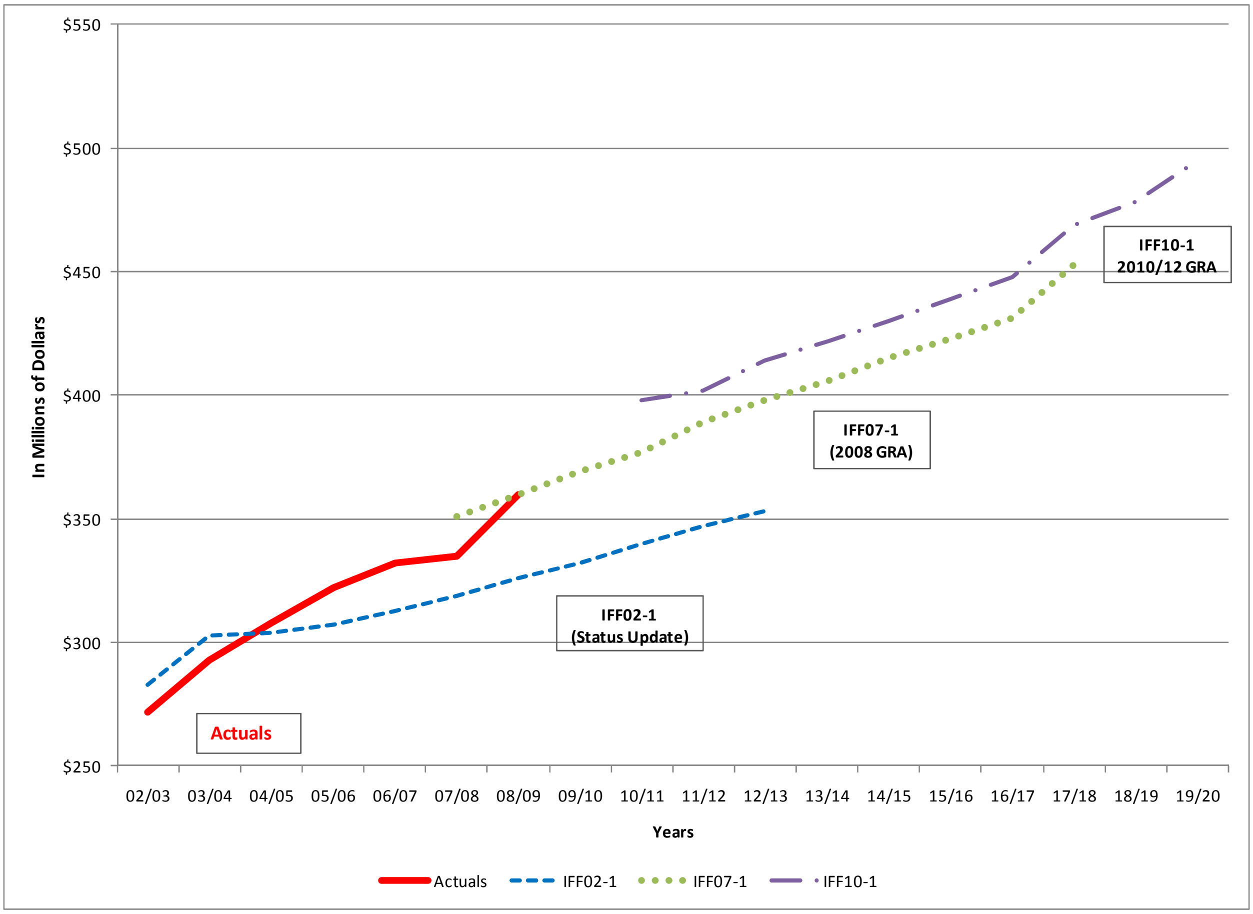
4.1.1 OM&A Cost Control

The analysis set out in Attachment B to this submission indicates the broad trend in OM&A costs. Of note is the fact that both IFF09-1 and IFF10 show a continuing trend in increased OM&A spending relative to IFF07-1 and past IFFs. This stands in contrast to Order 116/08 where the Board noted its expectations from past recommendations related to OM&A expenses have not been met[92]. A simplified summary of the OM&A values from Attachment B, focused on the relevant IFF documents from past regulatory review indicating the continuing increase in trajectory, is provided in Figure 4.1 below[93]:

[92] Order 116/08, page 92.

[93] Data sources as per Attachment B. Note that definitions of OM&A have been adjusted during this period for such matters as IFRS implications, exclusions of corporate subsidiaries, and reduced capitalization of overheads, (see Attachment B).

Figure 4.1
OM&A spending ($millions) Actual and Forecast 2002/03 to 2019/20



With respect to OM&A in 2008/09, Hydro provided information indicating 2008/09 OM&A per customer exceeded targets by approximately 2.7%, after being below targets in 2006/07 and 2007/08[94]. Hydro indicates the increase in OM&A costs in 2008/09 is primarily due to the restoration of staffing levels given high vacancy rates experienced in 2007/08 and that this staffing situation was managed in 2007/08 by deferring non-essential maintenance[95]. Hydro also attributes part of the increase in OM&A to changes in accounting policy related to overhead capitalization[96].

Table 4.1 reviews Manitoba Hydro's actual OM&A, and OM&A per customer, through 2008/09 and forecast in IFF09-1. A review of Table 4.1 indicates actual OM&A spending per customer increases at a rate beyond a standard 2% inflation rate for most years, with the exception of 2007/08 noted above. The

[94] CAC/MSOS/MH I-9 g).
[95] MIPUG/MH I-6 a) (i).
[96] CAC/MSOS/MH I-6c and d suggest $11 million of the increased OM&A in 2009/10 and 2010/11 between IFF MH08-1 and IFF MH09-1 is related to CICA accounting changes.

average annual percent increase in OM&A spending per customer between 2004/05 and 2008/09 is 3.7%, well in excess of a 2% inflation rate.

Table 4.1
Actual and Forecast OM&A per Customer[97]

Actuals	2004/05	2005/06	2006/07	2007/08	2008/09
OM&A ($000s)	298,613	310,659	323,466	322,697	359,660
# of Customers	505,666	509,791	516,861	521,599	527,472
OM&A per customer	591	609	626	619	682
per cent change		3.2%	2.7%	-1.1%	10.2%

Forecasts	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
OM&A ($000s)	371,504	379,695	403,370	411,425	419,641	428,159	436,710	445,432	466,943
# of Customers	531,804	536,267	540,756	545,215	549,623	553,968	558,286	562,580	566,841
OM&A per customer	699	708	746	755	764	773	782	792	824
per cent change	2.5%	1.4%	5.4%	1.2%	1.2%	1.2%	1.2%	1.2%	4.0%

For the forecast period, Manitoba Hydro forecasts changes to be more in line with a normal expectation of inflation plus productivity improvements, with two notable exceptions, a 5.4% increase in OM&A per customer forecast in 2011/12 and a 4.0% increase in 2017/18.

Based on this review, it is likely necessary for the Board to remain focused on this area of concern. Past practice indicates the Board has limited tools to exercise at this time in order to enforce vigilance by Hydro in practice over the level of its costs[98].

4.1.2 Normal Capital Spending

While the increased debt and capital spending during the decade of investment are driven in large part by major new generation and transmission projects. It is also important to address what might be termed

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[97] Data from MIPUG/MH I-6 c).

[98] See MIPUG Closing Submission from the 2008 GRA (Exhibit MIPUG-17) which notes as follows (page 10-2), "In the current context, as set out simply in the exhibit entitled "The Regulator's Dilemma" (Coalition Exhibit 39), the Board is challenged to set the level of Hydro's domestic revenues as a means to attempt to manage the level of Hydro's net income and consequently reserves. As noted in Board Issue #20, one simplistic interpretation of this form of regulation is that the Board does no more than manage the overall level of "rates" with no practical ability to exert normal regulatory pressures on Hydro's cost levels (whether they be O&M or capital, which remain entirely within Hydro's control). In the extreme, the logical foundation for this interpretation leads to an inevitable conclusion that, so long as the Board remains concerned about "reserve" levels (with reserve equated to Hydro's retained earnings) there is no basis or practical impact of the Board determining the necessity or prudence of any of Hydro's spending, as regardless as to the conclusion they make the Board will be effectively forced to give Hydro the rates necessary to fund this level of spending, else the level of "reserves" suffers. This outcome, where the Board is effectively neutered from doing a normal diligent regulatory review of spending, is clearly absurd".

"normal capital spending", consistent with the definition set out in IFF02-1: "All capital construction requirements excluding new major generation and/or major transmission facilities…"[99]

The Board expressed strong concerns with respect to Hydro's capital spending controls going back as far as Order 51/96 (1996 GRA) where the Board recommended that Hydro "…stringently limit its capital expenditures where safety and reliability constraints allow and apply itself to reducing long-term debt with urgency"[100]. By Order 7/03 (Status Update) the Board noted that "The Board remains concerned with the progressive growth in capital expenditures from $250 million in 1996 to $425 million in 2002. The Board reiterates its concerns expressed in Order 51/96"[101].

During the 2004 GRA, there was discussion about capital spending and its associated impacts on Hydro's debt. In particular, at that time Hydro was actively engaged in seeking approvals for the proposed Wuskwatim project and noted that absolute reduction in debt while undertaking major new revenue-generating bulk power projects was neither possible nor desirable. As noted by Hydro:

> …anytime we're expanding as we are with -- expect to be with Wuskwatim then, of course, reducing debt is -- is not possible, nor is it desirable because debt is good; that's where we get our source of funds. So borrowing for purposes of growth, as I indicated earlier, is a good thing to do. It's good for Manitoba Hydro; good for its ratepayers. So reducing debt is -- is contrary to the whole concept of growth and in itself is not – is not a good objective for Manitoba Hydro[102].

Hydro's summary provides a fair commentary on the need for debt financing to bring on new major revenue-generating capital projects; however, this same summary does not apply on a sustained basis to normal capital spending for replacements or general annual system improvements. The Board echoed this concern in Order 143/04 when it noted:

> The Board continues to be concerned with the progressive substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may be [sic] prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements,

[99] IFF02-1 at page 28.
[100] See Order 7/03 at page 90.
[101] Ibid.
[102] Transcript June 14, 2004, pages 203-204.

> Wuskwatim, Gull, Conawapa, and may be justified individually when considering each project's purposes and forecast results over the long-term.
>
> However, collectively these projects negatively impact MH's debt to equity ratio and net income in the initial years, placing increased strain on the financial stability of MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the company[103].

In Order 116/08 the Board reiterated its "prior concerns and noted that with planned major capital expansion, such concerns are now graver"[104].

The evidence in this proceeding demonstrates that Hydro's normal capital program has not yielded despite the Board's continuing directives:

- In **CEF07-1** capital expenditures total $11.610 billion over 11 years. Approximately $7.484 billion of this amount was for major new generation, transmission and DSM. The residual $4.126 billion yields an average capital spending on "normal" items of $375 million per year.

- In **CEF09-1** the total 11 year expenditures are $16.872 billion. Approximately $12.326 billion of this relates to major generation, transmission and DSM. The remaining normal capital spending is $4.547 billion or about $413 million per year average over the 11 years[105].

This comparison reflects an increase of over 10% in average annual normal capital spending, or an average annual growth rate of nearly 5% between CEF07-1 and CEF09-1. Approximately half of this amount may reasonably be cited as being consistent with CPI typical inflation over the period. No effects of any Board-encouraged cost control measures are apparent in these top-down values. There is reason for continuing concern that increases in normal capital spending will undermine any attempt to increase retained earnings through above-inflation rate increases.

[103] Board Order 143/04 page 95.
[104] Order 116/08 page 156.
[105] These figures do not include any amounts related to the "target adjustment". Manitoba Hydro states in response to PUB/MH I-66 that the target adjustment is a general provision and not related to specific projects.

4.1.3 Sinking Funds

The Manitoba Hydro Act requires the Corporation to make annual sinking fund payments to the Minister of Finance of not less than 1% of the debt and 4% of the sinking fund balance at March 31st of the previous year[106] except where exempted by the Minister. The Minister invests the sinking fund payments in securities that are authorized by Section 27(2) of *The Financial Administration Act*[107]. Maintaining sinking funds for future debt repayment has been reasonably common longstanding practice among Crown owned utilities, such as Newfoundland and Labrador Hydro, NWT Power and New Brunswick Power. In the 2008 GRA Hydro confirmed that B.C. Hydro's sinking fund requirements were removed from its obligations on all new and outstanding debt as of December 2005[108]. In Order 116/08, the Board stated:

> "...MH has been served well in the past by the obligation to have sinking funds. Yet, the Board accepts that its future benefit may be diminished due to changes in accounting standards and improvements in the capital markets[109]".

The Board went on to state:

> "out of an abundance of caution, and in light of the major capital expansion and related anticipated growth in debt levels now planned, the Board will recommend that MH seek independent advice, as well as advice from government and its credit rating agencies, as to the merits of a possible elimination of the sinking fund requirements[110]".

In response to PUB/MH I-25 b), Hydro estimates the net impact of removal of the sinking funds to be approximately $8 million per year and states the Province of Manitoba is aware of Manitoba Hydro's objective to ultimately eliminate the sinking fund requirement. However Hydro states the net impact of removal does not take into consideration potential negative impacts that may result from credit rating agency reviews (although such negative impacts are not indicated by Hydro as being likely, nor are they quantified)[111]. In the 2008 GRA Hydro has indicated that it did not believe eliminating the sinking fund

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[106] MIPUG/MH I-12 a) from the 2008 GRA.
[107] The authorized securities are detailed in the response to MIPUG/MH I -12 a) from the 2008 GRA.
[108] MIPUG/MH I – 12 d) from the 2008 GRA.
[109] Order 116/08 page 69.
[110] Order 116/08 page 69.
[111] In the current proceeding Hydro provided a response noting the liquidity levels provided by a large pool of sinking fund have been noted as a major credit rating strength factor in credit opinions provided by Standard & Poor's for the Province of Manitoba. Hydro went on to state it is unknown if the elimination of the sinking fund would negatively impact the credit rating of the Province of Manitoba through time and potentially increase Manitoba Hydro's credit spreads and borrowing costs. (MIPUG/MH II-6 a).

requirements would have any adverse effect on the borrowing rates it is able to secure[112]; its ability to access capital markets[113]; the range of borrowing instruments available to it[114]; or the debt ratings for Manitoba and related contributions of Manitoba Hydro to the provincial debt rating[115].

Given the magnitude of Hydro's planned capital program, the potential future impact of sinking fund requirements may be substantial. In addition, sinking funds inherently expose the utility to risks with respect to interest rate spreads over time, and as such serve to inject an added layer of future variability and risk into Hydro's financial forecasts. The Board should continue to encourage Hydro to pursue the feasibility of relief under the necessary sections of *The Manitoba Hydro Act.* Such relief could provide a clear measure to aid in reducing costs to ratepayers during the decade of investment and reducing risk through all future periods.

4.1.4 Export Revenues

In the short term, IFF10 assumes export revenue generally lower for the period 2011/12 through 2017/18 compared to IFF07-1 ($4.091 billion in IFF07-1 compared to $3.877 billion in IFF10). IFF10 also includes substantially lower export revenue forecasts compared to IFF09-1 – approximately $292 million – which Hydro attributes to a one year deferral in the Keeyask generating station as well as lower export prices and a stronger projected Canadian dollar[116].

The volatility in recent export revenue forecasts renews concerns expressed during the 2006 cost-of-service study review and the 2008 GRA in respect to Hydro's approach to applying "above cost" net export revenues to offsetting the costs of Hydro's general system assets (generation, transmission and distribution) so as to allow for lower domestic rates in the near-term. Instead, any such above-cost export revenues might be prioritized to building appropriate drought reserves (and aid in management of Hydro's debt) as a "preferred approach"[117].

Section 5 of this evidence provides a breakdown of the PCOSS11 results that identify the "surplus" or "above cost" export revenues. These amounts approximate $78.8 million in the 2011 forecast (per Table 5.1). This stands in notable contrast to the 2008 analysis of the same value, which totalled $137.5 million, a reduction of 43%[118].

[112] MIPUG/MH II-13 h) i from the 2008 GRA.
[113] MIPUG/MH II-13 h) ii from the 2008 GRA.
[114] MIPUG/MH II-13 h)iii from the 2008 GRA.
[115] MIPUG/MH II-13 h) iv from the 2008 GRA.
[116] IFF10 page 6.
[117] Evidence of P Bowman and A McLaren, March 16, 2006.
[118] Evidence of P Bowman and A McLaren, February 5, 2008, Table 4.1.

5.0 COST OF SERVICE STUDY AND GENERAL CONSUMER RATE DESIGN

The regulation of utilities serving different classes of customers requires tools that measure and analyze the allocation of the utility costs to each rate class. The core function of such cost-of-service study is purely analytical – it is needed as a principled, defensible and, to the extent possible, accurate measurement of the costs to service loads of varying characteristics. Rates can be ultimately established by a balancing of varying considerations, including a major (but not singular) consideration of the underlying embedded costs to serve each type of load; as such, the process of rate setting over time effectively requires accurate measurements of allocated costs arising from a properly prepared cost-of-service.

In 2006, the Board undertook a comprehensive review of Hydro's cost of service method, leading to Board Order 117/06 [119]. Manitoba Hydro's cost-of-service methods were subsequently reviewed as part of the 2008 GRA.

Manitoba Hydro provided copies of its PCOSS10[120] and PCOSS11[121] as part of its filing in the current proceeding. This review focuses primarily on PCOSS11 and Manitoba Hydro notes PCOSS11 uses the same methodology employed for PCOSS10[122]. Methods employed in developing Hydro's PCOSS11 and an assessment of the output of PCOSS11 are reviewed in the following sections.

5.1 PCOSS11 METHODS

Order 116/08 contained the following directives to Manitoba Hydro:

> "**Directive 19:** MH to re-file the COSS by January 15, 2009 on the following basis:
>
> a) As defined by Order 117/06;
> b) Incorporating diesel and exports in the same fashion as other domestic customer classes;
> c) The assigning of 50% of fixed and 100% variable thermal plant costs to the Export class;

[119] The proceeding covered 11 days of hearings, and cost in excess of $1.25 million (per MIPUG/MH-II-3(g) from the 2008 GRA), excluding MIPUG's costs which are paid for by the intervenor themselves.
[120] Appendix 11.1.
[121] Appendix 58.
[122] PCOSS11 page 1.

d) Assign DSM cost directly to the export class and add DSM energy savings to domestic load for Generation cost-sharing purposes;

e) Use the most recent actual [not forecast] export prices to establish export revenue in the COSS; and

f) Use actual [eight year] energy [SEP] prices and energy use profiles in Generation energy weighting process.

Directive 20: MH to provide and file with the Board by January 15, 2009 a revamped Marginal Cost (MC)-COSS analysis, one reflecting needed refinements to generation, transmission and distribution marginal costs. This should include specific demonstrations of how alternative MC adjustments could be applied to an embedded COSS. Among the scenarios to be explored, MH should consider the addition or blending of marginal costs to embedded costs prior to comparison to class revenues"[123].

With respect to Directive 20, Hydro indicates a meeting was held on November 24, 2009 between Manitoba Hydro and the PUB to discuss this directive. Hydro confirmed in response to PUB/MH II-180 a) that it had not to date defined a MC-COSS process, but intends to engage external consulting services in the development of a fresh approach to the COSS, including a revamped marginal cost[124]. However, past evidence before this Board indicated that adoption of marginal cost approaches consistent with the basis used in other jurisdictions (in the limited examples that exist) would in most cases not have a material effect on the results of the cost of service study as compared to embedded methods[125].

With respect to Directive 19, PCOSS11 appears to incorporate diesel and exports in the same fashion as other domestic customer classes and Hydro indicates it has used seven years of actual SEP data and future cost-of-service studies will use the full eight year average as the necessary load research data become available. These represent a reasonable implementation of the Board's directives in Order 116/08. Several other elements of PCOSS11 are not consistent with Order 116/08:

- PCOSS11 assigns the cost of gas-fired thermal plants and all the fixed and variable costs of Brandon Unit 5 coal generating station entirely to the domestic classes (no costs to exports). These methods are not consistent with Order 116/08. However, Manitoba Hydro notes gas-fired

[123] Pages 350-351. Order 116/08.

[124] Manitoba Hydro filed the terms of reference as Appendix 60 to the application. The terms of reference indicate one of the objectives of the study is to provide recommendations on how or if Marginal Cost adjustments could be made to or otherwise reflected in an embedded cost of service study.

[125] See, for example, Exhibit MIPUG-15 from the 2008 GRA, and the testimony at pages 3348-3349 of the transcript from that proceeding.

generation is almost never used to support exports and the plants provide dispatchable energy for the benefit of domestic customers, and further, by provincial legislation Manitoba Hydro can no longer use coal-fired generation to support exports. While Hydro's approach to modelling the Brandon coal costs are appropriate, the conclusion regarding natural gas is not. Natural gas resources form a component of Hydro's dependable energy serving the overall load, and permit an enhanced quantity of the exports being marketed as dependable resources rather than opportunity, and as such are a relevant component of the cost to serve exports. The appropriate approach to modeling natural gas related generation and costs is to allocate the costs to all firm loads. Although this change would improve the cost analysis in the cost of service study, the likely effect is small and this one factor alone does not undermine the overall conclusions arising from PCOSS11.

- PCOSS11 assigns DSM costs to the customer classes benefiting from the DSM programming; the same approach as used out prior to PCOSS08. Manitoba Hydro states this process reasonably assigns costs in accordance with the classes which benefit from the expenditures and is relatively simple to carry out, avoiding methodological complications associated with tracking cumulative DSM energy and capacity savings. Pursuant to the directions of the PUB, PCOSS08 had directly assigned DSM costs to the export class. However, in PCOSS08 Hydro concurrently adjusted export class energy by energy savings deemed to be associated with DSM activities carried out to date. MIPUG evidence in that proceeding indicated Hydro's approach to energy allocation created an inconsistency in the demand/supply balance assumed in PCOSS08 and as such energy should not be adjusted in this manner[126]. The treatment of DSM costs in PCOSS11 is a reasonable long-standing method and is clearly preferable to the method proposed by Hydro in PCOSS08, and as such should be accepted for this study.

- PCOSS11 uses forecast export prices and revenues arising from the underlying IFF, consistent every past Hydro PCOSS. This is not consistent with the Board's directive to use the most recent actual export prices. However, it is reasonable for Hydro to support an export revenue forecast in its cost-of-service study that is wholly consistent with the IFF parameters[127], and as such, Hydro's method should be accepted.

[126] Table 4.3, Page 33. Pre-filed testimony of P. Bowman and A. McLaren February 5, 2008.

[127] In its response to CAC/MSOS/MH I-67 a), Hydro states it is possible to have export revenues in the PCOSS that do not match those in the IFF without affecting the usefulness of the PCOSS results, the results would still be valid for minor changes in export revenue, but there is a risk that a dramatic reduction in revenues will distort results, in particular Hydro notes that the parameters used in creating the revised export forecast must comport with those underlying the forecast generation costs.

Further, Manitoba Hydro states that it assigned only the portion of trading desk costs, MISO and MAPP fees that can be directly attributed to export sales activities to the export class. Hydro indicates the remaining costs would largely still be incurred in order to achieve the dependable supply required to serve domestic customers[128].

The net result of the above method changes is that PCOSS11 directly assigns fewer costs to the export class than PCOSS 08, and fewer than would otherwise be consistent with the Board's directives. However, outside of specific relatively small adjustments noted above, it is clear that the results of PCOSS11 provide useful and compelling results can be relied upon in this proceeding.

At a high level, the COS results indicate the following key points:

- **Usefulness of COSS Results for Measuring Cost Allocation:** Contrary to Hydro's assertion that the cost-of-service study methods should not be relied upon, a review of Hydro's methods makes it apparent that PCOSS10 and PCOSS11 are largely consistent with cost causation principles for the functionalization, classification and allocation of all material cost categories.

- **Policy-Related Matters:** PCOSS11 includes a number of material variations from normal causation principles in related to a series of policy-related items. Each of these items can be quantified and tracked, to ensure the analytical aspects of the COS can be derived cleanly prior to implementation of these added allocations. The three specific examples noted are: the direct assignment against exports of the Uniform Rate related costs, the Affordable Energy Fund related costs, and the allocation of "Net Export Revenues" against total allocated costs of each domestic class (e.g., including distribution and customers service functions).

- **Class Results:** The cost-of-service analysis allows for very useful observations into the costs to serve various classes. A few examples are set out in Table 5.1 and Figure 5.1 below. As an example, the results with respect to the residential customer class are discussed below:
  - Costs – These customers drive average costs for bulk power of 3.79 cents/kW.h (for every kW.h consumed at the meter). To this, 0.57 cents/kW.h must be added for subtransmission and 3.62 cents/kW.h for distribution. The total cost to serve residential customers is therefore 7.98 cents/kW.h (at row 4 of Table 5.1).
  - Revenues - As to revenues, the average revenue from residential customers is 7.08 cents/kW.h (row 5).

[128] Summarized from page 8 PCOSS11.

- Net Result before Policy-Related Credits – Overall, residential ratepayers fail to pay their full costs by 0.90 cents/kW.h. In the event "surplus" export revenues were not credited back to customers in the cost of service study through various means, this is the amount rates would need to be adjusted to fully recover the remaining costs.
- After the fully allocated cost-of-service study assigns costs and revenues, PCOSS11 makes certain other policy based adjustments that do not have a basis in normal cost-causation principles, but reflect past directives of the Board including:
  - The Board's directive with respect to Uniform Rates results in an additional credit of 0.26 cents/kW.h (row 8 of Table 5.1).
  - Export Credit - Per PCOSS practice as directed by the Board, all as yet unallocated export revenues (approximately $46 million) are credited against the total allocated costs of all functions. The residential class credit approximates 0.30 cents/kW.h (row 10 of Table 5.1).
- Resulting Surplus/Shortfall – For this class, the remaining shortfall in rates is 0.33 cents/kW.h (row 11 of Table 5.1).

A similar analysis was prepared for certain other classes shown in Table 5.1 (and can be completed likewise for any class in PCOSS08)[129]. A key observation from Table 5.1 is that as a result of the 11% average across-the-board rate increases since July 2008, several rate classes are now paying revenues virtually at or in excess of the costs to serve the class before the allocation of policy-related adjustments or net export revenues[130].

[129] 1. Total costs (line 4) are taken from Schedule B1 of PCOSS11 with the exception of exports, where total coasts are reduced by $20.025 million reflecting the uniform rates adjustment.

2. Bulk power, subtransmission, distribution and customer related costs are shown after the creation of an export class, but before net export revenue allocation and are calculated in Attachment C.

3. Subtransmission, distribution and customer related costs are taken from Schedule E1 from PCOSS11 with the net export revenues removed.

4. Total PCOSS Sales Revenue (line 5) taken from Total Adjusted Revenue column of Schedule C13 of PCOSS11.

5. Total class metered energy (line 12) taken from Schedule B2 – Customer, Demand, Energy Cost Analysis – Metered Energy column.

6. Affordable Energy Fund Expenditure (line 9) from page 3 of PCOSS11.

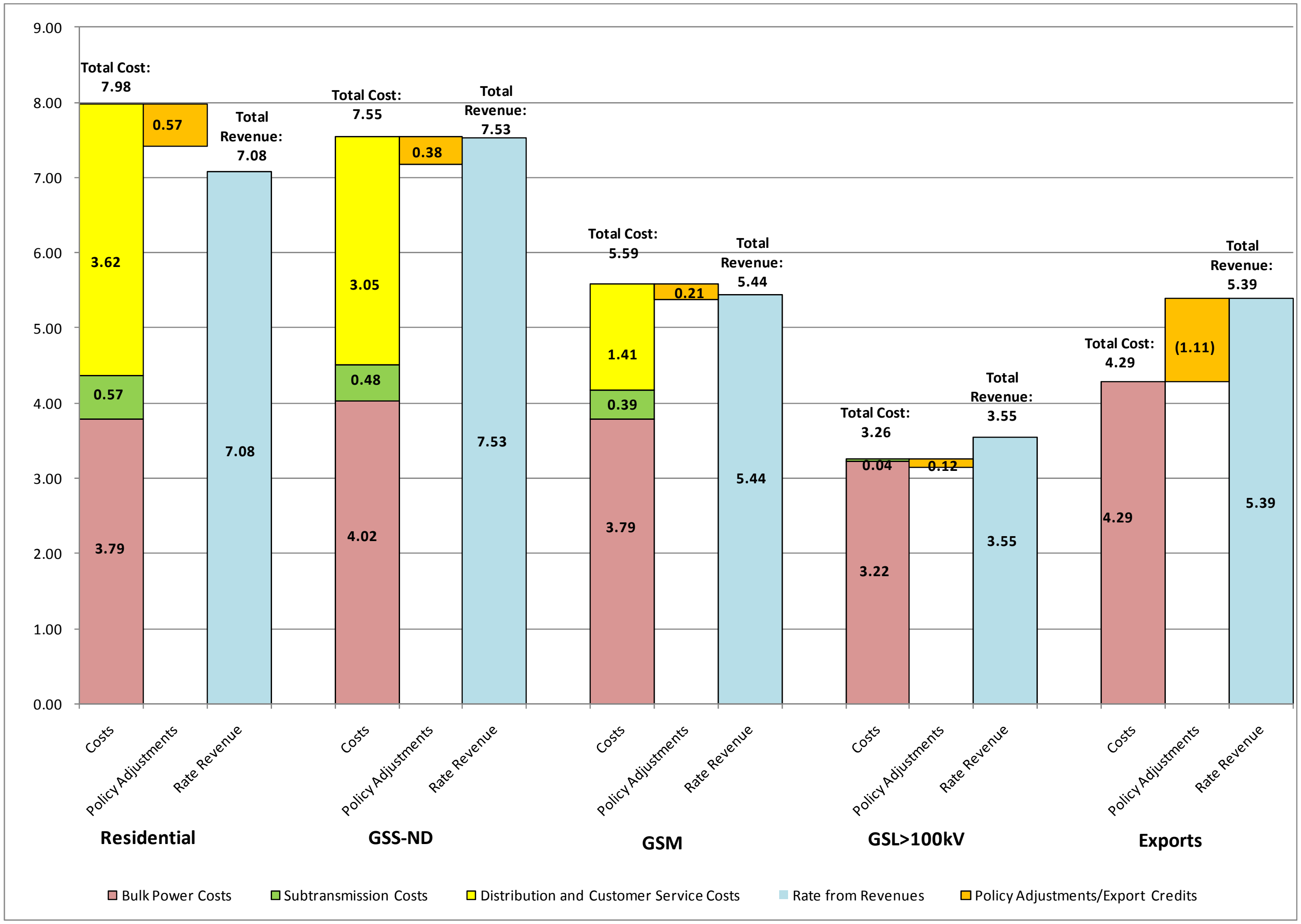
7. Net Export Revenue Allocation (line 10) from Schedule B1 of PCOSS11 – Revenue Cost Coverage Analysis – Net Export Revenue column.

[130] 5% effective July 2008, 2.9% effective April 2009 and 2.9% effective April 2010 on an interim basis.

Table 5.1
Levelized RCC Ratios per kW.h PCOSS11

	Residential		GSS-ND		GSM		GSL>100kV		Exports	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs										
1 Bulk Power Costs	$256.32	3.79	$63.19	4.02	$114.28	3.79	171.02	3.22	$305.23	4.29
2 plus: Subtransmission-related	$38.75	0.57	$7.58	0.48	$11.70	0.39	0.00	0.00	$0.00	0.00
3 plus: Distrib. and Cust. Serv.	$245.29	3.62	$47.87	3.05	$42.48	1.41	2.32	0.04	$0.00	0.00
4 Total Costs	**$540.37**	**7.98**	**$118.64**	**7.55**	**$168.45**	**5.59**	**173.34**	**3.26**	**$305.23**	**4.29**
Rates										
5 Total PCOSS Sales Revenue	**$479.64**	**7.08**	**$118.33**	**7.53**	**$164.08**	**5.44**	**188.68**	**3.55**	**$384.06**	**5.39**
Surplus/Shortfall before Net Export Credits										
6 Rates compared to costs (5-4)	**($60.72)**	**(0.90)**	**($0.31)**	**(0.02)**	**($4.38)**	**(0.15)**	**$15.34**	**0.29**	**$78.84**	**1.11**
7 Revenue:Cost Ratio (Net of Policy Adjustments and Export Credits) (line 5/ line 4)	**88.76%**		**99.74%**		**97.40%**		**108.85%**		**125.83%**	
Policy Adjustments										
8 Uniform Rate Credit	$17.81	0.26	$1.58	0.10	$0.04	0.00	$0.00	0.00	($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	$20.54	0.30	$4.38	0.28	$6.24	0.21	$6.50	0.12	($46.81)	(0.66)
11 **Surplus/(Shortfall) after net export revenue credits** (6+8+9+10)	**($22.38)**	**(0.33)**	**$5.66**	**0.36**	**$1.90**	**0.06**	**$21.84**	**0.41**	**($0.00)**	**(0.00)**
12 Total Class Metered Energy (GW.h)	6,772		1,571		3,015		5,311		7,122	

Figure 5.1
Select Customer Class Costs and Revenues per PCOSS11 Data



5.2 ASSESSMENT OF OUTPUT OF PCOSS11

Table 5.1 provides the key output of PCOSS11 for a sample of customer classes. The results summarized in Table 5.1 fit with reasonable expectations from the Cost of Service study and include the following:

- **Domestic Bulk Power:** Residential and GS Small bulk power costs are modestly higher than large users such as GSL>100kV due to added line losses between the bulk power system and the meter. This result is both expected and consistent with cost causation principles. The GS Small Non-Demand results reflect a somewhat higher cost for bulk power, which may be due to the load profile of the customer (i.e., they may tend to peak at more expensive times than, for example, residential customers who are served at a similar voltage).

- **Export Bulk Power:** Export bulk power costs are higher than domestic classes, as they properly have added costs directly assigned to them (such as purchased power). The current PCOSS10 approach may understate the true embedded costs to serve exports, as certain potentially higher-than-average cost resources may be pursued by Hydro based on the ability to secure large revenues in the export market; however, in this analysis these resources are simply added into the common "pool" of generation assets. In this vein, there may be merit in considering items such as System Supply Enhancements pursued for economic reasons[131] with a similar treatment to purchased power costs – that is, to have them fully funded by exports to reflect the economic driver of the activity.

- **Subtransmission and Distribution:** The costs of subtransmission and distribution functions are properly allocated against the classes that use these systems. For smaller users, like the GS Small class, these costs comprise nearly half of the costs to serve class loads. For larger customers, such as Industrial (GSL >100 kV), these costs are negligible.

- **Revenues Compared to Fully Allocated Costs:** For the first time in since the comprehensive 2006 cost-of-service study review, many rate classes are paying or nearly paying the fully allocated unit costs to serve them prior to receiving any export or policy based revenue credits. Three customer classes are above 100% (GSL 30-100 kV, GSL >100 kV and Lighting) and a further three are within the "reasonable" (95-105) distance of 100% (GS Small - Non-Demand,

[131] Many projects the utility undertakes to renew capital works will serve to enhance the output of the system, due to modern technologies, etc. By economic SSEs, this concept refers only to those projects that are solely undertaken for economic/enhanced output reasons. This can include, for example, re-runnering a plant that otherwise is fully operational because the added output from modern runners more than compensates for the project cost.

GS Small – Demand, GS Medium). This contrasts with the situation at the time of the 2008 GRA where only one customer class was above 100% RCC before any allocation of net export credits – the Area and Roadway Lighting class (at 101.7%)[132]. At the time of the 2008 GRA this result was relied on to justify the Area and Roadway Lighting class receiving a lower than average rate increase[133]. Other classes have rates that are below the fully allocated levels to various degrees – ranging from approximately $4.4 million for GSM, to as high as $61 million for Residential. These results are summarized in Table 5.2 below[134].

Table 5.2
PCOSS11 Results

	Total Cost	Class Revenue	Surplus/ (Shortfall) before Policy Based Credits	RCC Before Policy Credits
Residential	$540,365	$479,644	($60,721)	88.8%
GSS-ND	$118,628	$118,331	($297)	99.7%
GSS-D	$114,981	$114,720	($261)	99.8%
GSM	$168,455	$164,078	($4,377)	97.4%
GSL 0-30kV	$80,204	$70,730	($9,474)	88.2%
GSL 30-100kV	$32,915	$33,070	$155	100.5%
GSL >100kV	$173,341	$188,679	$15,338	108.8%
Lighting	$19,574	$20,109	$535	102.7%
SEP	$1,006	$852	($154)	84.7%
Total General Customers	$1,249,469	$1,190,214	($59,255)	95.3%
Diesel	$12,375	$4,793	($7,582)	38.7%
Total Domestic	$1,261,844	$1,195,007	($66,837)	94.7%

[132] Page 2 of MIPUG/MH-I-25 b) from the 2008 GRA, third column.
[133] See Board Order 116/08 at page 287, "MH has proposed a 1% increase in the ARL rate. City of Winnipeg raised its continuing claim of the overpayment by municipal lighting customers relative to costs being allocated to the class in the embedded cost COSS. As this class has almost always been charged more than 105% of its allocated costs, MH did not dispute the City of Winnipeg's suggestion that the accumulated sum of "overpayments", relative to an RCC of unity, totals in the multi-million dollars. The City of Winnipeg did not request a refund, but rather suggested that ARL rates remain unchanged until a RCC of 1.00 is achieved". At page 309 the board notes, "The Board agreed with the position advanced by the City of Winnipeg and, by Order 90/08, did not approve any rate increase for the Area and Roadway Lighting class for either July 1, 2008 or April 1, 2009".
[134] All data from Schedule B1 of PCOSS11. Class Revenue does not include uniform rate credits.

The total export revenue available for "credit" to the other ratepayers in PCOSS11 (what Hydro referred to in the 2006 Cost of Service hearing as "above cost revenue") is $79 million[135].

5.3 RATES FOR GENERAL CONSUMERS

Hydro's application requests rate increases for all general consumer rate classes of 2.9%, with the exception of the Area and Roadway Lighting class. This section reviews Hydro's rate proposals for the General Consumer rate classes.

Hydro's largely across-the-board rate proposals for General Consumers are simple, but are not supported by the material included in the GRA filing. Hydro has adopted rate objectives to have a long-term target of having all class Revenue Cost Coverage (RCC) ratios in the range of 95% to 105%, and further that all classes should be gradually moved toward RCCs of unity. Hydro states attainment of this objective will take longer than anticipated given the across-the-board increases being proposed in the Application[136].

As noted earlier in this section, Hydro's cost-of-service study is largely consistent both with standard cost causation principles and the Board's previous directions. It provides useful information that can be relied upon to support rate design and rate making objectives. As summarized in Table 5.1, there is evidence that 6 of 9 major rate classes are currently paying rates that approximate the costs to serve them (or are above this level) even before the allocation of any surplus export revenues. In this context, these classes largely merit a class-specific level of rate adjustment that is close to the core benchmark targeted in the respective IFF forecasts. Classes that remain well below this level (notably GSL 0-30 kV and Residential) merit rate adjustments in excess of the benchmark level. Manitoba Hydro's requested across-the-board rate increase for 2011/12 should be modified so as to target modestly differential rate increases by class, as these can be accommodated within Hydro's rate policy guidelines, focused primarily on upward adjustment to the proposed rates for classes with RCC ratios in Table 5.2 well below unity.

[135] As shown on row 6 of Table 5.1. The $67 million shown on Table 5.2 is net of approximately $12 million in export revenues used to address Affordable Energy Fund Expenditures.
[136] Tab 10, Page 2. Manitoba Hydro 2010/11 & 2011/12 General Rate Application.

6.0 INDUSTRIAL RATE DESIGN

Testimony in previous GRAs prepared and submitted on behalf of MIPUG reviewed specific concerns with respect to Manitoba Hydro's current industrial rate design.

For this proceeding, Board Order 17/10 noted the Board did not include consideration of any Energy Intensive Industrial Rate ("EIIR") within the scope of this GRA review. The Board noted that should Manitoba Hydro advance consideration of an EIIR, a separate timetable will be required. Manitoba Hydro has since notified the Board that it is initiating further consultation with customers and other parties in an effort to move toward a consensus on the terms and structure of needed evolution in industrial rate design in this province. In this regard, it is noted that cooperative discussions are occurring towards possible industrial rate changes, for future PUB review.

As a result, matters related to new proposals for industrial rate design are appropriately addressed at a future date and not as part of the current proceeding.

Therefore the only substantive issue with respect to industrial rate design before the Board in the current proceeding relates to the determination of demand related charges. A review and recommendations with respect to this topic are provided below.

6.1 DEMAND CHARGES

There are two demand related items affecting larger customers that require consideration in the present proceeding: (a) the demand billing concession program for which Hydro is seeking approval to finalize, and (b) the elimination of the winter ratchet. These items are addressed concurrently.

On August 7th, 2009, Manitoba Hydro applied to the PUB for ex parte approval of temporary demand billing concessions for certain General Service Large and Medium Customers. Manitoba Hydro noted demand charges are fixed, rather than variable charges. In times of economic downturn, full process demand is often still needed to maintain production even if energy purchases (kW.h) are reduced. The outcome tends to be a notable increase in the customer's average "per unit" electricity cost. This can arise for two reasons: first, if a customer experiences a lower load factor within a given month (e.g., by operating only day shifts, where previously both day and night shifts operated) their consumption of energy will decline but not their consumption of demand; second, where consumption of demand is also reduced on an actual basis in a given month (through lower peak loads) there may be no reduction in the customer's "billing demand" which can be pegged based on "ratchet" terms linked to the previous winter's load. Manitoba Hydro was ordered to eliminate any such ratchet provision going back as far as April 1, 2004, but delays in this revision led to the last PUB ordered date for elimination as being ahead of the winter of 2009/10 (but no later than September 30, 2009); Manitoba Hydro actually implemented the elimination of the winter ratchet effective December 1, 2009 .

The Board stated in Order 126/09, in regard to the Hydro demand billing concession application, that the forecasts as to uptake are based on assumptions that cannot be verified until after the proposal runs its course. The Board found that it was in the public interest to provide for immediate "cash flow" relief to qualifying customers, in effect rejecting Hydro's proposal for billing concessions. The Board indicated it would subsequently examine and determine whether the relief should be altered or made permanent (i.e. "relief" amounts written off by Manitoba Hydro rather than repaid by customers) when the interim Order is finalized.

In a letter to the Board dated November 18, 2009, Manitoba Hydro noted a number of customers expressed concern the program has been approved for billing deferral only and not for a full concession. Manitoba Hydro also noted that some customers indicated that though they may be eligible for the program, they opted not to apply because of the uncertainty regarding the concession.

The demand billing concession program ran from June through November 2009. At the time of its 2010/11 & 2011/12 GRA filing Manitoba Hydro estimated the program involved 10 accounts and approximately $2.0 million in demand concession deferrals. Manitoba Hydro's 2010/11 & 2011/12 GRA requests approval to finalize Order 126/09 and make permanent the demand concessions under the program. Manitoba Hydro is not today seeking any new orders in respect of the termination of the demand ratchet.

In reviewing Manitoba Hydro's requested approvals, the following points are noted:

- The practical relief provided to customers by the interim approved billing demand concession program, as opposed to Hydro's current proposal, is extremely limited. The net effect of the interim approved program is akin to that of a loan from the utility. Given the purpose and intent of the program design, it is not apparent that this approach meets any reasonable program design objectives (i.e., there is no indication or evidence that customers had a shortage of cash or loan facilities; the application indicates the issue was one of cost).

- From the program uptake, it is clear that there were benefits to Manitoba from continued production at the eligible facility or facilities during the period noted. Manitoba Hydro noted the temporary billing concession would temporarily reduce Manitoba Hydro's revenue but is intended to mitigate the risk of larger potential revenue losses and greater impacts on the Manitoba economy in the event of a prolonged company shutdown or closure.

- Over the 2009 period, Manitoba Hydro and customers not affected by the demand concession program or the winter ratchet (residential or general service small customers) did not suffer any adverse rate or revenue impacts from the level of larger customer demand revenues. In particular, the enhanced ratchet revenues from excessive delays in implementing relief from this provision are in excess of the revenues that would be foregone by now approving Hydro's proposed concession[136].

- The concessions relate only to the demand portion of the customer's bill. No concessions were provided related to the energy portion of the customer's bill, which were charged in full each month.

Ultimately, Manitoba Hydro's demand billing concession program temporarily mitigated a long-standing deficiency in its General Service Large rate design; that is, the combination of the high demand charge and the winter ratchet are well above embedded costs of serving the demand. The effect of this structure is that demand charges can create unintentionally high unit-energy cost increases when customers lower their energy usage relative to their demand. Manitoba Hydro's demand billing concession program was an unfortunately necessary response given the economic conditions and its rate design for these customers. The Board should approve as permanent and final the demand billing concessions offered under the program, as proposed by Hydro.

Future improvements to demand-related price signals are properly addressed as part of the ongoing industrial rate design discussions.

[136] Manitoba Hydro indicates winter ratchet savings that would have accrued to customers in the GSL and GSM rate classes had the winter ratchet been eliminated ahead of December 1, 2009 were approximately $3.24 million for the period from June 2009 through November 2009 and $1.04 million for October and November 2009.

ATTACHMENT A

RESUMES

PATRICK BOWMAN
PRINCIPAL AND CONSULTANT

EDUCATION:

University of Manitoba
MNRM (Natural Resource Management), 1998

Prescott College
BA (Human Development and Outdoor Education), 1994.

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

1998 – Present *Research Analyst/Consultant/Principal*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory reviews of electrical and gas utilities in four Canadian provinces. Prepare evidence and review testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability.

- **For Yukon Energy Corporation (1998-present)**, analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters. Prepare analysis of major capital projects, financing mechanisms to reduce "rate shock" to ratepayers, as well as revenue requirements.

- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government round table on competitiveness of Yukon economy. Coordinate development of options for government rate subsidy program. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

- **For Northwest Territories Power Corporation (2000-present)**, provide technical analysis and support regarding General Rate Application. Assist in preparation of evidence, filings before the Northwest Territories' Public Utilities

Board, and related issues. Appear before PUB as expert in cost of service and rate design matters, and on system planning (Required Firm Capacity) review.

- **For Manitoba Industrial Power Users Group (1998-present)**, prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters in rate proceedings, as well as cost-of-service methodology hearing. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures and surplus energy rates.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters.

- **For NorthWest Company Limited (2004-2006),** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

- **For Nexen Chemicals, Inc. (2000)**, review options for subscribing to curtailable service rates.

- **For Columbia Power Corporation/Columbia Basin Trust and Municipal Interveners (2000),** review evidence and prepare analysis on major transmission line project for Public Convenience and Necessity hearing before the British Columbia Utilities Commission.

- **For the City of Yellowknife (1999)**, prepare preliminary analysis of policy options and planning process for development of a municipal piped propane distribution system.

- **For the Government of the Northwest Territories (1999)**, prepare analysis of policy alternatives to facilitate supply of natural gas to local communities in the event of a Mackenzie Valley pipeline being constructed.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in development of local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Socio-economic assessment work related to forestry planning in Manitoba and Saskatchewan. Support to two local communities in development of negotiation position for resolving outstanding compensation related to hydro projects in Northern BC. Also conducted assessment of socio-economic impacts of policy options for floodplain management, and strategic planning for resource management board.

- **For Yukon Energy Corporation (2005-Present),** preparation of Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board; provided expert testimony before the YUB. Project Manager for the Mayo B hydroelectric project planning phase. Participate in preparation of regulatory materials for Mayo B Application to the Yukon Utilities Board under Part 3 of the Yukon Utilities Act.

- **For Northwest Territories Energy Corporation (2003-2005)**, provide analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.

- **For Kwadacha First Nation and Tsay Keh Dene (2002-2004):** Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review assessment of options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

- **For Manitoba Hydro Mitigation Department (1999-2002)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

- **For International Joint Commission (1998)**, analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of other floodplain management policies.

  For Nelson River Sturgeon Co-Management Board (1998 and 2005), an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

Government of the Northwest Territories **Yellowknife, NT**

1996 - 1998 *Land Use Policy Analyst*

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

Natural Resources Institute **Winnipeg, MB**

1996 - 1998 *Researcher*

Conducted research on surface rights allocation and access for mining, with particular emphasis on implications of government actions undermining mineral rights tenures. Also undertook analysis of Manitoba's Registered Trapline System and implications for Aboriginal trappers; also, an economic assessment of the property rights system inherent in the provincial Registered Trapline System policy and its implications on efficiency in allocation of the furbearer resource.

PUBLICATIONS: G*overnment Withdrawals of Mining Interests* in Great Plains Natural Resources Journal. University of South Dakota School of Law. Spring 1997.

Legal Framework for the Registered Trapline System in Aboriginal Trappers and Manitoba's Registered Trapline System: Assessing the Constraints and Opportunities. Natural Resources Institute. 1997

Land Use and Protected Areas Policy in Manitoba: An evaluation of multiple-use approaches. Natural Resources Institute. (Masters Thesis). 1998

Electrical Rates in Yukon. Submission by Yukon Development Corporation to Yukon "Government Leader's Economic Forum Series" on Tax Reform and Competitiveness. 1999.

Review of Red River Basin Floodplain Management Policies and Programs. Prepared for Red River Basin Task Force of the International Joint Commission. 1998.

Patrick Bowman Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission	NorthWest Company (commercial customer intervenor)	2004	No
Nunavut Power (Qulliq)	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission	NorthWest Company (commercial customer intervenor)	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	Manitoba Public Utilities Board	Manitoba Industrial Power Users Group (MIPUG)	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2009-10	Pending
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	Board of Commissioners of Public Utilities of Newfoundland and Labrador	Newfoundland Industrial Customers	2010	Pending

12/9/2010

InterGroup® CONSULTANTS

ANDREW McLAREN
PRINCIPAL AND CONSULTANT

EDUCATION: **Natural Resources Institute, University of Manitoba**
MNRM (Master's of Natural Resources Management), 1999

University of Manitoba
Bachelor of Science (Environmental Science), 1996

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

2000 - Present *Research Analyst/Research Consultant/Consultant/Principal*

Regulatory economic analysis and socio-economic impact assessment experience, primarily in the energy and water resource management fields.

Regulatory Economics

Conduct research analysis for regulatory reviews, primarily of electric utilities. Prepare evidence and regulatory filings and review testimony for regulatory proceedings.

- **For Northwest Territories Power Corporation (2000-present)**, primary responsibility for coordinating and developing all aspects of the ratebase and revenue requirement sections for the 2006/08 General Rate Application. Provided technical analysis regarding the Corporation's 2001/03 General Rate Applications and ongoing regulatory support. Responsibilities have included the preparation of evidence and filings before the Northwest Territories Public Utilities Board. Other responsibilities have included assistance on economic evaluation of major capital projects.

- **For Manitoba Industrial Power Users Group (2001-present)**, prepare analysis for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users, including testimony before the Manitoba Public Utilities Board in the 2006 Cost-of-Service Study hearing and the 2008 GRA.

- **For Yukon Energy Corporation (2001-present)**, Review secondary and interruptible industrial sales options from other jurisdictions in Canada. Provide technical analysis and support regarding applications to the Yukon Energy Board.

- **For Qulliq Energy Corporation (2008 – Present),** Lead consultant responsible for assisting QEC with preparation of the 2010/11 General Rate Application. Also assisted with other regulatory filings including fuel rider applications and capital project permit applications.

- **For British Columbia First Nations Energy and Mining Council (2009)** Provided technical services related to the Section 5 Transmission Inquiry before the British Columbia Utilities Commission. Prepared submissions on behalf of the BCFNEMC for filing with the BCUC related to First Nations interests in transmission planning.

- **For Yukon Development Corporation (2001-2007),** prepare analyses of rate options and rate subsidy program impacts as well as contribute to discussion papers on modifications and options for on-going subsidy program.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** preparation of analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Submitted pre-filed testimony (with Patrick Bowman) on behalf of the Island Industrial Customers in regards to the Newfoundland & Labrador Hydro 2006 General Rate Review before the Board of Commissioners of Public Utilities. Lead consultant for the Industrial Customers in a working group with NLH to develop a marginal cost based rate proposal.

- **For NorthWest Company Limited (2004-2005),** review rate application and rider applications, provide analysis and prepare filings before the Nunavut Utility Rates Review Council.

- **For Government of Northwest Territories (2005),** prepare modeling tools and provide analysis and discussion paper on forecast spending for the Territorial Power Support Program.

- **For Electronics Recycling Programs in Nova Scotia; Saskatchewan and British Columbia (2008-Present),** Developed forecasting methods and calculations of Environmental Handling Fees (EHFs) for electronics recycling. Prepared report for submission to Ministers responsible for the programs and public review.

- **For two Northern British Columbia First Nations,** Provide support and analysis related to potential claims for past and ongoing effects from major hydroelectric development. Review economic casework related to changes to energy supply options for the communities including potential for interconnecting to the BC Hydro grid or development of local hydroelectric or wind generation.

ATTACHMENT B - FINANCIAL RESULTS AND FORECASTS

Integrated Financial Forecasts

In the current proceeding, Manitoba Hydro has provided three different sets of Integrated Financial Forecast (IFF) information as part of its Application:

- IFF08-1 – Consolidated Integrated Financial Forecast[137];

- IFF09-1 – Consolidated Integrated Financial Forecast[138]; and

- IFF10 – Integrated Financial Forecast[139].

Manitoba Hydro has also filed a 20 year financial outlook[140] for the years 2009/10 – 2028/29. In addition to the financial information filed in this proceeding, information related to previous IFFs helps provide relevant context to evaluate Hydro's current financial position. IFFs reviewed in this respect have included:

- IFF02-1 which Hydro indicates the Manitoba Hydro Board used in setting the debt/equity target of 75:25 by 2011/12[141];

- IFF03-1 which was included with the 2004 General Rate Application[142];

- IFF04-1 which was included with Hydro's January 2005 Application in support of a 2.25% conditional interim rate increase[143];

- IFF-05-1 which is the IFF Hydro submitted when asked to identify the information it considered in making the decision to forego the October 1, 2005 conditionally approved rate increase of 2.25%[144];

[137] Appendix 21 to the 2010/12 GRA.
[138] Appendix 5.2 to the 2010/12 GRA.
[139] Appendix 76 to the 2010/12 GRA.
[140] Appendix 16 to the 2010/12 GRA.
[141] PUB/MH I -23 a) from 2008 GRA.
[142] Appendix 4.1 of 2004 GRA.
[143] Tab 2 of January 2005 Application to Implement General Rate Increase.
[144] Appendix 5.3 to the 2008 GRA, rate increase forego from page i.

- IFF06-3 – Consolidated Integrated Financial Forecast[145];

- IFF06-4 Statements[146]; and

- IFF07-1 Integrated Financial Forecast[147].

This section contrasts Hydro's actual performance[148] and forecasts with respect to key financial indicators in the different IFFs. The primary focus of this review is a comparison of IFF07-1 (the IFF primarily reviewed as part of the 2008 GRA process) and IFF09-1, which is the IFF originally included with Hydro's 2010/11 & 2011/12 GRA. For some financial indicators, the recently provided IFF10 is also described.

Debt to Equity Ratio

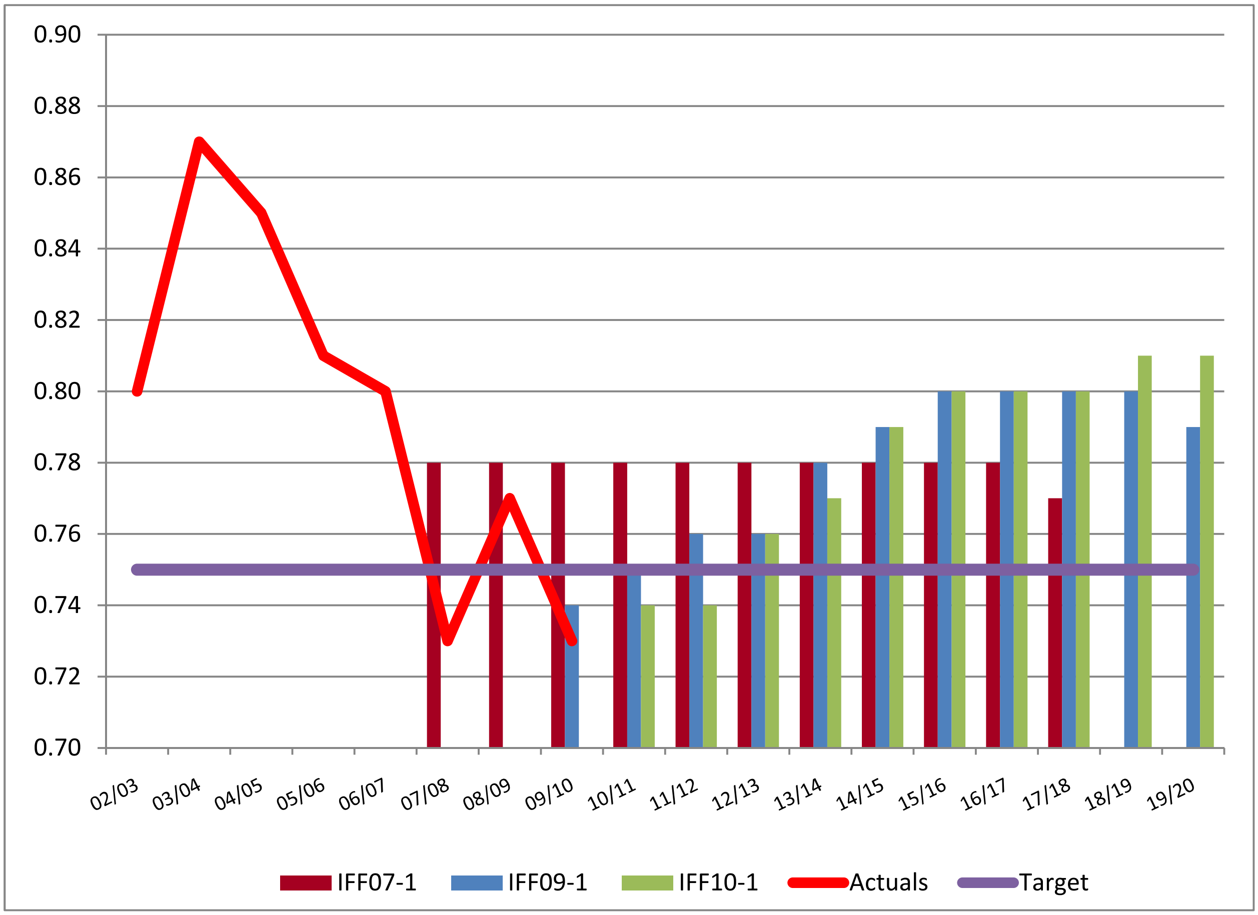
Manitoba Hydro has previously noted that its Board adopted a consolidated Debt/Equity target of 75:25 by 2011/12 in IFF02-1[149]. Hydro states in IFF09-1 that recent favourable water flow conditions enabled the achievement of an equity target of 25% in 2008/09 for the first time in Corporate history. However Hydro also notes that due to major investments in the generation and transmission system over the next decade, this ratio is projected to regress late in the IFF09-1 forecast period[150]. IFF10 projects Manitoba Hydro's consolidated debt:equity ratio to be 74:26 through 2011/12, eroding to 81:19 in 2019/20[151].

Figure B.1-1 provides a comparison of the consolidated debt ratios for from IFF07-1, IFF09-1 and IFF10. Figure B.1-1 also includes actuals for the years available. A review of Figure B.1-1 indicates that for the years 2009/10 through 2012/13, IFF09-1 and IFF10 show an improved debt to equity ratio forecast compared to IFF07-1 (i.e., an improved financial position). While Hydro appears to attribute this largely to favourable waterflow conditions, actual rate increases in excess of those forecast in IFF07-1 have contributed as well. However, for years 2014/15 through 2017/18, debt to equity ratio erodes in IFF09-1 and IFF10 compared to IFF07-1.

[145] Appendix 5.2 to the 2008 GRA.
[146] Appendix 5.1 to the 2008 GRA.
[147] Appendix 22 to the 2008 GRA.
[148] Actual information in this section is taken from the response to PUB/MH I-27, PUB/MH I-1a (revised) and CAC/MSOS/MH I-128 from 2010/12 GRA; Coalition/MH II-18a from 2008 GRA and the Manitoba Hydro 59th Annual Report.
[149] PUB/MH I -23 a) from the 2008 GRA.
[150] Page 16. IFF09-1.
[151] As per page i of IFF10-1.

Figure B.1-1

Comparison of Consolidated Operation Debt Ratios[152]



The reasons for this erosion in the debt:equity ratio in 2014/15 and beyond merit consideration. A number of factors may contribute to this erosion:

- **Retained Earnings:** As retained earnings represent the equity portion of Manitoba Hydro's debt:equity calculation, a review of trends in retained earnings is a reasonable starting point for comparison purposes.

- **Domestic Load Levels and Rates:** In its application, Hydro notes IFF09-1 forecasts lower domestic rates throughout the forecast period relative to IFF08-1 and lower net export revenues

[152] Data for IFF07-1 Debt Ratios from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Consolidated Operating Statement (p.23). IFF09-1 data from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Consolidated Operating Statement (p. 24). IFF-10 debt ratio data obtained by subtracting Equity Ratio from 100%--Equity ratio from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Consolidated Operating Statement (p.23). 2003-10 Actual data from Manitoba Hydro 59th Annual Report (p.100).

in the early portion of the forecast[153]. A reasonable point of analysis for the merits of this assertion is a comparison of total revenues, broken down into domestic and export, and also an analysis of the cumulative level of domestic rate increases, per Section B-2 below.

- **Capital Spending:** Increasing capital costs are often cited as another reason for the erosion of the debt:equity target. A comparison of Net Plant in Service is provided in section B-3 of this Attachment.

- **OM&A Expenses:** The Board and intervenors have for many years been concerned with respect to the ongoing increases in Hydro's OM&A expenses. Trends in OM&A are reviewed in Section B-4 of this Attachment.

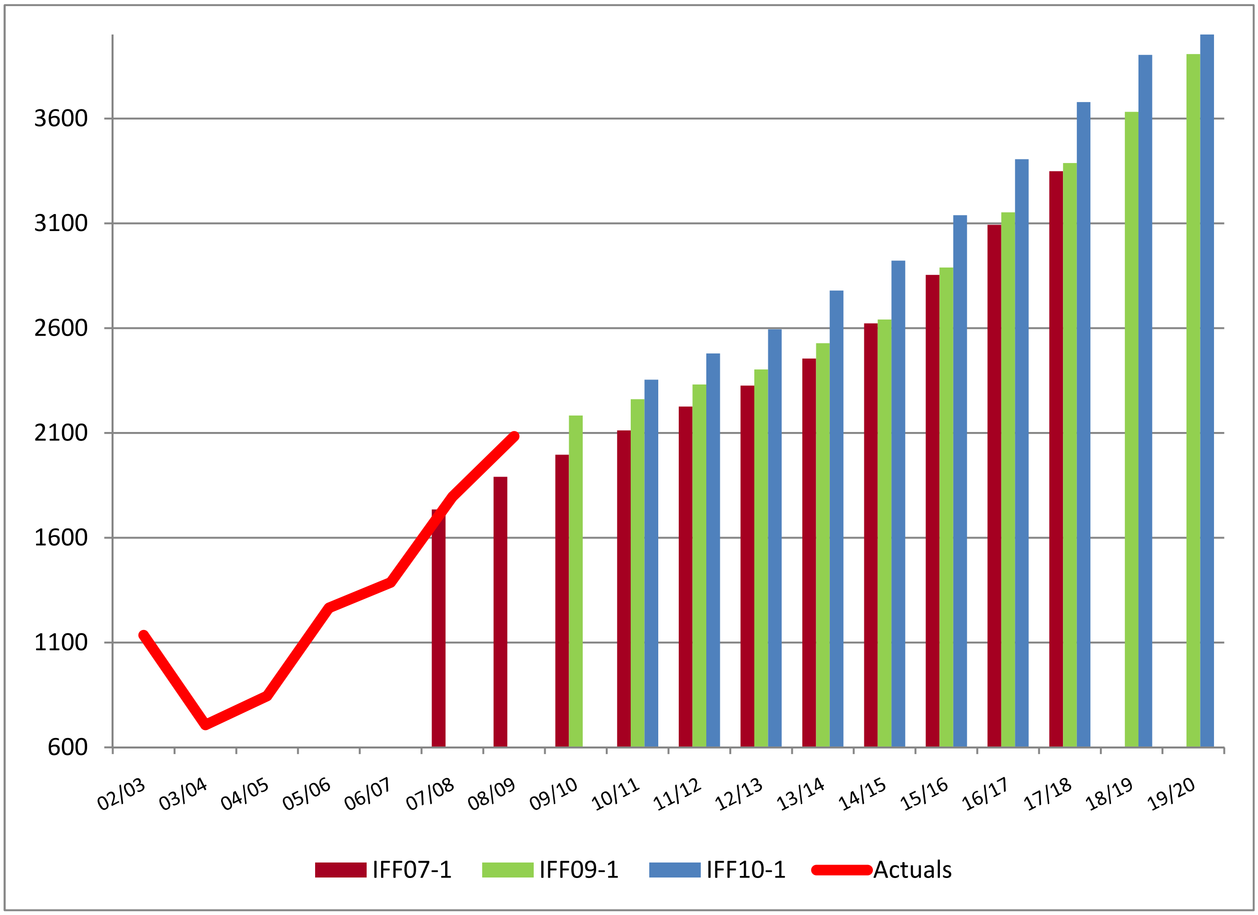
B.1: Retained Earnings

Figure B.1-2 compares actual electric operations retained earnings and forecasts from IFF07-1, IFF09-1 and IFF10. A review of Figure B.1-2 indicates that 2007/08 retained earnings were approximately the same as the IFF07-1 forecast ($1,795 million in actual compared to $1,735 million in IFF07-1) and improved further in 2008/09 to $2.084 billion relative to IFF07-1 forecasts of $1.891 billion.

Retained earnings forecasts for the years 2009/10 through 2017/18 are higher for IFF09-1 and IFF10 compared to IFF07-1. Retained earnings forecasts by 2017/18 were $3.349 billion in IFF07-1 and are now $3.388 billion in IFF09-1 and $3.679 billion in IFF10 (nearly 10 per cent higher than IFF07-1). In short, the more recent forecasts show the absolute level of retained earnings is increasing during the period when the debt to equity ratio is eroding relative to previous forecasts.

[153] Tab 5 of 2010/12 GRA– Integrated Financial Forecast, pages 2-3.

Figure B.1-2
Comparison of Electricity Operation Retained Earnings ($ millions)[154]



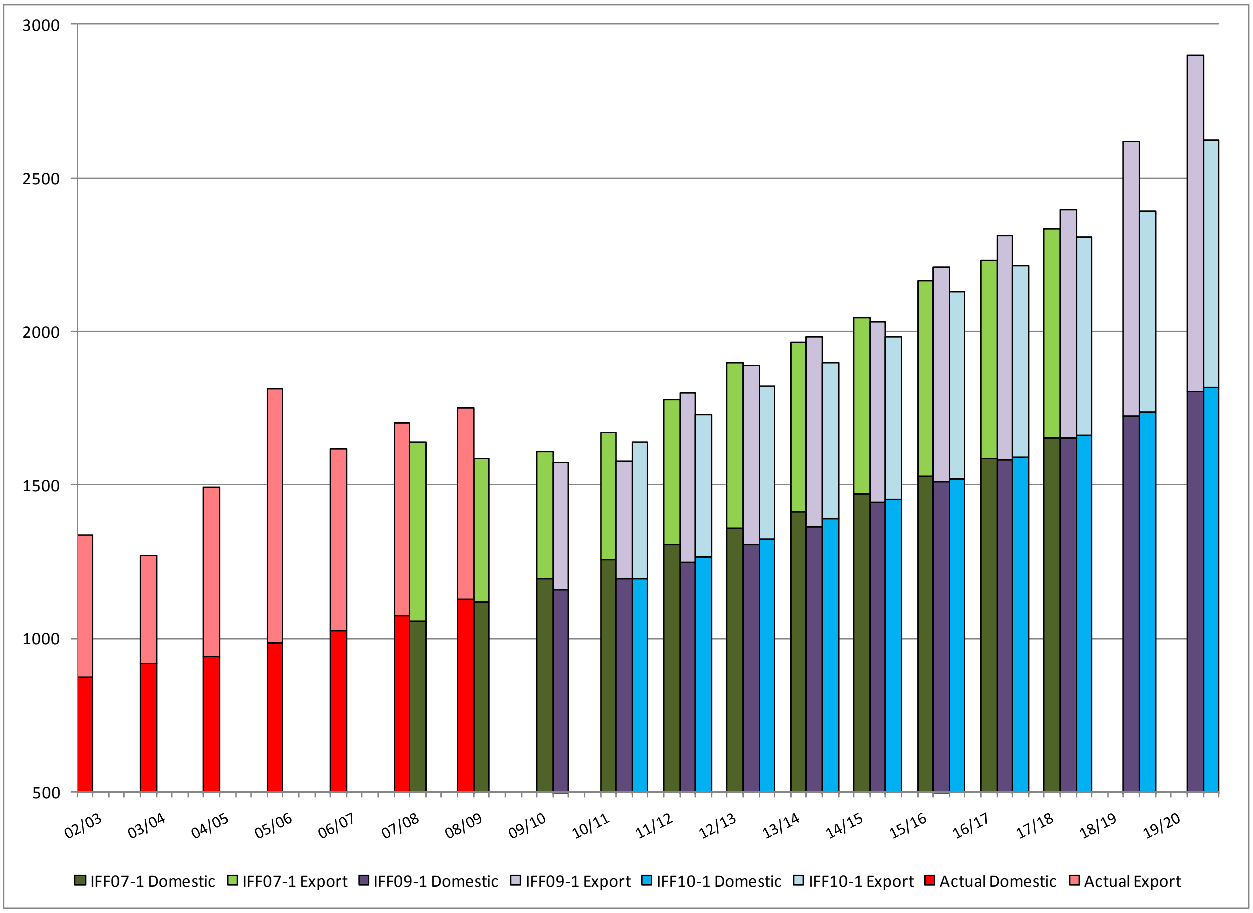
B-2: Total Electric Revenues

In assessing the situation with respect to overall revenues, Figure B.2-1 compares actual electricity revenues (domestic and exports) to forecast revenues in IFF07-1, IFF09-1 and IFF10. A review of Figure B.2-1 indicates that IFF10 now projects a substantial decline in electricity revenues compared to previous forecasts. In particular Hydro notes in IFF09-1 that projected load growth in the general service class is lower by more than 10,000 GW.h over the period to 2018/19[155]. Hydro attributes this decline to overall lower projected consumption in the primary metals and chemical sectors as a result of the economic downturn.

[154] Data for 2002/03 actual Electric Retained Earnings from 2008 GRA Coalition/MH II-18a; 2004-09 actual Electric Retained Earnings as per PUB/MH I-1 (Revised) from the 2010/12 GRA. IFF07-1 data from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Electric Operations (MH07-1) Projected Balance Sheet (p.39). IFF09-1 data from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Electric Operations (MH09-1) Projected Balance Sheet (p.35). IFF10-1 data from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Electric Operations (MH10) Projected Balance Sheet (p. 34).

[155] IFF09-1, page 6.

Figure B.2-1
Comparison of Electricity Operation Revenues ($ millions)[156]

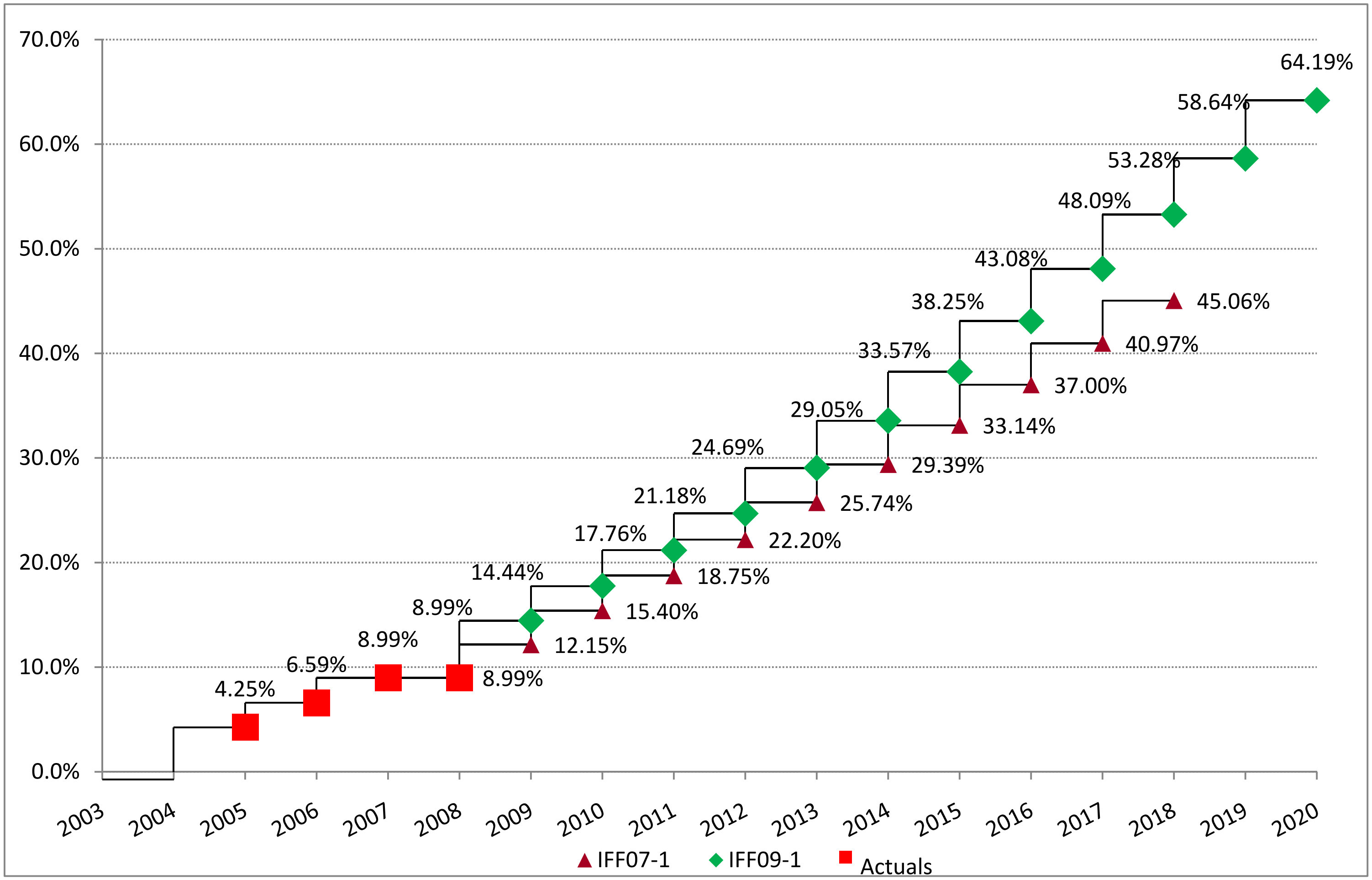


[156] Domestic Revenues calculated as (general revenues at approved rates + general revenues at additional rates). 2002/03-2003/04 actual Electric Revenues as per Coalition/MH II-18(a) from the 2008 GRA. 2004/05-2008/09 actual Electric Export Revenues as per PUB/MH I-27 from the 2010/12 GRA. 2004/05-2008/09 Actual Domestic Electric Revenues as per PUB/MH I-1a (revised) from 2010/12 GRA.IFF07-1 Electric Revenue from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Electric Operations (MH07-1) Projected Operating Statement (p.38). IFF09-1 Electric Revenue from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Electric Operations (MH09-1) Projected Operating Statement (p.34). IFF10-1 Electric Revenue from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Electric Operations (MH10) Projected Operating Statement (p. 33).

Figure B.2-2 shows the cumulative rate increases for domestic rates assumed in IFF07-1 and actuals plus increases assumed in IFF09-1. Figure B.2-2 includes the slight decrease awarded to GSL and GSS customers in 2003, followed by the subsequent actual rate increases. Overall, Figure B.2-2 shows that, basically throughout the period in question, the cumulative rate increases in IFF09-1 are higher than assumed at the time of IFF07-1.

Figure B.2-2

Electricity Operation Cumulative Rate Increase[157]

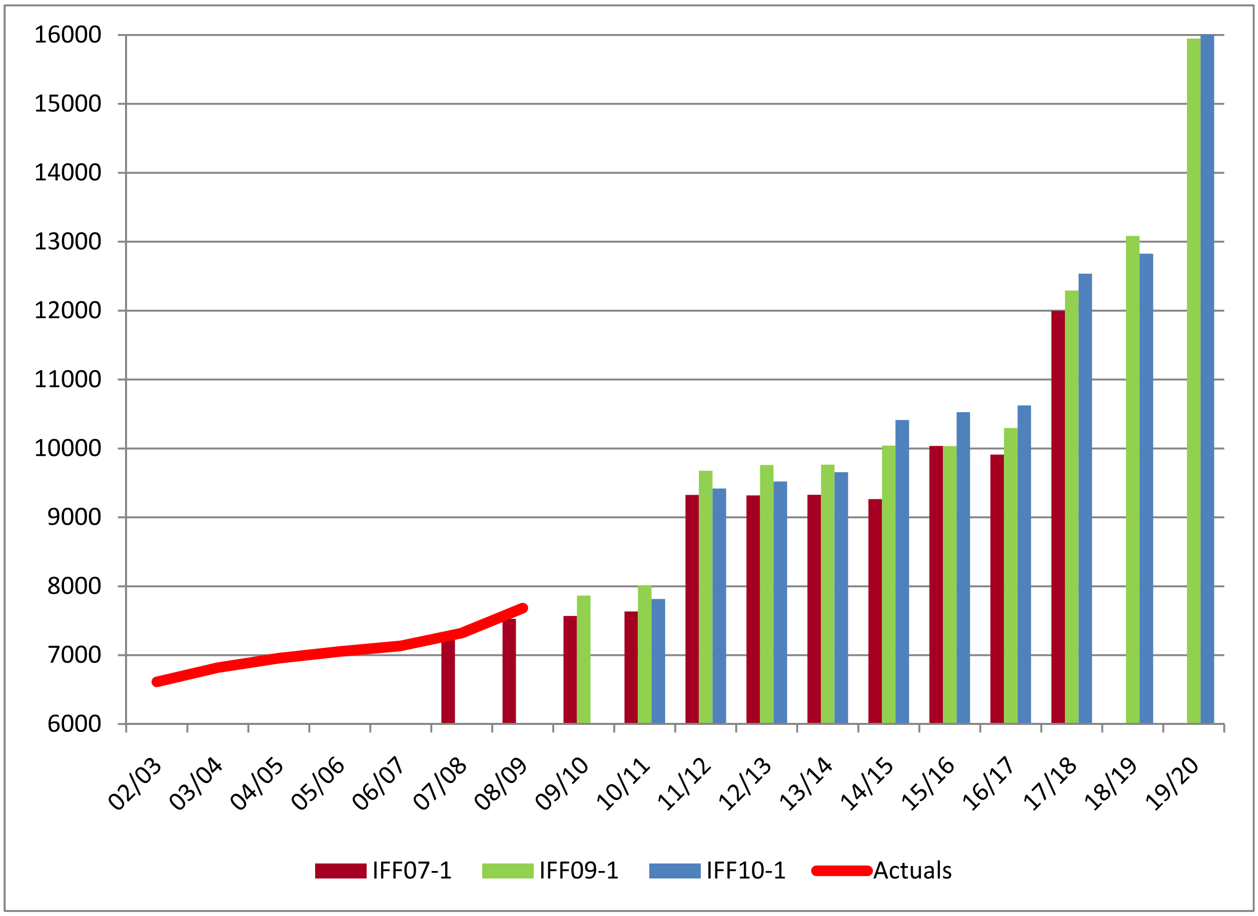


[157] Rate decrease in 2003/04 is estimated based on $6.454 million shown in the response to CAC/MSOS/MH I – 54 from the 2004 GRA divided by electricity general consumer revenues of $901 million in 2003/04 shown in IFF03-1Electric Operations Projected Operating Statement (pg. 32). Actuals also reflect the 5% increase effective August 1, 2004; the 2.25% rate increase effective April 1, 2005, the 2.25% rate increase effective March 1, 2007, the 5% increase effective July 1, 2008, the 2.9% increase effective April 1, 2009 and the 2.9% interim increase effective April 1, 2010.

B.3: Net Plant in Service

Figure B.3-1 compares the net plant in service on an actual basis and forecasts in IFF07-1, IFF09-1 and IFF10. A review of Figure B.3-1 shows that net plant in service was higher on an actual basis in 2007/08 to 2008/09 than forecast in IFF07-1. IFF09-1 and IFF10 forecasts are also higher than IFF07-1 forecasts.

Figure B.3-1
Comparison of Electricity Net Plant in Service ($ millions)[158]



The increase in net plant-in-service is undoubtedly a key driver in the changes to the forecast debt:equity ratios. Due to the nature of the accounting cost profile of capital spending, the impact of this higher level of capital expenditures will have increasing cumulative impacts on the level of net income in the future.

[158] Data for 2002/03-2003/04 actual Electric Net Plant in Service from 2008 GRA Coalition/MH II-18(a). 2004/05-2008/09 data for actual Electric Net plant in Service as per PUB/MH I-27. IFF07-1 data from Manitoba Hydro IFF07-1 Appendix 22 to the 2008 GRA Electric Operations (MH07-1) Projected Balance Sheet (p.39). IFF09-1 data from Manitoba Hydro IFF09-1 Appendix 5.2 to the 2010/12 GRA Electric Operations (MH09-1) Projected Balance Sheet (p.35). IFF10-1 data from Manitoba Hydro IFF10-1 Appendix 76 to the 2010/12 GRA Electric Operations (MH10) Projected Balance Sheet (p. 34).

B.4: Operations, Maintenance & Administration Expense

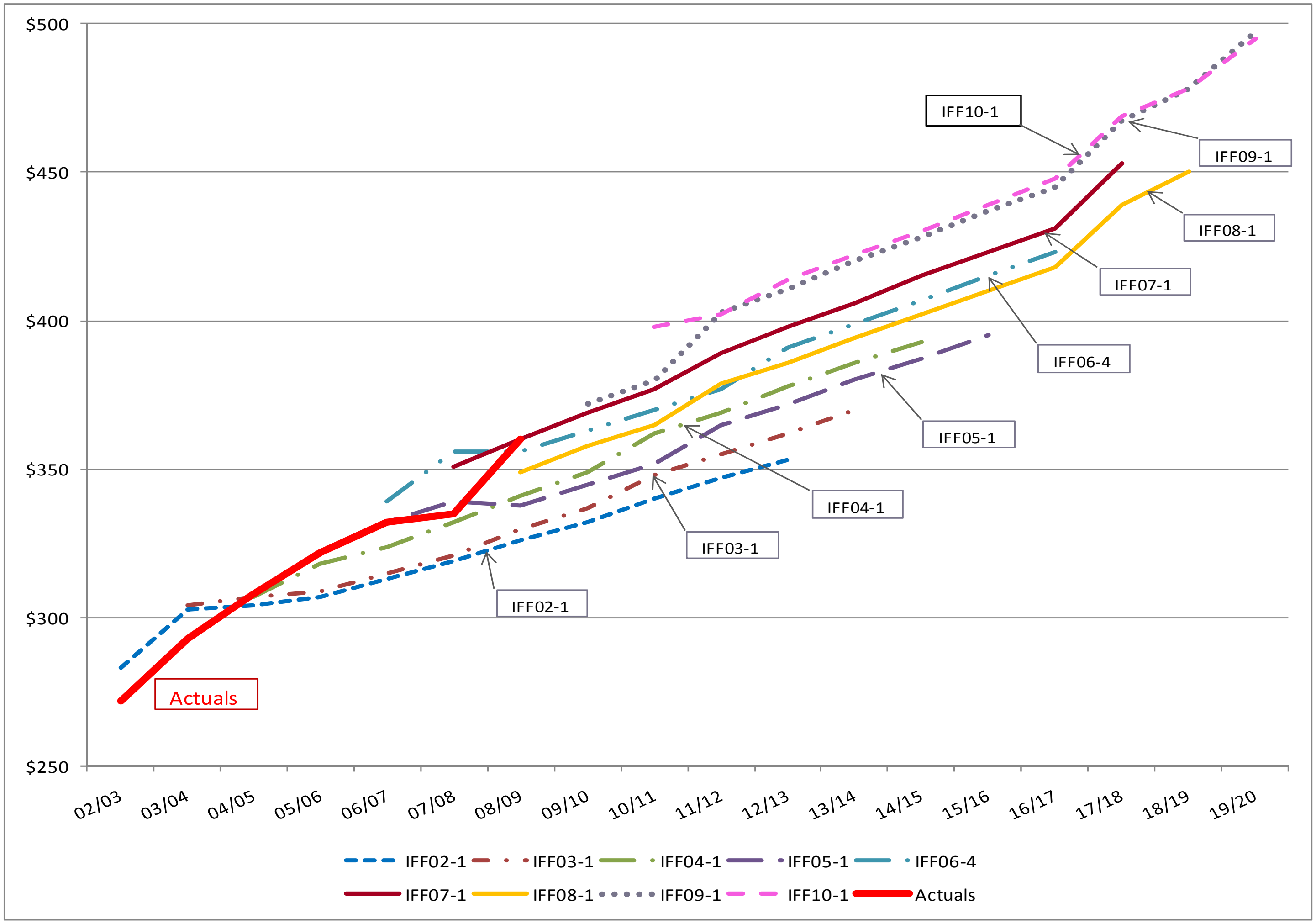
Figure B.4-1 compares Hydro's Operations, Maintenance & Administration Expense ("OM&A") by year for recent IFFs and actuals through 2008/09. A review of Figure B.4-1 indicates that Hydro's OM&A forecasts have generally trended higher for each IFF, with IFF09-1 and IFF10 being the highest of the group.

It is noted that certain limited categories of costs have been shifted by Hydro as to how they are classified in the various IFFs (i.e., items previously included in electric operations OM&A now excluded, or vice versa). Material changes in categorization that have been identified include: (a) the exclusion of the annual OM&A costs of subsidiaries starting in IFF08-1 that were previously included in Electric Operations OM&A (approximately $16 million in 2011/12)[159], (b) the addition of annual IFRS related impacts of $15 million first included in IFF09-1 (apparently largely related to items historically that were historically capitalized as overheads - $15 million per year starting in 2011/12), and the addition of costs historically recorded as deferred of approximately $11 million per year starting IFF09-1 (for the 2009/10 year). These effects are largely offsetting. No adjustment has been made to Hydro's IFF data in the preparation of Figure B.4-1.

[159] CAC/MSOS/MH I-14(b).

1 **Figure B.4-1[160]**

2 **Comparison of Electricity Operations, Maintenance & Administration Expense ($ millions)**



3

[160] Forecasts taken from each of the referenced IFFs, Projected Operating Statements. Forecast OM&A electric expense from IFF02-1 to IFF07-1 includes the OM&A expense for electric subsidiaries. Forecast OM&A expense for IFF08-1 to 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 data as per CAC/MSOS/MH I-128 from the 2010/12 GRA and does not include the electric subsidiary portion of OM&A.

ATTACHMENT C – COST OF SERVICE RESULTS SINCE 1992

Once an overall level of revenues to be recovered from domestic customers is determined, the relative cost responsibility of each customer class is determined based on principles of "cost-of-service". Manitoba Hydro uses a Cost-of-Service Study ("COSS") as a method for determining a fair allocation of its costs to the customers it serves based primarily on principles of cost causation. For more than a decade, Manitoba Hydro's COSS consistently indicated that certain customer classes were paying well above the fair costs to serve their loads while other customer classes paid rates that were not sufficient to recover a fair apportionment of their costs.

In its Order following the 2004 GRA, the Board indicated its concern that the COSS was in a state of flux and in the Board's view, incomplete. As such, the Board could no longer rely on the COSS results for assessing the revenue to cost coverage ratios. The Board directed Hydro to file three separate COSS models, as well as studies that considered the merits and rate impacts of allocating less expensive generation costs to domestic classes with higher generation costs being allocated to domestic and export customers. Hydro was also directed to file a report on the utilization of the Zone of Reasonableness ("ZOR") concept where all customers are moved to unity within five to seven years[161].

In response to the Board's directive, and following the filing of a General Rate Application that it subsequently withdrew, Hydro filed an application in November 2005 for a revised COSS. The Board heard evidence from Hydro and three intervenors during a hearing process that lasted 11 days in May and June 2006[162]. Following the proceeding, the Board issued Order 117/06, which summarized its views and findings with respect to Hydro's COSS. The total cost to Hydro of the proceeding was approximately $1.282 million[163].

The Board subsequently reviewed Manitoba Hydro's cost-of-service methods as part of the 2008 GRA. The Board's Order in that proceeding directed Hydro to make certain other methodological changes to the COSS. Manitoba Hydro's PCOSS10 and PCOSS11 implement many, but not all, of the Board's directives, as reviewed in Section 4.

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[161] Refer to pages 96 and 97 of Order 143/04.

[162] As summarized in Board Order 117/06, page 6.

[163] MIPUG/MH II-3 (g). It should be noted that this excludes costs incurred by intervenors who did not apply for cost recovery, including MIPUG.

REVENUE TO COST COVERAGE RATIOS

The cost of service studies produced for each Hydro rate review calculate the revenue to cost coverage ratio for each customer class and subclass. The RCC is essentially a measure of the degree to which the rates charged to a customer class fairly reflect the net costs that the customer class imposes on Hydro's system. In Hydro's current COSS, costs are defined to include all revenues required by Hydro, including required contributions to Hydro's reserves.

It has been the Board's long standing practice to use Revenue to Cost ratios ("RCC"s) as a benchmark for evaluating rate proposals for different customer classes. For example, a RCC ratio of 1.00 or 100% illustrates rates that are equal to the calculated costs. A RCC ratio greater than 1.0 indicates that the revenues from a class are above the calculated costs to serve that class. In order to evaluate Hydro's rate proposals, the Board has established a Zone of Reasonableness ("ZOR") as a target level for assessing the RCC's and consequently the level of rates charged to each class.

The PUB and Hydro have each recognized that RCCs should not vary from 100% to any marked degree (e.g., within a 'Zone of Reasonableness' of 95% to 105%) and that there is no basis to maintain a customer class RCC at above or below 100% on a consistent basis. The PUB used a Zone of Reasonableness prior to 1996 that equalled 90% to 110%, and revised this range to 95% to 105% in Order 51/96[164].

In each year, the RCC ratio can change for a number of reasons:

- **Changes in the relative level of rates:** This can include rate increases or decreases. Since July 2008 the Board has approved cumulative across-the-board rate increases of approximately 11% (including the interim April 1, 2010, increase related to the current GRA. These rate increases are included in customer class revenues reported in PCOSS11).

- **Changes in the utility costs and the variables that are used to allocate costs:** This includes such variables as the system peak and total energy sales that are used to assign certain types of costs in the cost of service study.

[164] In Decision 51/96 the Board directed Hydro to undertake a study prior to the next GRA to address alternatives for solving the persistent problem of some rate sub-classes (specifically Residential Zone 3 and General Service Large >100kv) being persistently outside the Zone of Reasonableness. The Board also indicated that this study should assume a revised ZOR target of 95%-105%. See page 41 of Board Order 51/96.

- **Changes in the cost of service methodology:** Changes to Manitoba Hydro's cost of service study include certain revisions approved by the Board in its Orders and recommended by Manitoba Hydro.

Table C-1 reviews the RCC ratios from 1991/92 to 2010/11. The table shows a material variance in RCC ratios from 100% for many customer classes. Industrial customers (class GS Large >100kV in particular) have consistently had a RCC well above the zone of reasonableness defined by the Board. For 2010/11, the cost of service methodology continues to show this variance.

Table C-1
Revenue Cost Coverage Ratios 1991/92 to 2010/11[165]

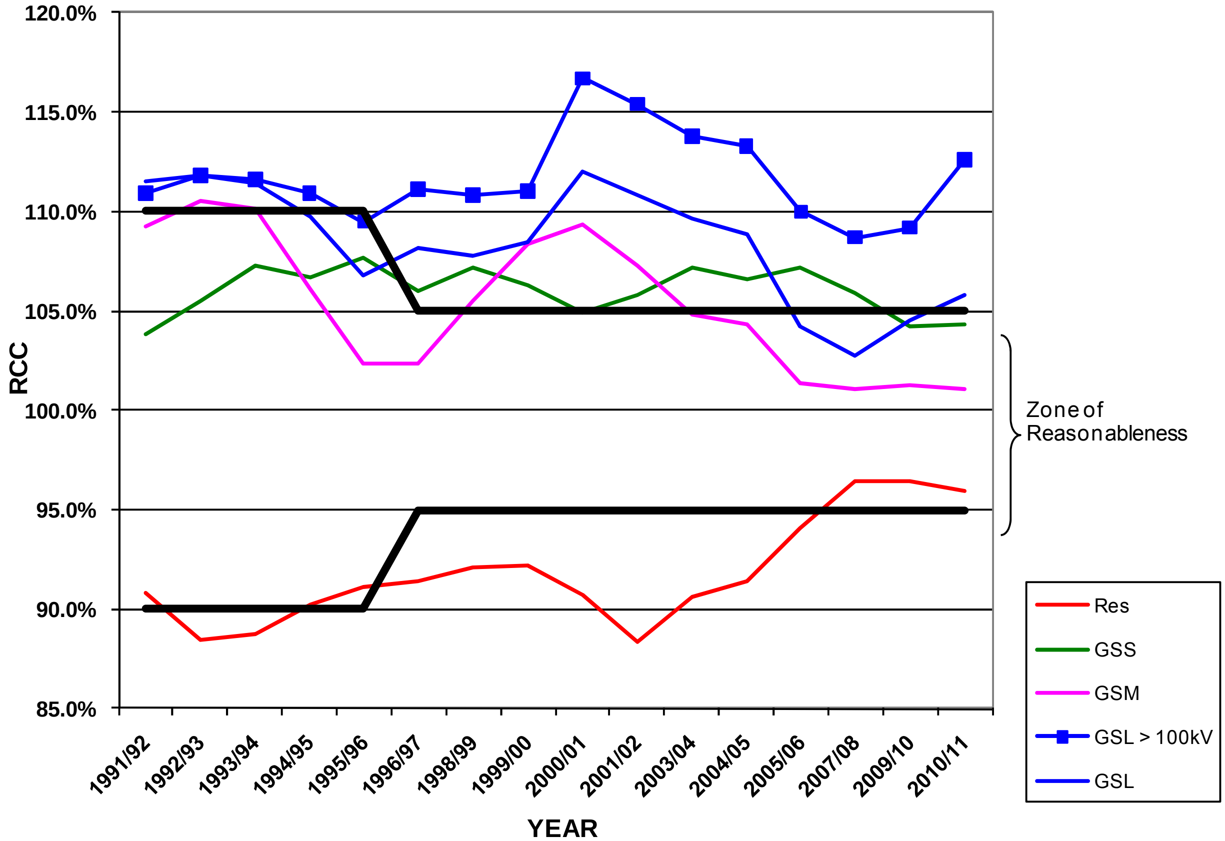
PCOSS	91/92	92/93	93/94	94/95	95/96	96/97	98/99	99/00
Res	90.8%	88.5%	88.7%	90.2%	91.1%	91.4%	92.1%	92.2%
GSSmall	103.8%	105.5%	107.3%	106.7%	107.7%	106.0%	107.2%	106.3%
GSMed	109.3%	110.5%	110.1%	106.1%	102.4%	102.4%	105.5%	108.4%
GSL<30kv	109.0%	109.7%	109.5%	105.2%	98.5%	100.9%	101.4%	101.2%
GSL30-100kv	122.5%	117.5%	114.8%	111.8%	109.4%	108.1%	110.3%	112.0%
GSL>100kv	110.9%	111.8%	111.6%	110.9%	109.5%	111.1%	110.8%	111.0%
GSCurtail							107.5%	110.3%
Lighting	118.7%	119.0%	117.0%	119.6%	112.5%	108.8%	93.4%	95.3%

PCOSS	00/01	01/02	03/04	04/05	05/06	07/08	09/10	10/11
Res	90.7%	88.4%	90.6%	91.4%	94.1%	96.4%	96.4%	95.9%
GSSmall	104.9%	105.8%	107.2%	106.6%	107.2%	105.9%	104.2%	104.3%
GSMed	109.4%	107.3%	104.8%	104.3%	101.4%	101.1%	101.3%	101.1%
GSL<30kv	102.6%	99.9%	99.9%	100.3%	91.3%	90.4%	92.3%	91.9%
GSL30-100kv	118.8%	118.5%	109.5%	108.6%	104.7%	103.7%	106.8%	104.2%
GSL>100kv	116.7%	115.4%	113.8%	113.3%	110.0%	108.7%	109.2%	112.6%
GSCurtail	114.5%	111.3%	114.6%	112.6%				
Lighting	92.0%	97.6%	108.9%	109.8%	107.7%	105.8%	100%	105.2%

This information is presented graphically in Figure C-1, which also indicates the ZOR as determined by the Board for the respective year.

[165] Data for 1991/92-1996/97 from MIPUG/MH/CR-2(b) from the 1996/97 GRA. 1998/99-2001/02 data from MIPUG/MH I-30 (a) from 2002 Status Update filing. 2001/02 data represents the previous PCOSS methodology as stated in MIPUG/MH I-30 (a) from 2002 Status Update Filing. No PCOSS was available for 1997/98 or 2002/03. 2003/04 data from MIPUG/MH I-21a from 2003/04 GRA. 2004/05 data from MIPUB/MH I-21(f) from 2003/04 GRA. 2005/06 data was taken from Hydro's 117/06 Directed Amendments to PCOSS06 (Appendix 39 to 2008 GRA). 2007/08 data was taken from PCOSS08. 2009/10 data from PCOSS10. 2010/11 data from PCOSS11. 2005/06 – 2010/11 GSL>100kv including curtailment customers. A PCOSS for 2006/07 and 2008/09 was not reviewed for this analysis.

Figure C-1
Revenue Cost Coverage Ratios as Reported by Hydro 1991/92 to 2010/11



1. 1991/92-1996/97 data from MIPUG/MH/CR - 2 (b) from the 1996/97 GRA.
2. 1998/99-2001/02 approved data from MIPUG/MH I - 30 (a) from the 2001/02 GRA.
3. 2002/03-2003/04 data from PUB/MH I-28 (c) from the 2003/04 GRA.
4. 2004/05 data from MIPUG/MH I-21(f) from the 2003/04 GRA.
5. 2005/06 data from MH revised PCOSS06 per Order 117/06. GSL>100kv includes the curtailment customers.
6. 2007/08 data from PCOSS08.
7. No Cost of Service Study was reviewed for 1997/98, 2002/03 or 2008/09.

A review of Table C-1 and Figure C-1 indicate that certain rate classes have remained persistently outside the ZOR target of 95%-105%.

Calculation of Bulk Power Costs

For the cost of service analysis summarized in Table 5.1, it was desirable to be able to show costs by function after the creation of an export class but before net export revenue allocations. To derive this information, the following steps were undertaken:

Table C-2
Functionalization and Classification (Net of Export Revenues)

		Total Costs	Energy Related	Demand Related	Customer Related
1	**Generation Costs**	$922,121	$910,455	$0	$11,666
2	Allocated	$718,569	$718,569		
3	Direct	$203,552	$191,886	$0	$11,666
4	**Transmission Costs**	$193,675	$0	$193,675	$0
5	Allocated	$191,597		$191,597	
6	Direct	$2,078	$0	$2,078	
7	**Subtransmission Costs**	$75,258	$0	$75,258	$0
8	Allocated	$75,258		$75,258	
9	Direct	$0			
10	**Distribution Costs**	$310,744	$0	$219,615	$91,129
11	Allocated	$297,203		$219,615	$77,588
12	Direct	$13,541			$13,541
13	**Customer Service Costs**	$97,296	$0	$0	$97,296
14	Allocated	$97,296			$97,296
15	Direct	$0			
16	**Total Costs**	**$1,599,094**	**$910,455**	**$488,548**	**$200,091**

Table C-2 shows allocated and directly assigned costs by function (generation, transmission, subtransmission, distribution and customer service). Allocated costs at rows 2, 5, 8, 11 and 14 are taken from Schedule E1 of PCOSS11. Schedule E1 also identifies the allocation table used to allocate each type of cost. Direct costs are taken from page 2 of Schedule E1 in the PCOSS11.

Table C-3
Generation and Transmission Cost Allocation Split

		Domestic	Domestic & Export
1	Generation Costs	*$75,579*	*$642,990*
2	Energy Related	(E13)	(E12)
3	Transmission Costs	*$3,677*	*$187,920*
4	Demand Related	(D13)	(D14)

Table C-3 shows the split between allocation tables E12; E13; D13 and D14 for generation and transmission costs as summarized in Schedule E1 of PCOSS11.

Table C-4
Cost Allocators

		E12	E13	D13	D14	D21 - D23	D32,36	D40	C10	C11	C12	C13	C14	C15	C23	C27
1	Residential	26.74%	33.69%	35.02%	26.75%	51.49%	53.49%	57.90%	41.49%	83.62%	74.50%	85.07%	45.21%	88.99%	86.30%	75.64%
2	GSS - ND	6.18%	7.79%	8.61%	6.58%	10.07%	10.43%	11.29%	18.97%	11.82%	20.19%	9.62%	43.55%	8.05%	9.76%	15.95%
3	GSS - D	7.30%	9.19%	9.51%	7.26%	11.09%	11.52%	12.47%	4.12%	2.78%	4.46%	2.09%	9.45%	1.92%	2.12%	6.67%
4	GSM	11.58%	14.60%	15.07%	11.51%	15.54%	16.14%	17.48%	13.99%	0.50%	0.73%	0.34%	1.54%	0.89%	0.35%	1.51%
5	GSL 0-30kV	5.81%	7.32%	7.50%	5.73%	7.35%	7.63%	0.00%	8.05%	0.15%	0.02%	0.05%	0.21%	0.12%	0.05%	0.21%
6	GSL 30-100kV	2.99%	3.77%	3.48%	2.66%	3.69%	0.00%	0.00%	5.87%	0.02%	0.00%	0.01%	0.02%	0.01%	0.00%	0.00%
7	GSL over 100kV	18.44%	23.24%	20.52%	15.67%	0.00%	0.00%	0.00%	6.16%	0.01%	0.00%	0.00%	0.01%	0.01%	0.00%	0.00%
8	Lighting	0.32%	0.41%	0.28%	0.22%	0.77%	0.80%	0.86%	0.70%	1.10%	0.09%	2.82%	0.00%	0.00%	1.43%	0.00%
9	SEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.65%	0.00%	0.01%	0.00%	0.01%	0.01%	0.00%	0.02%
10	**Total - General Customers**	79.37%	100.00%	100.00%	76.37%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Diesel	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%	0.00%
12	Extra Provincial	20.63%	0.00%	0.00%	23.63%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Integrated System**	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Table C-4 provides cost allocators by customer class based on the allocation tables shown in the PCOSS11 Allocation Program. Allocation percentages were calculated based on the total value for each class of customer divided by the total system amount for each allocation table[166].

[166] Allocation tables used can be found from Appendix 59:PCOSS11 Allocation Program pages 6-9, and 11-16.

Table C-5
Allocated Costs by Customer Class

	Generation			Transmission			Sub-Transmission	Distribution		Customer	Total Costs			
	Energy (E12)	Energy (E13)	Customer	Energy	Demand (D13)	Demand (D14)	Demand (D21 - D23)	Demand	Customer	Customer	Bulk Power Costs	Sub-transmission Costs	Distribution and Customer Costs	Total Costs
1 Residential	$171,922	$25,460			$1,288	$50,264	$38,753	$118,962	$63,304	$63,026	$248,934	$38,753	$245,292	$532,979
2 GSS - ND	$39,746	$5,886			$317	$12,358	$7,582	$23,193	$8,132	$16,543	$58,307	$7,582	$47,868	$113,756
3 GSS - D	$46,924	$6,949			$350	$13,650	$8,344	$25,614	$3,950	$3,678	$67,874	$8,344	$33,241	$109,459
4 GSM	$74,485	$11,031			$554	$21,631	$11,696	$35,903	$951	$5,628	$107,700	$11,696	$42,482	$161,879
5 GSL 0-30kV	$37,376	$5,535			$276	$10,761	$5,530	$14,170	$216	$3,064	$53,948	$5,530	$17,449	$76,927
6 GSL 30-100kV	$19,221	$2,846			$128	$4,997	$2,776	$0	$46	$2,196	$27,192	$2,776	$2,242	$32,211
7 GSL over 100kV	$118,593	$17,563			$754	$29,445	$0	$0	$22	$2,298	$166,355	$0	$2,320	$168,675
8 Lighting	$2,084	$308			$10	$408	$578	$1,773	$955	$617	$2,811	$578	$3,345	$6,733
9 SEP	$0	$0			$0	$0	$0	$0	$13	$246	$0	$0	$259	$259
10 **Total - General Customers**	**$510,349**	**$75,579**			**$3,677**	**$143,515**	**$75,258**	**$219,615**	**$77,589**	**$97,296**	**$733,120**	**$75,258**	**$394,500**	**$1,202,878**
11 Diesel	$0	$0			$0	$0					$0	$0	$0	$0
12 Extra Provincial	$132,641	$0			$0	$44,405					$177,046	$0	$0	$177,046
13 **Integrated System**	**$642,990**	**$75,579**			**$3,677**	**$187,920**	**$75,258**	**$219,615**	**$77,589**	**$97,296**	**$910,166**	**$75,258**	**$394,500**	**$1,379,924**

The allocation ratios calculated in Table C-4 are used to distribute the functionalized allocated costs from Table C-2 and C-3 between rate classes. Table C-5 shows the allocated costs by customer class.

Table C-6
Directly-Assigned Costs by Customer Class

	Generation			Transmission			Sub-Transmission	Distribution		Customer	Total Costs			
	Energy	Energy	Customer (C02)	Energy	Demand	Demand		Demand	Customer (C01)		Bulk Power Costs	Sub-transmission Costs	Distribution and Customer Costs	Total Costs
1 Residential	$7,386										$7,386	$0	$0	$7,386
2 GSS - ND	$4,882										$4,882	$0	$0	$4,882
3 GSS - D	$5,518										$5,518	$0	$0	$5,518
4 GSM	$6,573										$6,573	$0	$0	$6,573
5 GSL 0-30kV	$3,277										$3,277	$0	$0	$3,277
6 GSL 30-100kV	$704										$704	$0	$0	$704
7 GSL over 100kV	$4,666										$4,666	$0	$0	$4,666
8 Lighting	$9								$12,832		$9	$0	$12,832	$12,841
9 SEP	$587					$159					$587	$159	$0	$746
10 **Total - General Customers**	**$33,602**	**$0**				**$159**			**$12,832**		**$33,602**	**$159**	**$12,832**	**$46,593**
11 Diesel			$11,666						$709		$0	$0	$12,375	$12,375
12 Extra Provincial	$158,284					$1,919					$158,284	$1,919	$0	$160,203
13 **Integrated System**	**$191,886**	**$0**	**$11,666**	**$0**		**$2,078**			**$13,541**		**$191,886**	**$2,078**	**$25,207**	**$219,171**

Table C-6 shows directly assigned costs by customer class and function as found on page 2 of Schedule E1 of PCOSS11.

Table C-7
Total Costs by Customer Class

	Generation			Transmission			Sub-Transmission	Distribution		Customer	Total Costs			
	Energy (E12)	Energy (E13)	Customer	Energy	Demand (D13)	Demand (D14)	Demand (D21 - D23)	Demand	Customer	Customer	Bulk Power Costs	Sub-transmission Costs	Distribution and Customer Costs	Total Costs
1 Residential	$179,308	$25,460	$0	$0	$1,288	$50,264	$38,753	$118,962	$63,304	$63,026	$256,320	$38,753	$245,292	$540,365
2 GSS - ND	$44,628	$5,886	$0	$0	$317	$12,358	$7,582	$23,193	$8,132	$16,543	$63,189	$7,582	$47,868	$118,638
3 GSS - D	$52,442	$6,949	$0	$0	$350	$13,650	$8,344	$25,614	$3,950	$3,678	$73,392	$8,344	$33,241	$114,977
4 GSM	$81,058	$11,031	$0	$0	$554	$21,631	$11,696	$35,903	$951	$5,628	$114,273	$11,696	$42,482	$168,452
5 GSL 0-30kV	$40,653	$5,535	$0	$0	$276	$10,761	$5,530	$14,170	$216	$3,064	$57,225	$5,530	$17,449	$80,204
6 GSL 30-100kV	$19,925	$2,846	$0	$0	$128	$4,997	$2,776	$0	$46	$2,196	$27,896	$2,776	$2,242	$32,915
7 GSL over 100kV	$123,259	$17,563	$0	$0	$754	$29,445	$0	$0	$22	$2,298	$171,021	$0	$2,320	$173,341
8 Lighting	$2,093	$308	$0	$0	$10	$408	$578	$1,773	$13,787	$617	$2,820	$578	$16,177	$19,574
9 SEP	$587	$0	$0	$0	$0	$159	$0	$0	$13	$246	$746	$0	$259	$1,005
10 **Total - General Customers**	**$543,951**	**$75,579**	**$0**	**$0**	**$3,677**	**$143,674**	**$75,258**	**$219,615**	**$90,421**	**$97,296**	**$766,881**	**$75,258**	**$407,332**	**$1,249,471**
11 Diesel	$0	$0	$11,666	$0	$0	$0	$0	$0	$709	$0	$0	$0	$12,375	$12,375
12 Extra Provincial	$290,925	$0		$0	$0	$46,324	$0	$0	$0	$0	$337,249	$0	$0	$337,249
13 **Integrated System**	**$834,876**	**$75,579**	**$11,666**	**$0**	**$3,677**	**$189,998**	**$75,258**	**$219,615**	**$91,130**	**$97,296**	**$1,104,130**	**$75,258**	**$419,707**	**$1,599,095**

Table C-7 sums Table C-5 and Table C-6 (allocated and direct costs) to produce the total costs by customer class. The total costs column matches the Total Costs column from Schedule B1 (Revenue Cost Coverage Analysis) of PCOSS11. The Bulk Power Costs on line 1 of Table 5.1 is the sum of generation and transmission costs[167]. The subtransmission costs are shown in line 2 of Table 5.2. The Distribution and Customer cost columns are shown in line 3 of Table 5.1.

[167] For Extra Provincial the Bulk Power Cost sum from Table 5.1 is net of Uniform Rate Credit and Affordable Energy Funds Expenditure therefore it does not equal Line 1 of Table 5.1 Bulk Power Costs in Table 5.1 for Exports is calculated as follows: Bulk Power Costs from Table C-7 ($337.2 million) subtract Uniform Rate Credit ($20.0 million) subtract Affordable Energy Fund Expenditures ($12.0 million).