MANITOBA PUBLIC UTILITIES BOARD

MANITOBA HYDRO
2019/20 RATE APPLICATION

Evidence Prepared By

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On Behalf of

Consumers' Association of Canada (Manitoba Branch)

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(The Consumers Coalition)

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1.0 Executive Summary

Manitoba Hydro (MH) is proposing that the PUB approve a 3.5% rate increase for 2019/20 on a final basis.

The purpose of this evidence is to independently evaluate MH's reasons for the proposed rate increase as well as the proposals with respect to cost of service and rate design and make rate-setting recommendations to the Public Utilities Board of Manitoba (PUB) for MH's 2019/20 fiscal year.

1.1. MH Continues to Propose a 3.5% Rate Increase Despite a $92 Million Improvement in the Financial Outlook for 2019/20

MH's original rate application projected a $28 million loss if there was no rate increase in 2019/20. The proposed 3.5% rate increase was expected to generate a modest net income of $31 million for 2019/20

There has been a $92 million improvement in the updated projected financial results for 2019/20 in comparison to the original rate application, which improves the projected net income without a rate increase from a loss of $28 million to a profit of $64 million.

Despite this significant improvement, the central theme of the MH application is that the proposed 3.5% rate increase continues to allow MH to plan for a modest level of net income in the event of low water flow conditions or the occurrence of other negative financial events that are unpredictable and outside of MH's control and reduces the likelihood of future rate shock to ratepayers that could result from a financial loss in 2019/20.

1.2. The Unique Nature of MH's Rate Application Poses Significant Challenges in Evaluating MH's Rate Increase Proposal

The MH 2019/20 rate application is unique in many aspects. The most significant, is that there is no long-term financial plan and rate strategy for the PUB to use to guide rate-setting and MH's long-term financial forecast and financial plan is not in scope for review in the current regulatory proceeding. The recently appointed

MHEB is currently in the process of undertaking a comprehensive review of MH's strategy, operations, forecasts, financial plans and rate strategy which will form the basis of MH's next GRA.

The unique nature of the MH 2019/20 rate application and the more limited scope of the regulatory process poses significant challenges in terms of the appropriate rate-setting framework to use to evaluate the rate proposals. The PUB's rate-setting process inherently involves a complex review of a number of financial metrics including financial reserves, debt levels, and financial ratios such as equity, interest and capital coverage.

1.3. It is Not Possible for the PUB to Use the Modified Cost of Service Rate Setting Framework in the Absence of a Reliable Long-Term Financial Forecast

The modified cost of service rate-setting framework that has traditionally been used to set electricity rates in Manitoba is dependent on a long-term financial forecast to assess the longer-term financial and rate implications of current rate-setting decisions. However, it is not possible for the PUB to use the modified cost of service rate-setting framework to set rates for 2019/20 in the absence of a reliable and updated long-term financial forecast.

1.4. Order 59/18 Provides Comprehensive Guidance for Rate-Setting that Can be Used to Overcome the Challenges in Setting 2019/20 Rates

However, despite these challenges, there is recent and comprehensive guidance from the PUB with respect to setting electricity rates in Manitoba from the review of MH's 2017/18 & 2018/19 General Rate Application (GRA) that culminated in PUB Order 59/18.

The PUB found in Order 59/18 that the assessment of rate increases must consider the circumstances of MH's operations – major capital projects with large upfront capital costs, relatively low operating costs and very long useful lives. The PUB also found in Order 59/18, that it is critical that MH manage and reduce

its controllable costs (operating & administration, business operations capital and demand side management investments) in an era of major capital projects with the associated financial and rate pressures.

The PUB also articulated important guidance on how to address risk within the rate-setting process in Order 59/18:

1. Key risks such as interest rate risk and export price risk should be built into rates when these risks materialize and not through building up of retained earnings;
2. Drought risk should be managed through a combination of retained earnings and regulatory action when required to address emerging risks facing MH; and
3. The PUB is prepared to take regulatory action (rate increases) when emergent risks such as drought are actually facing MH, but will not set rate increases to increase retained earnings to meet every risk faced by MH in advance of the occurrence of those risks.

1.5. An Independent Evaluation Does Not Support the Proposed 3.5% Rate Increase in 2019/20

With the above noted context in mind, the independent analysis provided in this evidence followed a relatively sequential process to consider the need for and appropriate level of any rate change for 2019/20:

1. Assess forecasts of projected revenues and expenses and key financial metrics before any rate increase is considered;
2. Assess if MH has appropriately managed costs for those financial levers that are within its control in order to mitigate the need for rate increases from customers; and
3. Consider the balancing of the financial integrity and risks of the utility with the rate impacts on customers.

After using this sequential process and applying the rate-setting guidance from Order 59/18, the key findings and conclusions of the analysis presented in this evidence can be summarized as follows:

1. MH's updated projections do not support the need for a 3.5% rate increase in 2019/20 as the projected net income of $64 million (without the proposed rate increase) exceeds MH's original financial objective of a modest net income of $31 million in 2019/20;
2. The proposed 3.5% rate increase for 2019/20 has not been justified by any quantifiable financial objective (net income), financial metric (financial ratios) or downside risk sensitivity;
3. A 1.0% to 2.0% rate increase would be more than sufficient to minimize the risk of a financial loss while adhering to the PUB findings in Order 59/18 with respect to how risk should be addressed in rate-setting;
4. MH has not adequately responded to the PUB findings from Order 59/18 to reduce controllable costs in an era of major capital projects with the associated rate pressures and as such, a downward rate-setting adjustment of $22 million is proposed to the 2019/20 MH O&A target from $511 million to $489 million; and
5. There is no material deterioration in MH's financial position or three primary financial targets since the 2017/18 & 2018/29 MH GRA, even without the 2019/20 proposed rate increase.

1.6. There is a Continuum of Rate-Setting Options Available to the PUB for 2019/20 Ranging from No Rate Increase to 3.5% as proposed by MH

The following continuum of rate-setting options for 2019/20, was evaluated in the evidence:

1. Award **no rate increase for 2019/20 on a final basis**, recognizing that the updated projections for 2019/20 (without the proposed rate increase) result in a $64 million net income and that the 3.5% proposed rate increase cannot be justified by any quantifiable financial objective (net income) or financial metric (financial ratios);

2. Award a **1.0% to 2.0% rate increase for 2019/20 on a final basis**, recognizing that this level of a rate increase would be more than sufficient to protect against the risk of a financial loss in 2019/20, consistent with the PUB findings in Order 59/18 with respect to how risk should be addressed in rate-setting; and
3. Award the **full rate increase requested of 3.5% for 2019/20 on an interim basis**, recognizing the concern over the future potential rate volatility associated with the in-service of the Keeyask generating station but also recognizing that there is no reliable long-term forecast available to the PUB to award this rate increase on a final basis.

1.7. A 1.0% to 2.0% Rate Increase in 2019/20, would Balance the Financial Health of MH with Customer Interests in 2019/20

The overall conclusion based on the analysis is that a 1.0% to 2.0% rate increase in 2019/20 would balance the financial health of MH with customer interests, as this range of rate increases:

1. Is expected to generate net income of between $100 million and $115 million for MH in 2019/20, if MH is able to manage its O&A costs within a rate-setting target of $489 million;
2. Is expected to result in financial ratios that are consistent with or exceed those from the 2017/18 & 2018/19 GRA;
3. Protects against the risks of a financial loss in 2019/20 consistent with the PUB's findings in Order 59/18 on how key risks should be addressed for rate-setting purposes; and
4. Is still expected to generate a reasonably healthy net income of between $78 million and $93 million for MH in 2019/20, even in the event that MH is unable to manage its O&A costs within a rate-setting target of $489 million.

1.8. It is Recommended that the PUB Approve a 1.5% Rate Increase for MH in 2019/20

Considering that there is no rules-based or formulaic rate-setting framework that can be used to exactly specify a precise rate recommendation for MH, the 1.5% midpoint of the 1.0% to 2.0% range is recommended for 2019/20.

1.9. It is Recommended that Any Rate Increase Granted for 2019/20 should be on an Across-the-Board Basis with the Exception of the GSS Non-Demand Class

In Order 59/18, the PUB directed that rates be differentiated by class based on PCOSS18 to more closely align revenues by class with allocated costs and the assessment that a number of classes were outside of the Zone of Reasonableness.

While no Cost of Service Study has been prepared for the purposes of the 2019/20 rate application, Bipole III coming in service in 2018/19 represents a profound change in circumstances from PCOSS18. The key impacts of the in-service of Bipole III from a Cost of Service perspective is that it will move the Residential and General Service Large Revenue to Cost Ratios into the Zone of Reasonableness.

The evidence in this regulatory process supports an across-the-board rate increase for all customer classes with the exception of the GSS Non-Demand Class who has had a Revenue to Cost Ratio that remains persistently above the Zone of Reasonableness.

1.10. It is Recommended that Any Rate Increase for 2019/20 should be Applied on an Across-the-Board Basis to All Components of the Rate Structure

The overall recommendation with respect to MH's rate design proposals is that they are acceptable for the 2019/20 rate application and that any rate increase for 2019/20 should be applied on an across-the-board basis to all components of the rate.

However, it is also recommended that it would be appropriate for MH and the PUB to review ratemaking objectives and rate design at the next GRA given

there has not been a recent and meaningful review of this important aspect of setting rates.

1.11. It is Recommended that Robust Compliance and Directives Filings with Intervenor Participation should be an Integral Part of the Regulatory Process

It is recommended that robust compliance and directives filings with Intervenor participation should be an integral part of an effective and efficient regulatory process for the current proceeding and the next GRA.

2.0 Qualifications and Duties

2.1. Darren Rainkie – Statement of Qualifications & Duties

Mr. Rainkie received his Bachelor of Commerce (Honours with Distinction) from the University of Manitoba in 1988. He received his Chartered Professional Accountant (Chartered Accountant) designation in 1991 and his Chartered Business Valuator designation in 1993.

Mr. Rainkie is the principal of the consulting practice he established in 2017 which leverages his 30-years of experience in energy regulation, utility & financial management and financial advisory services. He specializes in electricity and natural gas energy regulation which is informed by his broad expertise in utility and financial management.

Prior to establishing his consulting practice, Mr. Rainkie was employed with Price Waterhouse, Chartered Accountants from 1988-1994, which included consulting as an accounting and finance advisor to the Manitoba Public Utilities Board (1990-1994). He then was employed with Centra Gas (Westcoast Energy) from 1994-1999, first as Senior Financial Analyst, and then as Senior Regulatory Coordinator. Mr. Rainkie was employed with Manitoba Hydro & Centra Gas from 1999-2017 in various senior leadership roles including Manager of the Regulatory Services Department, Corporate Treasurer, Corporate Controller, Acting President and Chief Executive Officer and Vice-President, Financial & Regulatory Affairs and Chief Financial Officer.

Throughout his career, Mr. Rainkie has gained significant experience in all aspects of energy regulation including policy, strategy, revenue requirement, cost of capital/capital structure, cost allocation, rate design and major project reviews, as well as the planning and management of numerous regulatory applications and associated hearing processes. This experience includes over 17 years of acting as an executive policy witness and subject matter witness at multiple electricity and gas hearings before the Manitoba Public Utilities Board (MPUB).

Mr. Rainkie's most current experience testifying before the MPUB on electricity matters includes acting as an executive policy witness at the 2016 Electric Cost of Service Methodology Review, the 2014/15 & 2015/16 Electric General Rate Application and the 2013/14 MPUB review of the Need For and Alternatives To (NFAT) MH's proposed major capital projects.

Mr. Rainkie's full curriculum vitae is attached to this evidence as **Appendix B.**

In this regulatory proceeding, Mr. Rainkie led the preparation of evidence and evaluation of MH's revenue requirement proposals of behalf the Consumers Coalition, which is contained in Sections 4.0 to 10.0 of this evidence.

2.2. Kelly Derksen – Statement of Qualifications & Duties

Ms. Derksen received her Bachelor of Science (Chemistry and Mathematics) from the University of Manitoba in 1995 and her Chartered Professional Accountant designation in 2004.

Ms. Derksen is the principal of the consulting practice she established in 2018 leveraging from nearly 25-years of experience in both a privately-owned natural gas utility and one of Canada's largest publicly-owned, vertically integrated electric and natural gas utilities. She specializes in regulation and ratemaking, with an emphasis on cost of service, and rate design.

Prior to establishing her consulting practice, Ms Derksen was employed with Centra Gas (Westcoast Energy) from 1994-1999, first as a Coordinator, Regulatory Affairs, then as a Regulatory Analyst responsible for the preparation of the Corporation's Revenue Requirement. Ms. Derksen was employed with Manitoba Hydro & Centra Gas from 1999-2017 in various analyst roles including Analyst and Senior Analyst (Gas Rates) and management roles including Manager, Gas Rates & Regulatory Services and Manager, Cost of Service.

Throughout her career, Ms. Derksen gained significant experience in all aspects of utility regulation and ratemaking including strategy, revenue requirement, cost allocation, rate design as well as the planning and management of numerous regulatory applications and associated hearing processes. This includes having

testified as a subject matter witness for over 16 years at many natural gas and electric hearings and before the Manitoba Public Utilities Board (MPUB). Ms. Derksen's most current experience testifying before the MPUB related to the 2016 Cost of Service Methodology Review, for which she was the driving force and key witness.

Ms. Derksen's full curriculum vitae is attached to this evidence as **Appendix C.**

In this regulatory proceeding, Ms. Derksen led the preparation of evidence and evaluation of MH's cost of service, rate design, and regulatory compliance proposals on behalf of the Consumers Coalition, which is contained in Sections 11.0 to 13.0 of this evidence.

2.3. William Harper – Statement of Qualifications & Duties

William Harper received his Honours Bachelor of Science in Math and Economics from the University of Toronto in 1973. He received his Master of Applied Science in Management Science (specializing in Applied Economics and Operations Research) from the University of Waterloo in 1975.

Mr. Harper has been an independent consultant since October 2018. Prior to this, Mr. Harper was an Associate with Econalysis Consulting Services. Since joining Econalysis in 2000, Mr. Harper has supported clients in Manitoba, British Columbia, Quebec, Saskatchewan and Ontario (primarily public interest groups) with their participation in regulatory proceedings on issues related to electricity utility revenue requirement determination, long-term planning (including demand-side management plans), capital project approvals, cost of service and rate design with analysis of applications and recommendations based on regulatory and economic principles.

In Manitoba, Mr. Harper has served an expert witness before the Manitoba Public Utilities Board regarding Manitoba Hydro's 2002 Status Update, 2004/05 & 05/06 General Rate Application, 2005 Cost of Service Methodology Review, 2008/09 GRA, 2013 Need For And Alternatives To Application, 2016 Cost of Service Methodology Review and the 2017/18 & 18/19 General Rate Application. In

addition, he appeared as an expert witness before the Manitoba Clean Environment Commission with respect the Wuskwatim Need For And Alternatives To Submission by Manitoba Hydro/Nisichawayasihk Cree Nation. He has also assisted clients in their participation in all other rate applications (General Rate Applications, Diesel or Interim) by Manitoba Hydro since 2002.

Mr. Harper has provided expert testimony before the Quebec Régie and the Ontario Energy Board on matters related to electricity regulation and rates. In addition he has served on numerous Working Groups established by the Ontario Energy Board to deal with specific cost of service and rate design policy issues and was a member of the Ontario Independent Electricity System Operator's Technical Panel from 2004 to 2010.

Prior to joining Econalysis Consulting, Mr. Harper worked at the Ontario Ministry of Energy for five years as an economic analyst focussing on electricity matters, and was with Ontario Hydro for 20 years. While with Ontario Hydro, he was involved in the preparation of the Company's cost of service studies and in the preparation of the rates charged to Ontario Hydro's municipal and large industrial customers. As the Manager of Ontario Hydro's Rates Department from the years 1989 to 1995 he testified regularly before the Ontario Energy Board in annual rate proceedings. At the same time he was also responsible for Ontario Hydro's policy role in regulating the rates charged by Ontario's municipal electric utilities and the annual review of their rate applications. During his final years with Ontario Hydro/Hydro One, Mr. Harper held various positions in regulatory affairs where he was responsible for coordinating applications to the Ontario Energy Board as well as submissions to the Ontario Energy Board regarding its new role in regulating the restructured Ontario electricity industry.

Mr. Harper relies on his expertise in regulatory, cost of service and rate design principles and practices in this proceeding relating to Manitoba Hydro.

Mr. Harper's full curriculum vitae is attached to this evidence as **Appendix D**.

In this regulatory proceeding, Mr. Harper led the preparation of evidence and evaluation of the changes in MH's financial forecast since the last rate application on behalf of the Consumers Coalition, which is contained in **Appendix A** of this evidence.

2.4. Duties to the MPUB and Independence

The letters retaining Mr. Rainkie, Ms. Derksen and Mr. Harper on behalf of the Consumers Coalition include that they are to provide evidence that:

- is fair, objective and non-partisan;
- is related only to matters that are within their area of expertise; and
- to provide such additional assistance as the Public Utilities Board may reasonably require to determine an issue.

In addition, the retainer letters include that their duty in providing assistance and giving evidence is to help the Public Utilities Board. This duty overrides any obligation to the Consumers Coalition. Upon signature of the retainers, it was confirmed that Mr. Rainkie, Ms. Derksen and Mr. Harper were to comply with this duty.

3.0 Introduction & Overview of MH's 2019/20 Rate Application

On November 30, 2018, MH filed an application with the PUB requesting final approval for a 3.5% rate increase for all customer classes to be effective April 1, 2019. The procedural history and content of MH's application is unique in a number of ways, which can be summarized as follows:

1. There is no corporate strategic plan;
2. There is no long-term financial plan and rate strategy and MH's long-term financial forecast and financial plan is not in scope for review in the current regulatory proceeding;
3. There is no detailed O&A forecast for 2019/20;
4. This is no prospective cost of service study for 2019/20;
5. There is no comprehensive response to PUB directives from the last rate decision (Order 59/18); and
6. The MHEB is currently in the process of undertaking a comprehensive review of MH's strategy, operations, forecasts, financial plans and rate strategy which will form the basis of MH's next GRA.

Please see the Introduction Section of **Appendix A** to this evidence for a more detailed discussion on the procedural history and content of the Application.

In its original rate application dated November 30, 2018, MH outlined the reasons for its requested rate increase of 3.5% for 2019/20, which are summarized as follows:

1. Without the proposed rate increase, MH's cumulative earnings for the three-year period from 2017/18 to 2019/20 were projected to deteriorate from those in MH Exhibit #93 by approximately $260 million. With the proposed rate increase, the deterioration would be approximately $200 million. (Original application, pages 2 and 4);
2. The lower projected financial results from 2017/18 to 2019/20 are expected to further exacerbate the $400 million of losses projected over the six-year period from 2022/23 to 2027/28, following the planned in-service of the Keeyask generating station. (Original application, page 4);

3. The 3.5% requested rate increase is aligned with PUB-approved rate increases since 2015 and keeps Manitoba's customer rates and estimated bill impacts among the lowest in North America. (Original application, page 4);
4. Without the proposed rate increase, MH was projecting a net loss of $28 million for Electric operations for 2019/20. The 3.5% proposed rate increase (effective April 1, 2019) was projected to generate additional revenues of $59 million and provide a modest contribution to financial reserves (net income) of $31 million in 2019/20. (Original application, pages 1-2); and
5. Without the proposed 3.5% rate increase, the likelihood of financial losses is greater as MH's net income has historically been extremely volatile with the key drivers of net income (water flow, weather, interest rates and export prices) being unpredictable and outside of MH's control. The proposed 3.5% rate increase would reduce the risk of MH incurring a loss in 2019/20. (Original Application, page 4).

MH filed a supplement to the application (Updated Application) on February 14, 2019 in which the 2018/19 Outlook and 2019/20 Interim Budget were updated to reflect actual financial results and water flow conditions to December 31, 2018 and well as updated planning assumptions for the 2018 Load Forecast, preliminary update to planned 2019/20 DSM expenditures, December 2018 consensus forecast of interest and US exchange rates, 2018/19 and 2019/20 projected capital expenditures, short-term forecast of export prices at December 31, 2018 and an assumed implementation of the proposed 3.5% rate increase effective June 1, 2019. (Updated Application, page 1).

The impact of the updated application on the projected financial results was significant, improving the projected net income for 2018/19 from $51 million to $95 million, or an improvement of $44 million (Updated application, Figure 2). The following schedule summarizes the impact of the update for the 2018/19 fiscal year (please note that all figures are in $million unless otherwise noted):

Figure 1 - Comparison of Projected Net Income for 2018/19 - Original & Updated Application			
	Updated Application	**Original Application**	**Increase (Decrease)**
	1	**2**	**3**
Domestic & Other Revenues (including Bipole III Deferral)	1743	1745	-2
Net Extraprovincial Revenue	183	141	42
Net Revenues	**1926**	**1886**	**40**
Other Expenses	1899	1910	-11
Net Movement in Regulatory Deferrals	-65	-69	4
Non-controlling Interest	-3	-6	3
Net Expenses	**1831**	**1835**	**-4**
Net Income	**95**	**51**	**44**
Sources:			
Column 1 - Figure 2 - Updated Application			
Column 2 - Figure 2.4 - Original Application			
Column 3 - Column 1 less Column 2			

The update also improved the projected net income (without a rate increase) for 2019/20 from a $28 million loss to a $64 million profit, or an improvement of $92 million. With the 3.5% proposed rate increase, 2019/20 net income was projected to increase from $31 million to $115 million, or an improvement of $84 million (Updated application, Figure 3). The following schedule summarizes the impact of the update for the 2019/20 fiscal year:

Figure 2 - Comparison of Projected Net Income for 2019/20 - Original & Updated Application			
	Updated Application	**Original Application**	**Increase (Decrease)**
	1	**2**	**3**
Domestic & Other Revenues (including Bipole III Deferral)	1804	1785	19
Net Extraprovincial Revenue	174	140	34
Net Revenues - without proposed rate increase	**1978**	**1925**	**53**
Other Expenses	1989	2054	-65
Net Movement in Regulatory Deferrals	-71	-103	32
Non-controlling Interest	-4	2	-6
Net Expenses	**1914**	**1953**	**-39**
Net Income - without proposed rate increase	**64**	**-28**	**92**
Proposed rate increase	51	59	-8
Net Income - with proposed rate increase	**115**	**31**	**84**
Sources:			
Column 1 - Figure 3 - Updated Application			
Column 2 - Figure 2.9 - Original Application			
Column 3 - Column 1 less Column 2			

Despite the significant improvement in the financial outlook for 2018/19 and 2019/20, MH did not amend its application to lower the proposed rate increase from 3.5%, submitting that in its view the proposed rate increase continues to be necessary and in the public interest, citing the following reasons on pages 2 to 3 of the updated application:

1. With the proposed rate increase, MH's cumulative earnings for the three-year period from 2017/18 to 2019/20 continue to be $70 million lower than those in MH Exhibit #93. (Updated application, page 2);
2. MH had accepted the more modest net income ($31 million) in the original application, in favour of balancing the interests of ratepayers and their bill impacts (Updated application, page 3);
3. The rapid turnaround of water flow conditions in the two months since filing the original application demonstrates the extreme variability in

earnings that MH can experience over a short period of time (Updated application, page 3); and

4. The proposed 3.5% rate increase continues to allow MH to plan for a modest level of net income (now $115 million) in the event that low water flow conditions or other risks arise and reduces the likelihood of future rate shock to ratepayers that could result from a financial loss in 2019/20. (Updated Application, page 3).

As part of its original application dated November 30, 2018, Manitoba Hydro is requesting approval of a 3.5% rate increase to be applied equally, across all customer classes including the new First Nations On-Reserve Class, except for Diesel General Service. For Diesel General Service customers, MH is proposing to increase the grid portion of the rates (the Basic Charge and first 2000 kWh per month) for non-government customers. The basis of MH's request for an across-the-board rate increase, but for the exception noted appears to include:

1. The consideration of a one-year electric rate application;
2. The absence of an updated Prospective Cost of Service Study ("PCOSS");
3. The anticipated significant impact on customer class costs associated with Bipole III coming into service; and
4. The on-going leave to appeal regarding the creation of the First Nations On Reserve Class that remains before the Court of Appeal.

While the updated application in which MH continues to propose a 3.5% rate increase is silent with respect to the application to cost of service and rates, it is assumed that Manitoba Hydro continues to request approval of the rate increase on an across-the-board basis. In the absence of a Formal Letter of Application that outlines the specific approvals being sought, through the course of the information request process, Manitoba Hydro advised that it is also seeking to apply the rate increase to the Basic Charge associated with the General Service

Government and First Nation Education Class[1] but exclude that Class' Energy Charge from the rate increase.

Appendix A to this Evidence provides a comprehensive review of the changes in MH's forecasts between the 2017/18 & 2018/19 GRA (MH Exbibit 93) and the current outlook (updated application) for 2017/18 to 2019/20 as well as observations for 2019/20 rate-setting purposes that flow from that detailed review. The overall rate-setting observations from the detailed review are summarized in the following table from Section 3.4 of Appendix A:

	Table A-28 - Rate-Setting Observations	
	Exhibit 93/Current Outlook Comparison	**Current Outlook**
Domestic Revenues	- Current Outlook 2018/19 Sales are likely to be higher than forecast due to colder weather post-December 2018 - Amount by which Current Outlook exceeds Exhibit 93 likely overstates PUB expectations per Order 59/18 (i.e., excludes DSM savings)	- 2018/19 Sales are likely to be higher than forecast due to colder weather post-December 2018 - DSM program savings have not been rationalized in light of lower marginal costs
Export Revenues	- Current Outlook 2019/20 Export Revenues likely to be higher due to additional sales of surplus dependable energy at premium prices	- 2019/20 Export Revenues likely to be higher due to additional sales of surplus dependable energy at premium prices
OM&A	- Current Outlook's 2019/20 OM&A costs likely overstated.	- Both the Wages and the Other Expenses for 2019/20 are likely

1 Coalition/MH 35 (a-b), page 2

		overstated. - No allowance for additional cost saving measures.
Finance	- Amount by which Current Outlook exceeds Exhibit 93 likely overstates PUB expectations per Order 59/18 (i.e., WATM)	- 2019/20 interest rates are likely to be lower than forecast. - DSM program spending has not been rationalized in light of lower marginal costs-> would lower finance expense - BOC spending has not been justified based on current need-> would lower finance expense
Depreciation		- BOC spending has not been justified based on current need
Net Movement		- DSM program spending has not been rationalized in light of lower marginal costs -> impacts DSM amortization

The sections that follow provide an evaluation of MH's reasons for application and cost of service and rate design proposals as well as conclusions drawn from this analysis and recommendations to the PUB for rate-setting in 2019/20. The overall rate-setting observations from the detailed review are incorporated into the analysis and recommendations in the following sections.

4.0 There is No Material Deterioration in MH's Financial Position since the Last GRA to Justify the Proposed 3.5% Rate Increase

In the original application, MH asserted that without the proposed rate increase, MH's cumulative earnings for the three-year period from 2017/18 to 2019/20 were projected to deteriorate from those in MH Exhibit #93 by approximately $260 million. Including the proposed rate increase, the deterioration would be approximately $200 million.

In the updated application, MH indicated that without the proposed rate increase, MH's cumulative earnings for the three-year period from 2017/18 to 2019/20 would continue to be approximately $120 million lower than those in MH Exhibit #93. Including the proposed rate increase, the deterioration would be approximately $70 million.

The following schedule summarizes MH's analysis from the updated application, with and without the proposed rate increase:

Figure 3 - MH Comparison of Actual & Projected Net Income 2017/18 to 2019/20 to Exhibit 93 - Updated Application				
	2017/18	**2018/19**	**2019/20**	**Total**
	1	**2**	**3**	**4**
Updated Application - with 2019/20 Proposed Rate Increase				
Actual & Projected Net Income	18	95	115	228
Exhibit 93 Net Income	94	143	61	298
Increase/ (Decrease)	**-76**	**-48**	**54**	**-70**
Updated Application - without 2019/20 Proposed Rate Increase				
Actual & Projected Net Income	18	95	64	177
Exhibit 93 Net Income	94	143	61	298
Increase/ (Decrease)	**-76**	**-48**	**3**	**-121**
Sources:				
Updated Application - with Proposed Rate Increase - Figure 1 Updated Application				
Updated Application - without Proposed Rate Increase - Figure 1 Updated Application - 2019/20 Net Income per Figure 7				

The following sub-sections of the evidence will analyze this MH reason for application (deterioration in financial position since the last MH GRA) from the following perspectives:

1. The appropriateness of MH including the 2017/18 actual results in this analysis given the information that was available at the 2017/18 & 2018/19 GRA (last GRA);
2. The appropriateness of MH adopting MH Exhibit #93 (from the last GRA) without any adjustments as the comparator of the PUB's expectations for MH's financial outlook for the 2018/19 and 2019/20 fiscal years; and
3. The appropriateness of MH relying solely on the cumulative level of retained earnings as the benchmark for MH's financial position rather than its three primary financial targets (key performance indicators).

4.1. The 2017/18 Actual Financial Results do not Represent a Change in Circumstance Since the Last GRA

Approximately 63% of the $120 million deterioration included in MH's calculation of the change in retained earnings since MH Exhibit #93 (without the 2019/20 proposed rate increase) relates to the 2017/18 actual net income of $18 million being $76 million lower than the projected net income of $94 million in MH Exhibit #93.

The inclusion of 2017/18 actual results in MH's calculation is unexpected when considering that the unfavorable variance from the original forecast was known at the last GRA and that one of the purposes of the last GRA was to finalize the interim rate increase that was granted by the PUB for 2017/18.

In its second quarter report for the six months ended September 30, 2017, on page 1 under Financial Overview (response to Coalition/MH I-6 c), MH stated:

> "**Manitoba Hydro** has seen a **significant deterioration in its profit outlook** for the **2017-18 fiscal year**. The corporation is **now forecasting consolidated net income for the year of approximately $40 million.** This represents a 44% decrease from 2016-17 net income of $71 million. It also **represents almost an 80% drop from our outlook for net income** from a reforecast filed with the Public Utilities Board in July. The decrease in forecast is due to the PUB's decision to deny the corporation's request for a 7.9% rate increase as at August 1, 2017, a **continuation of weak opportunity export prices**, a **relatively dry summer impacting water flow conditions** and **higher financing costs**." (Emphasis added)

The MH second quarter report was released to the public on November 14, 2017 and would have been filed with the PUB soon after the public release date. The MH third quarter report for the nine months ended December 31, 2017 contained a similar paragraph maintaining the consolidated net income forecast for 2017/18 of approximately $40 million and was released to the public on February 14, 2018.

The public hearing to review MH's 2017/18 and 2018/19 GRA occurred between December 4, 2017 and February 14, 2018. On the first day of the hearing (December 4, 2017), Mr. McCallum testified on behalf of MH at pages 200 and 201 of the transcript, that:

> "For our **electric segment**, we have seen a **$63 million drop in our outlook** for the test years' net income…**we were forecasting $93 million of net income** in this **2017/18 year**. We **now estimate that to be $30 million**, a decline of almost 70 percent." (Emphasis added)

One of the primary purposes of the last GRA was to review and finalize the 2017/18 interim rate increase of 3.36% that was approved by the PUB in Order 80/17, effective August 1, 2017. Order 59/18 was issued by the PUB on May 1, 2018 which resulted in the final approval of the interim rate increase for 2017/18 of 3.36%.

MH was aware of the deterioration in the financial outlook for 2017/18 by the fall of 2017 and in advance of the commencement of the GRA hearing on December 4, 2017. MH would have had actual financial results to January of 2018 (11 months into the fiscal year) available by the time of the closing submissions on February 14, 2018. MH could have requested that the PUB approve as final, a rate increase in excess of 3.36% for 2017/18, if it was concerned that the poorer financial results would have a material impact on its financial outlook and future rate increases. No such argument or request was made by MH at the last GRA.

The PUB was aware of the deterioration in the projected financial results for 2017/18 through the testimony at the GRA hearing and the filing of the second and third quarter MH reports on or about November 14, 2017 and February 14, 2018, respectively. The PUB would have had this information in hand when it finalized the interim rate increase for 2017/18 at 3.36% in Order 59/18 and could have approved a higher rate increase on a final basis if it was concerned about the poorer financial results and the potential impact on future rate increases.

The conclusion from this analysis is that the deterioration of actual 2017/18 financial results (which was known at the last GRA) is not a change in circumstance that should be used to justify a 3.5% rate increase two fiscal years later. If the PUB was to accept this argument, it would be inconsistent with the general principle to avoid retroactive ratemaking. Generally, rates are set on a forward-looking basis based on forecasts and not based on adjusting future rate increases as a result of past historical results.

Removing the $76 million variance related to the 2017/18 actual financial results from the MH analysis will reduce the change in retained earnings since the last GRA to $45 million ($121 million less $76 million). Even without considering if there are any adjustments that should be made to MH Exhibit #93 to appropriately conduct this analysis, a $45 million change in retained earnings from the 2019/20 projected amount of $3.047 billion in the exhibit represents a 1.5% change ($45/$3,047). This is not a material change in the projected retained earnings of a utility the size of MH.

4.2. The MH Reversion to a Debt Management Strategy consistent with a 20-year WATM Is a Known & Measurable Adjustment to MH Exhibit #93 and Does Not Represent a Change in Circumstance Since the Last GRA

MH has used MH Exhibit #93 as the comparator of the projected financial position of MH from the last GRA, citing the following passage from page 173 of Order 59/18:

> "The Integrated Financial Forecast filed in the proceeding as Manitoba Hydro Exhibit 93 supports the Board's decision on the level of the overall rate increase. This financial scenario included: … and a **debt management based on a weighted average term to maturity of 12 years**…In **many** respects…Manitoba Hydro Exhibit 93 is therefore **reflective** of **many** of the **Board's decisions** in this Order (Emphasis added)."

The key word in this quotation is the word “many” which is understood to mean that MH Exhibit #93 did not reflect all of the PUB decisions in Order 59/18. The context of this portion of the PUB findings is important to understanding its meaning and potential use at the current rate proceeding. The MH Financial Plan and rate strategy that was advanced at the last GRA was a radical departure from prior GRA’s and there were numerous versions of competing financial scenarios that were placed on the public record by all parties. It would appear that in making this reference to MH Exhibit #93, the PUB was simply attempting to find a financial scenario that was reasonably consistent with its findings within the plethora of scenarios on the record at the last GRA. It is also worth noting, that none of the financial scenarios presented at the hearing would exactly match the final decisions that would subsequently be made by the PUB in Order 59/18. The MH compliance filing did not include a revision to MH Exhibit #93 that reflected the PUB’s decisions and directives from Order 59/18.

It is clear from a review of Order 59/18 that the PUB understood that MH Exhibit #93 reflected a 12-year WATM. The PUB also found that the costs of the 12-year WATM plan outweighed the benefits for consumers and that the impact of MH’s reversion to a debt management strategy consistent with a 20-year WATM (as a result of a flattening yield curve) would result in a significant deterioration of the financial outlook in Exhibit #93. The following passages from the PUB findings in Order 59/18 supports these conclusions:

> “The **Board does not accept that the rate increases should be higher** in order to **allow Manitoba Hydro to retire debt** according to their debt management plan…**Manitoba Hydro’s recently amended approach to the debt management plan, whereby it placed longer-term debt issues to take advantage of a flattening yield curve**, demonstrates that Manitoba Hydro’s treasury function is well exercised…While there are benefits to a shorter-term debt retirement plan, **such a plan imposes a cost on ratepayers that is not justified by the evidence.**” (Order 59/18, page 68, emphasis added)

> "…the **opportunity for Manitoba Hydro** to now **shorten the weighted average term to maturity** of new debt issuance from approximately **20 to 12 years** so as to retire debt permanently…The **financial benefit associated with this opportunity** has the potential to provide a **reduction in debt servicing costs of $500 million**….However, **Manitoba Hydro revised its estimate** of the **reduction in debt servicing costs during the GRA** hearing down to **under $250 million** as a **result of the recent flattening of the yield curve** between shorter-term (five year) and longer-term (30 year) debt." (Order 59/18, page 53, emphasis added)

MH's evidence that the benefits of the alternate debt management strategy would be reduced by $250 million as a result of changes in the yield curve can be found in the testimony of Ms. Stephen during the revenue requirement panel, December 6, 2017, pages 705 to 706 of the transcript:

> "Our forecast had modeled a 1.6% difference between the five-year and thirty (30) year borrowing rate. The **differential between these two (2) rates is what provided for the approximate $500 million in savings that we had put forward in our new terming methodology**…So the **differential between the five year and thirty (30) year rate has diminished now to about .9 percent. What this does is this has the effect of reducing the savings available from changing our terming strategy…It actually comes in some where, when we modelled it, just under 250 million in savings**." (Emphasis added)

In issuing Order 59/18, the PUB was fully aware that the reversion back to a debt management strategy consistent with a 20-year WATM (as a result of a flattening yield curve) would reduce the financial outlook in MH Exhibit #93 by about $250 million but accepted the trade-off as being beneficial to customers. Using this deterioration (which was expected at the last GRA) as a reason for a rate increase in 2019/20 is not consistent with the findings in Order 59/18.

The conclusion from this analysis is that the reduction in the 2018/19 and 2019/20 projected financial results related to a reversion to a 20-year WATM

represents a known and measurable adjustment that should be made to MH Exhibit #93 to make this financial scenario more comparable with the PUB expectations flowing from Order 59/18. The reversion to a debt management strategy consistent with a 20-year WATM is not a change in circumstances since the last GRA that should be used to justify a 3.5% rate increase in 2019/20.

In the response to Coalition/MH I-6 a, MH indicates that the reversion back to a 20-year WATM is projected to increase finance expense in 2018/19 by $20 million and in 2019/20 by $33 million, respectively, which would in turn decrease the expected net income in MH Exhibit #93 to $123 million for 2018/19 and $28 million for 2019/20 (including the indicative rate increase of 3.57%).

Adjusting Figure 1 from MH's updated application to remove 2017/18 actual results (Section 4.1) and make a known and measurable adjustment to MH Exhibit #93 for the expectation of a 20-year WATM results in the following analysis that demonstrates that cumulative retained earnings projected to 2019/20 are higher than those in the adjusted MH Exhibit #93:

Figure 4 - Comparison of Projected Net Income 2018/19 to 2019/20 to Exhibit 93 Adjusted for 20 Year WATM - Updated Application

	2018/19	2019/20	Total
	1	2	3
Updated Application - with 2019/20 Proposed Rate Increase			
Adjusted for 20 Year WATM			
Actual & Projected Net Income	95	115	210
Exhibit 93 Net Income - adjusted for 20 year WATM	123	28	151
Increase/ (Decrease)	**-28**	**87**	**59**
Updated Application - without 2019/20 Proposed Rate Increase			
Adjusted for 20 Year WATM			
Actual & Projected Net Income	95	64	159
Exhibit 93 Net Income - adjusted for 20 year WATM	123	28	151
Increase/ (Decrease)	**-28**	**36**	**8**

Sources:

Updated Application - with Proposed Rate Increase - WATM adjustment per Coalition/MH I-6 a

Updated Application - without Proposed Rate Increase - WATM adjustment per Coalition/MH 1-6 a

This analysis demonstrates that the contributions to financial reserves (net income) projected in 2018/19 and 2019/20 are $59 million higher than those in the adjusted MH Exhibit #93 with the 3.5% proposed rate increase and are still $8 million higher than those in the adjusted MH Exhibit #93 without the 3.5% proposed rate increase.

It is also noted that the winter of 2018/19 has been consistently colder than normal (See Section 4.1, Appendix A) and that MH indicates that colder than normal winter weather can positively impact its financial results up to approximately $50 million. As such, it is possible that actual financial results for 2018/19 could very well exceed the adjusted forecast of $123 million from MH Exhibit #93, further contributing to this improved outlook.

On an overall basis, this analysis demonstrates that there is no material deterioration in the financial results (net income) of MH from that which was expected at the last GRA.

4.3. The Most Appropriate KPI's to Use to Assess MH's Financial Position is its Three Primary Financial Targets

As noted above, MH has performed its analysis of the change in financial position based solely on the cumulative retained earnings to 2019/20. MH did not provide projections of its financial ratios in its original application and as such it is understood that these financial ratios were not relied upon by MH in developing its reasons for the proposed 3.5% rate increase.

In its report on performance in the 2017/18 Annual Report (Page 20 of Appendix 3 to the original application) which was released to the public on July 27, 2018, under the strategic priority of financial sustainability – MH provides its three long-standing financial ratios that it has historically used to measure its financial health – 1) Debt/Equity ratio 2) Interest Coverage ratio and 3) Capital Coverage ratio. The inclusion of these three ratios as Key Performance Indicators (KPI's) in the

last MH annual report presumably indicates that the recently appointed MHEB endorses them for the purposes of measuring and communicating its financial health to stakeholders.

While the MH financial targets were the subject of much discussion at the last MH GRA, very briefly, the description and purpose behind the long-standing three primary financial targets are as follows (from page 2 of Tab 4 of the last GRA):

1. Maintain a minimum equity ratio of 25%, a measure of the portion of assets that are financed by internally generated funds rather than debt;
2. Maintain an earnings before interest, taxes, depreciation and amortization (EBITDA) interest coverage ratio with a minimum target of greater than 1.80, which measures the ability to meet interest payments with cash flow; and
3. Maintain a capital coverage ratio of greater than 1.20, which is a measure of the ability of cash flow from operations to fund sustaining capital expenditures.

The three primary financial ratios incorporate elements of the balance sheet (equity and debt), income statement (EBITDA) and the cash flow statement (cash flow from operations, internally generated funds) and in doing so, provide a more complete and robust picture of MH's financial health than using a simple and stand-alone metric of cumulative retained earnings.

On pages 61 and 62 of Order 59/18, the PUB outlined its findings with respect to MH's new financial plan and financial ratios:

> "…the **Board finds** that a **particular equity level target and pace to achieve that target should not determine the rate increases approved in this GRA**…the **Board's assessment must include consideration of the circumstances of Manitoba Hydro's operations**…it has historically undertaken large investments such as generating stations and transmission lines that have initial large surpluses of capacity for the needs of Manitobans. These assets have **large upfront construction**

> **costs** but **relatively low annual operating costs** that extend through a **very long expected useful life**…With Manitoba Hydro's investments currently underway in Keeyask and Bipole III, the situation today is no different.
>
> An **important question from a rate-setting perspective is how these large investments should be funded**…The concern is to find the **right balance between** the **rate increases** and the **level of debt** to fund large capital projects.
>
> In making this determination, the **Board is guided by two considerations**. The **first** is: **what "reserves" should Manitoba Hydro hold** to manage risk and **which risks should it take into account**…The **second** is to **place concerns** about the **amount of debt** and **retained earnings** in a **different perspective by also considering cash flow**, using two long-standing financial metrics used by Manitoba Hydro: **interest coverage ratio** and the **capital coverage ratio**." (Emphasis added)

It is clear from the above passages from Order 59/18 and previous rate decisions, that the PUB considerations to set rates for MH involve a complex review of a number of financial metrics including financial reserves, debt levels, interest coverage and capital coverage.

The conclusion from this section of the analysis is that the most appropriate KPI's or metrics to use to asses the financial position of MH **in this application** are its three primary financial targets. The updated projections with respect to the three financial ratios are analyzed in sections 4.4, 4.5 and 4.6.

It is also noted that MH has made the following changes to its cash flow statement for financial reporting purposes in its most recent audited financial statements for 2017/18 (Appendix 3, page 69):

1. Change from the direct method to the indirect method of presenting cash flow from operations; and

2. Capitalized interest has been reclassified from cash flow from investing activities to cash flow from operating activities so that all interest paid is included in one-line of the cash flow statement.

While the evaluation of these changes for rate-setting purposes is likely to be the subject of greater review at the next full GRA, the initial comments are that the first change to the indirect method provides a finer level of detail in terms of understanding the cash flow from operations in that it starts with net income and then makes adjustments for non-cash items such as deprecation and working capital changes. This additional information is likely useful in understanding cash flow from operations for rate-setting purposes and does not change the amount of cash flow from operations. Information on the direct method can also be provided by MH if required for rate-setting purposes.

The second change to reclassify interest capitalized on capital projects from investing activities to operating activities is potentially concerning from a rate-setting perspective. This change will serve to reduce the cash flow from operations as capitalized interest will now be deducted from operating cash flows as part of interest paid, rather than being included as part of additions to property, plant and equipment or intangible assets in investing activities. This change will serve to alter the perception of the amount of cash flow that is available to meet financial obligations and fund sustaining capital expenditures on MH's audited financial statements.

The PUB findings with respect to cash flow from operations from pages 66 to 67 of Order 59/18 are as follows:

> "**Cash Flow from Operations** …The Board finds that, **in assessing whether Manitoba Hydro is meeting its ongoing financial obligations,** the **focus should be on the accrual accounting** methodology used in the Utility's audited financial statements…**Accrual accounting** used by Manitoba Hydro **includes capitalizing interest to capital projects until those assets enter service for ratepayers**…**Once in service**, **financing**

and deprecation **costs are recorded on the Income Statement** to be recovered in consumer rates" (Emphasis added)

It is understood that the above noted passage from Order 59/18 is intended to convey that for rate-setting purposes the PUB will consider capitalized interest to be part of investing activities until the related assets are placed into service, at which time this interest will be considered as part of operating activities.

The reclassification of capitalized interest to operating activities for financial reporting purposes will be inconsistent with the treatment for rate-setting purposes and as such may cause confusion. When asked if it would continue to provide cash flow and capital coverage ratio information for rate-setting purposes in future GRA's under the previous presentation methodology, MH indicated (response to Coalition/MH I-6 m) that the capital coverage ratio will not change from how the ratio has been calculated in previous years.

4.4. The Debt to Equity Ratio for MH for 2019/20 has Not Materially Deteriorated since the Last GRA

The following schedule provides a comparison of the calculation of MH's projected Debt to Equity ratio for 2019/20 for the updated application (without the proposed rate increase for 2019/20), with MH Exhibit #93 adjusted for a 20-Year WATM and with MH Exhibit #93 from the last GRA:

Figure 5 - Comparison of Projected Debt/Equity Ratio to Exhibit 93 - 2019/20				
				Updated vs.
	Updated	Exhibit 93		Exhibit 93
Updated Application - without 2019/20 Proposed Rate Increase	Application	Adjusted	Exhibit 93	Adjusted
	1	2	3	4
Long-term Debt (including current portion)	22832	23682	23682	-850
Short-tem debt	0	0	0	0
Less: short-term investments	-687	-475	-523	-212
Less: sinking fund investments	-84	-531	-531	447
Net Debt	**22061**	**22676**	**22628**	**-615**
Retained Earnings	2926	2990	3047	-64
Accumulated other comprehensive loss	-675	-580	-580	-95
Unamortized customer contributions	761	784	784	-23
Non-controlling Interest	294	306	306	-12
Total Equity	**3306**	**3500**	**3557**	**-194**
Total Debt & Equity	**25367**	**26176**	**26185**	**-809**
Equity Ratio	**13.03%**	**13.37%**	**13.58%**	**-0.34%**
Debt Ratio	**86.97%**	**86.63%**	**86.42%**	**0.34%**
Sources:				
Column 1 - response to Coalition/MH 6 j				
Column 2 - response to Coalition/MH 6 b ii				
Column 3 - response to Coalition/MH 6 b i				
Column 4 - Column 1 less Column 2				

The key observations from this schedule when comparing the updated application (without the proposed rate increase) with the adjusted MH Exhibit #93 calculation are as follows:

1. The projected total equity excluding AOCI at the end of 2019/20 is $3.981 billion in the updated application (without the proposed rate increase) and $4.080 billion in the adjusted MH Exhibit #93, a decrease of $99 million;
2. The projected AOCI loss at the end of 2019/20 is $675 million in the updated application (without the proposed rate increase) and $580 million in the adjusted MH Exhibit #93, an increase in the loss of $95 million;
3. The projected net debt at the end of 2019/20 is $22.061 billion in the updated application (without the proposed rate increase) and $22.676 billion in adjusted MH Exhibit #93, a decrease of $615 million; and
4. The projected Equity ratio at the end of 2019/20 is 13.03% in the updated application (without the proposed rate increase) and 13.37% in adjusted MH Exhibit #93, a decrease of 0.34%.

The three primary components of the projected changes in the Equity ratio since the last GRA is a decrease in retained earnings, an increase in the AOCI loss and a decrease in net debt. The decrease in retained earnings is a function of lower projected net income. The decrease in net debt is primarily a function of lower capital expenditures. The increase in the AOCI loss is primarily a result of the pension loss recorded at March 31, 2018 and a projected pension loss not forecast in MH Exhibit #93 (response to Coalition/MH I – 6 k).

The following schedule isolates the impact of the increase in the AOCI loss of $95 million by holding the AOCI loss constant at $580 million in the updated application (without the proposed rate increase) and comparing that calculation to the adjusted MH Exhibit #93:

Figure 6 - Comparison of Projected Debt/Equity Ratio to Adjusted Exhibit 93 - 2019/20				
				Upated vs.
		Updated	**Exhibit 93**	**Exhibit 93**
Updated Application - without 2019/20 Proposed Rate Increase		**Application**	**Adjusted**	**Adjusted**
Adjusted for 20 Year WATM & AOCI held constant		**1**	**2**	**3**
Long-term Debt (including current portion)		22832	23682	-850
Short-tem debt		0	0	0
Less: short-term investments		-687	-475	-212
Less: sinking fund investments		-84	-531	447
Net Debt		**22061**	**22676**	**-615**
Retained Earnings		2926	2990	-64
Accumulated other comprehensive loss		-580	-580	0
Unamortized customer contributions		761	784	-23
Non-controlling Interest		294	306	-12
Total Equity		**3401**	**3500**	**-99**
Total Debt & Equity		**25462**	**26176**	**-714**
Equity Ratio		**13.36%**	**13.37%**	**-0.01%**
Debt Ratio		**86.64%**	**86.63%**	**0.01%**
Sources:				
Column 1 - response to Coalition/MH 6 j & AOCI held constant at $580 m for updated application				
Column 2 - response to Coalition/MH 6 b ii				
Column 3- Column 1 less Column 2				

As the above schedule indicates, the small reduction in the Equity ratio in the updated application (without the proposed rate increase) for 2019/20 is almost entirely the result of the change in the AOCI loss related to changing assumptions with respect to unrealized pension losses that are recorded in AOCI and will not be reclassified to net income (see the Consolidated Statement of Comprehensive Income – page 68 of Appendix 3).

If the AOCI loss is held constant, then the Equity ratio (without the proposed rate increase) is 13.36% which is virtually identical to the 13.37% Equity ratio in the adjusted MH Exhibit #93 calculation. The impact of lower equity levels and lower debt levels since MH Exhibit #93 was prepared are offsetting. Therefore, the conclusion with respect to the Equity ratio is that there is no material deterioration in the Equity ratio for MH, without a rate increase in 2019/20.

4.5. The Interest Coverage Ratio for MH for 2019/20 has Slightly Improved since the Last GRA

The following schedule provides a comparison of the calculation of MH's projected Interest Coverage ratio for 2019/20 for the updated application (without the proposed rate increase) for 2019/20), with MH Exhibit #93 adjusted for a 20-Year WATM and with MH Exhibit #93 from the last GRA:

Figure 7 - Comparison of Projected Interest Coverage Ratio to Adjusted Exhibit 93 - 2019/20					
					Updated vs.
		Updated	Adjusted		Adjusted
Updated Application - without 2019/20 Proposed Rate Increase		**Application**	**Exhibit 93**	**Exhibit 93**	**Exhibit 93**
Adjusted for 20 Year WATM		**1**	**2**	**3**	**4**
Net Income		64	28	61	36
Finance Expense (Net)		748	761	727	-13
Capitalized Interest		311	319	319	-8
Depreciation Expense		530	541	541	-11
EBITDA		**1653**	**1649**	**1648**	**4**
Finance Expense (Net)		748	761	727	-13
Capitalized Interest		311	319	319	-8
Total Interest		**1059**	**1080**	**1046**	**-21**
Interest Coverage Ratio		**1.56**	**1.53**	**1.58**	**0.03**
Sources:					
Column 1 - response to Coalition/MH 6 j					
Column 2 - response to Coalition/MH 6 b ii					
Column 3 - response to Coalition/MH 6 b i					
Column 4 - Column 1 less Column 2					

The key observations from the above noted schedule when comparing the updated application (without the proposed rate increase) with the adjusted MH Exhibit #93 calculation are as follows:

1. The projected EBITDA for 2019/20 in the updated application (without the proposed rate increase) is $1.653 billion and $1.649 billion in adjusted MH Exhibit #93, an increase of $4 million;
2. The projected total interest (including capitalized interest) for 2019/20 is $1.059 billion in the updated application (without the proposed rate increase) and $1.080 billion in adjusted MH Exhibit #93, a decrease of $21 million; and
3. The projected Interest Coverage ratio at the end of 2019/20 is 1.56 in the updated application (without the proposed rate increase) and 1.53 in adjusted MH Exhibit #93, an increase of 0.03.

Therefore, the conclusion with respect to the Interest Coverage ratio is that there is a slight improvement in the Interest Coverage ratio for MH due to lower projected interest costs, without a rate increase in 2019/20.

4.6. The Capital Coverage Ratio for MH for 2019/20 has Slightly Improved since the Last GRA

The following schedule provides a comparison of the calculation of MH's projected Capital Coverage ratio for 2019/20 for the updated application (without the proposed rate increase) for 2019/20), with MH Exhibit #93 adjusted for a 20-Year WATM and with MH Exhibit #93 from the last GRA:

Figure 8 - Comparison of Projected Capital Coverage Ratio to Exhibit 93 - 2019/20					
					Updated vs.
		Updated	Adjusted		Adjusted
Updated Application - without 2019/20 Proposed Rate Increase		Application	Exhibit 93	Exhibit 93	Exhibit 93
Adjusted for 20 Year WATM		1	2	3	4
Funds from Operations		280	N/A	N/A	N/A
Capitalized Interest		311	N/A	N/A	N/A
Internally Generated Funds		591	579	608	12
Electric Capital Expenditures		478	516	516	-38
Capital Coverage Ratio		1.24	1.12	1.18	0.11
Sources:					
Column 1 - response to Coalition/MH 6 j					
Column 2 - response to Coalition/MH 6 b ii					
Column 3 - response to Coalition/MH 6 b i					
Column 4 - Column 1 less Column 2					

The key observations from the above noted schedule when comparing the updated application (without the proposed rate increase) with the adjusted MH Exhibit #93 calculation are as follows:

1. The projected Electric Funds from Operations for 2019/20 is $591 million in the updated application (without the proposed rate increase) and $579 million in adjusted MH Exhibit #93, an increase of $12 million;

2. The projected Business Operations Capital for 2019/20 is $478 million in the updated application (without the proposed rate increase) and $516 million in adjusted MH Exhibit #93, a decrease of $38 million; and
3. The projected Capital Coverage ratio for 2019/20 is 1.24 in the updated application (without the proposed rate increase) and 1.12 in adjusted MH Exhibit #93, an increase of 0.12.

Therefore, the conclusion with respect to the Capital Coverage ratio is that there is a slight improvement in the Capital Coverage ratio for MH primarily as a result of lower projected business operations capital expenditures, without a rate increase in 2019/20.

5.0 The PUB Does Not Have Adequate Evidence to Find That There Will be an Exacerbation of Losses After the In-service of Keeyask That Will Increase the Likelihood of Future Rate Shock

In the original application, MH asserted that the lower projected financial results from 2017/18 to 2019/20 are expected to further exacerbate the $400 million of losses projected over the six-year period from 2022/23 to 2027/28, following the planned in-service of the Keeyask generating station. In the updated application, MH went further to assert that the proposed 3.5% rate increase continues to allow MH to plan for a modest level of net income in the event of low water flow conditions and reduces the likelihood of future rate shock to ratepayers that could result from a financial loss in 2019/20.

The previous section of the evidence (Section 4.0) reviewed MH's assertion that there is a projected deterioration in MH's financial position since the last GRA and concluded that there is no material deterioration in MH's financial position to the 2019/20 fiscal, even in the absence of a rate increase in 2019/20.

This section of the evidence will analyze this MH reason for application (exacerbation of losses after the in-service of Keeyask that increase likelihood of future rate shock) from the following perspectives:

1. The appropriateness of MH self imposing a one-year rate application and cautioning the PUB with respect to future losses from years six to 11 of MH Exhibit #93, while at the same time not providing a long-term IFF to guide the PUB in setting rates;
2. The appropriateness of MH relying on MH Exhibit #93 (MH 16 Updated) to caution the PUB with respect to future losses when IFF updates are subject to significant changes; and
3. The appropriateness of MH relying on MH Exhibit #93 (MH 16 Updated) to caution the PUB with respect to future losses when the MHEB is currently conducting a comprehensive review of MH's strategy, operations, finances and rate strategy.

5.1. The Modified Cost of Service Rate-Setting Framework that Has Traditionally Been Used to Set Electricity Rates in Manitoba Is Dependent on a Long-Term Financial Forecast

The Modified Cost of Service (MCOS) rate-setting framework that has been traditionally applied for decades in the setting of electricity rates for MH is dependent on MH's long-term financial forecast (referred to as the Integrated Financial Forecast or IFF).

The historic MCOS approach "looks past" the test-year(s) under review by using the long-term IFF and allowing the PUB to make informed judgements on how the proposed rate increase in the test year(s) impact the longer-term financial outlook and rate trajectory for MH. The MCOS approach is essentially a rate-smoothing approach designed to promote rate stability and predictability for customers and balance the financial integrity of MH with the rate impacts on customers over the longer-term. The MCOS can be referred to as a "horizontal" rate-setting approach in that it looks over the longer-term planning horizon to make rate-setting determinations in the current test year(s).

The importance of a long-term IFF to the MCOS rate-setting approach can be demonstrated by considering that the fact that MH has filed a fully updated IFF to support the proposed rate increases during the recent years of requests for interim rate applications, even in the circumstances where there has been an expedited regulatory process (2014/15 and 2016/17).

The MCOS approach can be contrasted with the more formulaic Rate Base/Rate of Return (RBROR) rate-setting framework that is used in many jurisdictions to determine revenue requirements and set rates based primarily on consideration of the financial forecasts of a single test-year(s) and is designed to allow the utility the opportunity to earn an approved return on equity (net income) based on an approved capital structure (debt to equity ratio). The RBROR can be referred to as a "vertical" rate-setting approach in that it looks specifically at the test-year revenues and expenses to make rate-setting determinations based on a formula.

The RBROR approach was used for many decades by the PUB to set gas rates while Centra Gas was owed privately. With the transition to ownership by Manitoba Hydro, gas rates are now set using what could be referred to as a modified RBROR approach (MRBROR). The allowed net income is not derived by applying an approved rate of return on equity to an approved rate base as is the case in a traditional RBROR approach. Under the MRBROR approach, gas rates are set by adding a corporate allocation and net income to the other cost of service expenses (O&A, deprecation, interest etc.) to generate a specific financial outcome – namely a modest net income.

5.2. It Is Not Possible for the PUB to Use the Modified Cost of Service Rate-Setting Framework to Set Rates in 2019/20 in the Absence of a Reliable, Long-Term and Integrated Financial Forecast

In advancing the 2019/20 Rate Application, MH has been very clear that it was expecting a review of a "one-year" rate application and it was unable to produce an updated IFF as a result of a comprehensive review of MH's strategy, operations, finances and rate strategy by the recently appointed MHEB.

In the 2019/20 Rate Application, MH has essentially self-imposed a "one-year" rate application that is consistent with a vertical rate-setting approach like the MRBROR that is used to set rates for Centra Gas and in making this decision, has significantly departed from the traditional MCOS rate-setting approach by not providing the PUB with a long-term IFF to guide rate-setting. MH has requested a significant 3.5% rate increase (by recent comparisons) on a final basis for 2019/20 based on a rate filing that is inferior to the past GRA and interim rate applications which were all supported by updated and long-term IFF's.

The central theme of the current application is that rates for 2019/20 should be set such that MH has the opportunity to earn a modest net income and make a modest contribution to financial reserves for 2019/20, while the recently appointed MHEB conducts a comprehensive operational and financial review of MH and articulates a long-term strategic and financial plan and rate strategy.

While MH has self-imposed a MRBROR like vertical rate-setting approach for 2019/20 it has cautioned the PUB to be cognizant of previous IFF's filed with the PUB that forecast a significant deterioration in financial results ($400 million of losses in MH Exhibit #93) following the in-service of the Keeyask generating station.

MH's one-year application presents an issue for the PUB and intervenors in terms of the appropriate rate-setting framework/approach to use to evaluate MH's proposed rate increase as well as the evidence to support the most appropriate rate-setting evaluation criteria. On the one-hand, MH has been very clear about the one-year application considering the comprehensive MHEB review but on the other hand has used potential future losses from years six to 11 of an outdated IFF (MH Exhibit #93) to justify its proposed rate increase. Seemingly, MH wants to impose a one-year rate application consistent with the MRBROR approach while still using elements of a MCOS approach, without providing the necessary evidence to the PUB in the form of a longer-term IFF.

MH attempts to bridge the limitations of its short-term rate application in the response to Coalition/MH I-1 b by layering KHLP revenues (from MFR 7 from the last GRA) on top of 2019/20 revenues (without the 3.5% proposed rate increase) and revenue requirements from Keeyask, MMTP and GNTL (updated response to PUB/MH I-9) on top of 2019/20 total expenses, noting that a one-time rate increase of 18% or three 5.5% rate increases over three years would be required to breakeven.

The relevance of MH's calculation of a 18% one-time or three 5.5% increases to breakeven in the response to Coalition/MH I-1 b is not known. It is clear from the PUB's findings and recommendations at NFAT and the rejection of a financial plan/rate path with 7.9% rate increases in Order 59/18 that the rate increase scenarios presented in this information response are not realistic in an era of unprecedented major capital investment with very long expected useful lives and are not supported by the principles of rate stability and predictability.

Curiously, while using the incremental revenue requirement calculations for Keeyask, MMTP and GNTL in the response to Coalition/MH I -1 b to justify its proposed rate increase, MH takes great care to emphasize the limitations with respect to these very same calculations for rate-setting purposes in the updated response to PUB/MH I-9:

> "The **most reliable measure of Manitoba Hydro's revenue requirements is the additional Domestic Revenue indicated on the electric operations projected operating statement** (Appendix 1 (Updated), page 1 of 4) **which is derived based on balancing the costs of the integrated hydro-electric system**, for new asset additions as well as existing assets, **with maintaining minimum financial ratios** as well as **rate stability and affordability for customers.**
>
> **The type of analysis requested in this IR is limited by virtue of treating individual projects on an incremental cost basis.** While costs such as Depreciation Expense, Water Rentals, and Operating & Administrative Expenses may be estimated and may be directly attributable to a Major New Generation and Transmission asset, other costs such as Finance Expense, capital taxes and benefits are not readily estimated on an incremental basis. Furthermore, this analysis disregards the estimated export revenues to be obtained through sales of surplus energy associated with new electric generating plant.
>
> **Reliance on the estimated carrying and operating costs** in these schedules **as a representation of revenue requirement** must be **viewed with caution** considering the **inherent limitations of the analysis, estimate assumptions and methods** described below." (Emphasis added)

MH also provides the following caution with respect to determining the rate-setting implications of considering certain information in isolation in the response to Coalition/MH I-25 c:

> "With respect to the rationale for this question, it is important to recognize that **Manitoba Hydro operates in a complex environment with multiple interdependencies**, which makes it **difficult to deduce rate setting implications** by **looking at certain updated information in isolation of other factors** and **without a detailed assessment of their impacts.**" (Emphasis added)

From these responses to information requests, it is obvious that MH itself, recognizes the limitations of incremental or stand-alone calculations in isolation and should understand that this is not sufficient evidence for the PUB to make rate-setting determinations or apply the historic MCOS rate-setting approach in absence of a long-term and integrated financial forecast.

5.3. MH's IFF's are Subject to Significant Changes when they are Updated for More Current Information and Planning Assumptions

Traditionally, the PUB has expressed a strong desire to make rate-setting decisions based on the most current and up to date forecasts and planning assumptions. This approach is well founded given the significant changes that can occur between regular updates of the MH long-term IFF.

The following schedule provides a historic review of the last five MH IFF's that have been used for rate-setting and the forecast net income for electric operations in each year of the forecast:

Figure 9 - Comparison of Projected Electric Net Income (Loss) MH12 to Exhibit 93 (MH 16 Updated)					
Year	**Exhibit 93**	**MH15**	**MH14**	**MH13**	**MH12**
2018	94	63	64	**-12**	19
2019	143	**-41**	**-90**	**-67**	**-68**
2020	61	21	**-116**	**-31**	**-9**
2021	115	**-13**	**-178**	**-75**	**-7**
2022	178	6	**-206**	**-60**	52
2023	**-29**	**-4**	**-187**	6	163
2024	**-111**	56	**-124**	68	228
2025	**-69**	129	**-53**	133	301
2026	**-128**	129	**-24**	168	358
2027	**-68**	232	84	281	418
2028	**-13**	319	155	277	370
2029	81	439	266	259	534
2030	190	520	400	408	710
2031	261	592	536	532	835
2032	398	694	647	742	1054
2033	512	769	725	952	**N/A**
2034	641	849	826	**N/A**	**N/A**
2035	793	946	**N/A**	**N/A**	**N/A**
2036	883	**N/A**	**N/A**	**N/A**	**N/A**
Cumulative Net Income (Losses):					
1. 6 Years after Keeyask In-Service					
a) Exhibit 93 - 2023 to 2028	**-418**				
b) MH12 to MH 15 - 2021 to 2026		303	**-772**	240	1095
2. 2023 to 2028	**-418**	861	**-149**	933	1838
3. 2018 to 2028	173	897	**-675**	688	1825
4. Period of Losses MH14 - 2019 to 2026	160	283	**-978**	142	1018

The key observations from the above schedule are as follows:

1. The projected cumulative financial results for the six-years (2020/21 to 2025/26) after the in-service of Keeyask in MH12 was $1.095 billion of profits;
2. The projected cumulative financial results for the six-years (2020/21 to 2025/26) after the in-service of Keeyask in MH13 was $240 million of profits;
3. The projected cumulative financial results for the six-years (2020/21 to 2025/26) after the in-service of Keeyask in MH14 was $772 million of losses;

4. The projected cumulative financial results for the six-years (2020/21 to 2025/26) after the in-service of Keeyask in MH15 was $303 million of profits; and
5. The projected cumulative financial results for the six-years (2022/23 to 2027/28) after the in-service of Keeyask in MH Exhibit #93 (MH16 Updated) was $418 million of losses.

This analysis clearly demonstrates that with each update of the IFF there has been a significant change in the trajectory of MH's financial outlook with the projected financial results oscillating back and forth from a profit in MH12 and MH13 to significant losses in MH14, back to a profit in MH15 and then back to losses in MH Exhibit #93 (MH16 Updated).

MH Exhibit #93 is based on MH 16 Updated. According to page 1 of the Supplement to Tab 3 from the last GRA, MH 16 Updated is based on forecasts and assumptions that were gathered over the timeframe between May of 2016 and January of 2017 with select updates for information available to early July of 2017.

The conclusion that can be drawn from this analysis is that MH Exhibit #93 which contains significantly outdated planning assumptions (from early 2017) cannot be used by the PUB as reliable evidence to approve a 3.5% rate increase in the spring of 2019 (almost two years later) based on projections of losses six to 11 years forward in that forecast (from 2022/23 to 2027/28).

5.4. MH's Next IFF could Change Significantly as a Result of the MHEB Comprehensive Review of MH's Strategy, Operations, Financial Plan and Rate Strategy

As was outlined by MH in the original application, the recently appointed MHEB is conducting a comprehensive operational and financial review of MH in order to articulate a new long-term strategic and financial plan. Presumably, this comprehensive review will include updates to MH's strategies, operations and financial projections including revenues, expenses, capital expenditures, debt

management plans and rate strategy (responses to Coalition/MH I-4 c d and MIPUG/MH I-5).

Upon the MHEB's development and approval of a long-term financial plan, MH is expected to submit a full GRA to the PUB. This review is the key reason provided by MH for not producing an updated IFF for the PUB's consideration of the 2019/20 Rate Application.

As can be seen in the last MH GRA, a comprehensive review of MH's operations and finances by the previous MHEB resulted in a significant change in the approach, financial plan and rate strategy of MH.

The possibility of change in MH's strategic and financial direction as a result of the latest MHEB comprehensive review is further underscored by MH's response to PUB/MH I-1 - when requested by the PUB to confirm that MH's evidence given in the 2017/18 & 2018/19 GRA proceeding and hearing is accepted as evidence in the 2019/20 proceeding, except where modified or changed in the 2019/20 evidence – MH responded as follows:

> "**Not confirmed**. The **2017/18 & 2018/19 GRA** was **based upon a long-term financial forecast** which has **not been endorsed by Manitoba Hydro's current Board of Directors**, and **may not be consistent with the outcome of the comprehensive review** to be undertaken **by the Board of Directors**." (Emphasis added)

The conclusion that can be drawn from the review of the circumstances leading to and the content in the MH 2019/20 Rate Application is that the longer-term financial outlook in MH Exhibit #93 (years six to 11 of the forecast) is in no way endorsed by the recently appointed MHEB and could significantly change as a result of the review and as such, cannot be used by the PUB as reliable evidence to approve a 3.5% rate increase for 2019/20.

6.0 Observations with Respect to the Level of Past Approved Rate Increases or Jurisdictional Rate Comparisons are Not Valid Justifications for the Proposed Rate Increase

MH has asserted that the 3.5% proposed rate increase is aligned with PUB-approved rate increases since 2015 and keeps Manitoba's customer rates and estimated bill impacts among the lowest in North America.

This section will analyze these two MH reasons for application (alignment with prior PUB-approved rate increases and customer rates & bill impacts among the lowest in North America) from the following perspectives:

1. How does the 3.5% proposed rate increase compare to recently PUB-approved rate increases;
2. Is alignment with recently PUB-approved rates increases a justification for a 3.5% rate increase in 2019/20; and
3. Do jurisdictional rate comparisons provide justification for a 3.5% rate increase in 2019/20 or respond to the PUB expectations from Order 59/18 with respect to assessing the broader impacts of proposed rate increases on the Manitoba economy or bill affordability for customers.

6.1. The Proposed 3.5% Rate Increase is a Significant Rate Increase with a Present Value to Customers in the Order of $1.4 Billion

A review of the PUB-approved electric rate increases since 2014/15 is as follows:

Figure 10 - Summary of Recent PUB Electric Rate Increases		
		Rate
Year	PUB Order	Increaase %
2014/15	Order 49/14	2.75
2015/16	Order 73/15	3.95
2016/17	Order 56/19	3.36
2017/18	Order 80/17	3.36
2018/19	Order 59/18	3.60
Average 2014/15 to 2018/19 - last 5 years		**3.40**
Average 2015/16 to 2018/19 - last 4 years		**3.57**
Average 2016/17 to 2018/19 - last 3 years		**3.44**

MH's assertion that the 3.5% proposed rate increase for 2019/20 is aligned with PUB-approved rate increases since 2015 is correct. While it is not specifically known if MH was including the rate increase for 2014/15 in its calculation or not, the PUB-approved electric rate increases in the last four to five years do produce a simple average of approximately 3.4% to 3.6%.

The 3.5% proposed rate increase for 2019/20 is also consistent with the 3.57% indicative rate increase included in MH Exhibit #93.

In Order 59/18, the PUB rejected the 7.9% rate path that was proposed in the last GRA, indicating on pages 172, 62 and 163 of that decision that:

> "Manitoba Hydro's request for an April 1, 2018 rate increase of 7.9% is denied. The **Board finds that Manitoba Hydro has not met its onus** of **proving that a 7.9% rate increase is just and reasonable.**"
>
> "…the Board finds that **raising consumer rates by an amount equivalent to four times the rate of inflation** is **not required to support Manitoba Hydro's current operations**."
>
> "…the **Board determines** that **principles of rate stability and predictability are important for residential ratepayers, industry,**

business and community organizations. The **Board further finds** that the **rate increase sought by Manitoba Hydro for the Test Year departs from these principles**." (Emphasis added)

While the change in the expected implementation date to June 1, 2019 has resulted in a decrease in the revenue that will be generated in the 2019/20 fiscal year to $50 million, the proposed 3.5% rate increase would generate an additional $59 million of revenue per year on an annualized basis in perpetuity.

The impact of the 3.5% proposed rate increase is significant to customers. Assuming a 5% social discount rate, MH has calculated that the present value of the proposed rate increase in perpetuity for all customer classes is in the order of $1.4 billion (range of $1.3 to 1.5 billion) and the present value for the residential customers is in the order of $600 million (response to Coalition/MH I-5).

One key observation surrounding the rather simplistic calculation presented above, is that in comparison to the most recent PUB-approved electric rate increases, the 3.5% proposed rate increase for 2019/20 should not be viewed as inconsequential, a compromise or a half-measure in comparison to the 7.9% proposed and indicative rate increases included in MH16 and requested at the last GRA. The 3.5% proposed rate increase should be considered by MH and the PUB to be a significant rate increase.

6.2. Alignment of the Proposed Rate Increase with Past Approved Rate Increases and Exhibit #93 Indicative Rate Increases are Observations not a Justification for the Proposed Rate Increase

It is a commonly established regulatory requirement that MH as the applicant in this proceeding has the onus of proof to prove to the PUB that its rate proposals are just and reasonable and within the public interest.

There is no reverse onus on the PUB or Intervenors to disprove the reasonableness of the MH proposed rate increase.

MH's strict reliance on Exhibit #93 as the benchmark for the appropriate level of rate increase in 2019/20 is somewhat concerning. MH normally includes the

following disclaimer (IFF16 page 8) in its IFF documents as it relates to indicative rate increases that are included in IFF's for the years after the proposed rate increases for the test year(s):

> "**Proposed rate increases subsequent to 2018/19 are subject to change in future forecasts**. Each year's revision to the IFF is based on the current year's assumptions including energy supply and demand, projected interest, escalation and exchange rates, projected prices for exported energy, operating and capital forecasts, and other factors. Changes in any of these assumptions will have an impact on the projected future results. **Actual rate applications made in the future years will depend upon circumstances and outlook at that time** and will be **subject to review and approval of the MHEB**." (Emphasis added)

It is understood that the PUB's approval of a particular rate increase in a test year based on a financial scenario with a particular progression of indicative rate increases does not bind a future PUB panel to follow that same financial scenario, rate strategy or progression of indicative rate increases for future rate changes. This is no different than the understanding that the inclusion of future indicative rate increases in an IFF does not bind a future MHEB to follow the same rate strategy or progression of indicative rate increases for future rate applications. Simply stated, the PUB outlining the consistency of a financial scenario with its current year rate determination does not constitute any form of "pre-approval" of a particular progression of indicative rate increases, in the years after the proposed rate application.

Perhaps it is trite to state, but MH's observation that the 3.5% proposed rate increase is consistent with prior PUB-approved rate increases, is just that, an observation. Such an observation does not constitute a justification for a rate increase which should be based on an assessment of the updated projected revenue requirements of MH's in the test year and balancing the financial integrity of MH with the impacts on customers.

6.3. Jurisdictional Rate Comparisons provide Context but are Not a Justification for the Proposed Rate Increase

In section 3.2 of MH's original application, MH provides a number of comparisons of Manitoba Electricity rates to neighboring jurisdictions:

1. Figure 3.2 – a comparison of average electricity prices in major Canadian cities for rates in effect April 1, 2018, concluding that the average price per kWh paid by Manitobans is amongst the lowest in large Canadian cities;
2. Figure 3.3 - a summary of rate changes/cumulative rate changes from utilities across Canada (MH, BC Hydro, SaskPower, NB Power, NS Power and Toronto Hydro) from 2007 to 2019 and a current rate index of the average price per kWh for the various utilities. There are no conclusions made by MH with respect to this summary but it is noted that the current rate index for the other utilities where data is available is between 109% and 171% higher than MH and that MH has lower cumulative rate increases over this period than BC Hydro and SaskPower and higher cumulative rate increases over this period than Hydro Quebec, NB Power, NS Power and Toronto Hydro;
3. Figures 3.4 to 3.8 – monthly bill comparisons for residential, small power, medium power and Large Power users at various levels of consumption for major Canadian cities for 2019/20. These comparisons appear to demonstrate that Winnipeg compares favorably with other Canadian cities and generally is either the lowest monthly bill or second lowest to Montreal. MH notes that where published information on projected rate increases are not available it has made a simplifying assumption that annual rate increases will be in line with inflation at 2% each year but does not specify when this simplifying assumption has been used in the analysis; and
4. Figure 3.9 - comparison of average retail electricity prices for a number of low-cost and neighboring jurisdictions in Canada and the US – indicating that MH's average retail electricity price is the lowest in all of the jurisdictions that are cited.

At the end of section 3.2 of the original application, MH makes the overall observation that the figures in the section demonstrate that Manitoba continues to maintain an advantage over most North American Jurisdictions with respect to the average monthly customer bills and average prices for all customer classes.

In terms of an assessment of these jurisdictional comparisons, consistent with the conclusions outlined in Section 6.2 above, these comparisons provide some contextual information but are of questionable value for rate-setting purposes in that they are based on readily available information with simplifying assumptions such as inflationary rate increases and are not a complete survey of the Canadian utility landscape and do not constitute justification for the proposed 3.5% rate increase.

6.4. Jurisdictional Rate Comparisons Do Not Meet the PUB Expectations from Order 59/18 to Assess the Broader Impacts of Proposed Rate Increases

MH's jurisdictional rate comparisons are similar in nature to information that has been provided at past MH rate hearings.

In Order 59/18, the PUB made the following findings at pages 172 and 217 to 218:

> "The **Board finds that Manitoba Hydro failed to present economic impacts of the 7.9% rate increase or the impact on customers in various sectors** – such as residential, commercial, and industrial. **In future rate applications, the Utility is to assess the broader impacts of the rate increases beyond only the financial health of Manitoba Hydro**"
>
> "…this requires the **Board to balance two concerns: "the interests of the utility's ratepayers, and the financial health of the utility**. Together, and in the broadest interpretation, **these interests represent the general public interest**." **Each of these two concerns** support the **ability of the Board to consider the affordability of Manitoba Hydro's rates** whether broadly or within a class or sub-set of its customers.

> **Affordability is not only relevant to the interests of the Utility's ratepayer, but also to the financial health of the Utility** as rates that are in excess of what customers can afford may lead to depressed revenues through a combination of reduced energy consumption, business closures or relocation, and as acknowledged by Manitoba Hydro, potentially an increase in arrears." (Emphasis added)

In the response to Coalition/MH I-2, MH indicates that it has not conducted a neighboring jurisdictional analysis that includes household income, rate of poverty or energy cost as a proportion of household income or expenditure.

In the response to Coalition/MH I-4 b, MH takes the position that the assessment or consideration of any macroeconomic impacts of a proposed rate increase on the Provincial economy goes far beyond the balancing of interests of ratepayers and the utility and into the realm of government and is not contemplated as a factor to be considered in the Manitoba legislation pertaining to establishing just and reasonable rates for utility service.

While the MH response to the above noted PUB findings may be a matter for more detailed examination at the next comprehensive GRA, they underscore that MH's analysis of customer bills and average prices for customers is limited and does not address the PUB concerns expressed in Order 59/18 with respect to economic impacts and bill affordability for customers.

7.0 MH's Updated Projections for 2019/20 Do Not Support the Need for a 3.5% Rate Increase

The overall conclusion from the assessment of the first three MH reasons for the proposed rate increase is that none of these reasons support the PUB approval of a 3.5% rate increase in 2019/20, which can be summarized as follows:

1. There is no material deterioration in MH's Financial position since the last GRA to justify the proposed 3.5% rate increase;
2. The PUB has no adequate evidence to conclude that there will be an exacerbation of losses after the in-service of the Keeyask generating station that will increase the likelihood of future rate shock; and
3. Observations with respect to the level of past rate increases or jurisdictional rate comparisons are not valid justifications for the proposed rate increase.

As was summarized in Section 3.0, the remaining reasons from the original application were as follows:

1. Without the proposed rate increase, MH was projecting a net loss of $28 million for Electric operations for 2019/20. The 3.5% proposed rate increase (effective April 1, 2019) was projected to generate additional revenues of $59 million and provide a modest contribution to financial reserves (net income) of $31 million in 2019/20; and
2. Without the proposed 3.5% rate increase, the likelihood of financial losses is greater as MH's net income has historically been extremely volatile with the key drivers of net income (water flow, weather, interest rates and export prices) being unpredictable and outside of MH's control. The proposed 3.5% rate increase would reduce the risk of MH incurring a loss in 2019/20.

Now that the update to MH's rate application is projecting 2019/20 net income without the proposed rate increase of $64 million, which is $33 million higher than the original application with the proposed rate increase, MH has adjusted its reason for the application to be:

The proposed 3.5% rate increase **continues** to allow MH to plan for a modest level of net income in the event of low water flow conditions or the occurrence of other negative financial events that are unpredictable and outside of MH's control and reduces the likelihood of future rate shock to ratepayers that could result from a financial loss in 2019/20.

The remainder of this portion of the analysis will follow a relatively sequential process to consider the need for and appropriate level of any rate change for 2019/20:

1. Assess forecasts of projected revenues and expenses and key financial metrics before any rate increase is considered (Section 7.0);
2. Assess if MH has appropriately managed costs for those financial levers that are within its control in order to mitigate the need for rate increases from customers (Section 8.0); and
3. Consider the balancing of the financial integrity and risks of the utility with the rate impacts on customers (Section 9.0).

Section 10.0 of the evidence will summarize the conclusions and provide recommendations to the PUB based on the evaluation of the evidence.

This section will analyze this MH reason for application (achievement of a modest net income for 2019/20) from the following perspectives:

1. How do the projections for 2019/20 in the updated application compare to the financial objectives (net income) of MH from the original application and the expectations from the last GRA;
2. What is the appropriate perspective with respect to net income for 2019/20 when considering MH's operations and the in-service of Bipole III; and
3. Is the proposed 3.5% rate increase for 2019/20 supported by any quantifiable financial objective (net income) or financial metric (financial targets).

The following schedule summarizes MH's projected revenues, expenses, net income and financial ratios for 2019/20 and provides a comparison of the

updated application (without the proposed rate increase), original application (without the proposed rate increase), MH Exhibit #93 adjusted for a 20-year WATM (with an indicative 3.57% rate increase) and MH Exhibit #93 (with an indicative 3.57% rate increase):

Figure 11 - Comparison of Projected Net Income & Financial Ratios				
	Updated Application	**Original Application**	**Exhibit 93 Adjusted**	**Exhibit 93**
	1	**2**	**3**	**4**
Domestic & Other Revenue - without rate increase	1726	1707	1693	1693
BPIII Reserve Account	78	78	79	79
Net Extraprovincial Revenues	174	140	152	152
Total Net Revenues	**1978**	**1925**	**1924**	**1924**
Operating & Administrative	511	511	511	511
Net Finance Expense	742	766	755	722
Depreciation & Amortization	505	508	515	515
Capital & Other Taxes	148	150	154	154
Other Expenses	74	111	481	481
Corporate Application	8	8	8	8
Net Movement in Regulatory Deferrals	-71	-103	-473	-473
Non-controlling Interest	-4	2	2	2
Total Net Expenses	**1913**	**1953**	**1953**	**1920**
Net Income -Without Rate Increases	**65**	**-28**	**-29**	**4**
Proposed Rate Increase	50	59	57	57
Net Income - With Rate Increases	**115**	**31**	**28**	**61**
Financial Ratios - without 3.5% Proposed Rate Increase:				
Equity Ratio	13.03%	12.47%		
Interest Coverage Ratio	1.56	1.47		
Capital Coverage Ratio	1.24	0.97		
Financial Ratios - with 3.57% Indicative Rate Increase:				
Equity Ratio			13.37%	13.58%
Interest Coverage Ratio			1.53	1.58
Capital Coverage Ratio			1.12	1.18
Sources:				
Column 1 - Figure 7 - Updated Application				
Column 2 - Figure 2.9 - Original Application				
Column 3 - Figure 2.5 - Original Application - adjusted for 20 Year WATM by increaseing finance expense by $33m				
Column 4 - Figure 2.5 - Original Application				

The summary observations from this schedule are discussed in the following sub-sections of Section 7.0.

7.1. The Updated 2019/20 Net Income of $64 Million Without the Proposed Rate Increase Exceeds MH's Original Financial Objective of a Modest Net Income of $31 Million

In the original application, MH proposed the 3.5% rate increase in order to mitigate the projected loss of $28 million that was forecast at the time and generate sufficient revenues to project a modest net income of $31 million for 2019/20.

In making the original application, MH was essentially specifying what it believed was a reasonable financial objective for 2019/20 (modest net income of $31 million) under the circumstances.

In the updated application, the net income for 2019/20 (without the proposed 3.5% rate increase) is now projected at $64 million. This is $33 million in excess of the projected modest net income of $31 million (including the proposed rate increase) from the original rate application.

If the proposed 3.5% rate increases is approved by the PUB, MH's projected net income for 2019/20 of $115 million would be $84 million higher than the financial objective of $31 million specified by MH in the original application.

7.2. The Updated 2019/20 Net Income of $64 Million Without the Proposed Rate Increase Exceeds the Net Income Projected in MH Exhibit #93 Adjusted for the 20-Year WATM of $28 Million

The projected net income for 2019/20 in MH Exhibit #93 adjusted for the 20-Year WATM (including the indicative 3.57% rate increase) was $28 million.

In the updated application, the projected net income for 2019/20 (without the proposed 3.5% rate increase) of $64 million, exceeds the net income projected in the adjusted MH Exhibit #93 (including the indicative 3.57% rate increases) by $36 million.

If the proposed 3.5% rate increases is approved by the PUB, MH's projected net income for 2019/20 of $115 million would $87 million higher than the adjusted net income expected in the last GRA.

7.3. A Reasonable Financial Objective for 2019/20 Should Consider the Impacts of a Large Asset Like Bipole III Coming Into Service In the Previous Fiscal Year

In assessing a reasonable financial objective for 2019/20 (in terms of net income), it is important to consider the PUB's findings from pages 61 to 62 of Order 59/18 (provided in Section 4.3) that the assessment of rate increases must consider the circumstances of Manitoba Hydro's operations – large upfront construction costs, relatively low operating costs and a very long useful lives.

Given the lumpy nature of the major capital projects and an historic MCOS approach to rate-setting that spreads the costs of these large projects over long periods of time to recognize the period over which benefits are provided to customers, it is not an unusual expectation that there may be financial losses in the initial years when these projects enter service (and the finance and depreciation costs begin to be recognized in the income statement and by extension, revenue requirement).

The actual Electric net plant in service as at March 31, 2018 was $12.380 billion as per Appendix 1 of the updated application. The addition of Bipole III at $4.77 billion in the 2018/19 fiscal year represents a substantial increase (approximately 39%) in the net plant in service for MH. While there are caveats in using incremental revenue requirement calculations for major capital projects (see Section 5.2 of this Evidence), the 2019/20 incremental revenue requirements for Bipole III from the updated response to PUB/MH I-9 are in the order of $280 million for 2019/20 or approximately 16.5% of revenue at existing rates of $1.699 billion in Appendix 1 (updated).

The fact that MH is projecting a net income in 2019/20 of $64 million (without the proposed rate increase) during the first full year that Bipole III is in-service is not

an unfavorable circumstance considering the significant impacts of this asset on the balance sheet and income statement of MH.

7.4. Updated Financial Ratios for 2019/20 (Without the Proposed Rate Increase) are Consistent with MH Exhibit #93 Adjusted for the 20-Year WATM

As outlined in Figures 6 and 11 – the projected financial ratios for 2019/20 in the updated application (without the proposed rate increase) are consistent with those of the adjusted MH Exhibit #93:

- The projected Equity ratio in the updated application (without the proposed rate increase) is 13.03% compared to 13.37% in the adjusted MH Exhibit #93 calculation (with the indicative 3.57% rate increase). The Equity ratio in the updated application (without the proposed rate increase) is 13.36% (Figure 6) when holding the unrealized AOCI losses constant;
- The projected Interest Coverage ratio in the updated application (without the proposed rate increase) is 1.56 compared to 1.53 in the adjusted MH Exhibit #93 (with the indicative 3.57% rate increase); and
- The projected Capital Coverage ratio in the updated application (without the proposed rate increase) is 1.24 compared to 1.12 in the adjusted MH Exhibit #93 (with the indicative 3.57% rate increase).

The projected financial ratios for MH, do not support the need for a 3.5% rate increase in 2019/20. The projected financial ratios in the updated application without a rate increase are consistent with those forecast at the last GRA with the indicative 3.57% increase.

7.5. The Proposed 3.5% Rate Increase for 2019/20 Has Not Been Justified by Any Quantifiable Financial Objective or Financial Metric

The projected net income for 2019/20 of $115 million is simply the original rate increase proposal adjusted for an expected June 1, 2019 implementation date ($50 million additional revenue in 2019/20) and added to a significantly improved financial outlook for the fiscal year (projected net income of $64 million without the proposed rate increase).

The overall conclusion from this section of the evidence is that MH has not justified the continued request for a 3.5% rate increase in 2019/20 based on any quantifiable financial objective (net income) or financial metric (financial ratios).

8.0 MH Has Not Adequately Responded to the PUB's Findings from Order 59/18 to Reduce Controllable Costs in an Era of Major Capital Projects with the Associated Rate Pressures

One of MH's key messages in its application is that its net income has historically been extremely volatile with the key drivers of net income being unpredictable and outside of MH's control.

This section will analyze this MH reason for application (key drivers of net income are unpredictable and outside of MH's control) from the following perspectives:

1. What were the PUB findings in Order 59/18 with respect to the expectations for MH to exercise restraint over costs that are controllable;
2. Does MH's forecasts of controllable costs adhere to the PUB findings and recommendations from Order 59/18;
3. Is it reasonable that MH has no detailed forecasts of O&A to support close to 30% of the requested revenue requirement in 2019/20; and
4. Are there adjustments that should be made to MH's 2019/20 projections for the purposes of rate-setting.

All of the risk sensitivities provided by MH in the original application (Figure 2.10) relate to variables that are largely outside of the control of MH (water flow, weather, interest rates and export prices). MH did not provide any risk sensitivities related to its controllable expenditures for Business Operations Capital (BOC), Demand Side Management (DSM) expenditures and Operating & Administrative Costs (O&A), which totaled approximately $1.116 billion for 2019/20 in the original application (BOC = $511 million, DSM = $94 million and O&A = $511 million).

When questioned by the PUB and Intervenors with respect to reductions to conform with the PUB findings and recommendations in Order 59/18 – the general response in the information requests was that there could be impacts to safe and reliable service (BOC and O&A) and that DSM spending is consistent with a status quo approach directed by the Province of Manitoba.

When reviewed in their totality, it is evident that MH's forecasts in the updated application are inconsistent with the PUB's rate-setting findings and recommendations in Order 59/18 with respect to MH's controllable costs. While each of these areas (BOC, DSM, O&A) will be assessed separately in Sections 8.1, 8.2, 8.3 and 8.4, it is readily apparent that the PUB is concerned about the pressure on the financial outlook and rates as a result of the major capital projects (Bipole III and Keeyask in particular) and found through the detailed assessment at the last GRA that MH must takes steps to reduce controllable expenditures and alleviate pressure on rates in the era of major capital projects.

While there have been reductions to BOC and DSM spending in the updated application (O&A spending remained constant) for 2019/20, a review of the evidence indicates that these have more to do with delays in execution (contractor delays, customer project deferrals, resource constraints etc.) with respect to BOC adjustments and directions from the Province (to maintain a status quo before the transition to Efficiency Manitoba) in the case of DSM.

The total expenditure reductions in the updated application for 2019/20 are approximately $66 million (BOC = $33 million and DSM = $33 million) which is approximately 5.9% of the original budget for controllable costs of $1.116 billion. In addition, these adjustments do not reflect a response to the PUB's findings and recommendations, but rather, are short-term reductions for the 2019/20 fiscal year that do not result in reduced controllable expenditures over the longer-term.

As a general observation, the PUB and stakeholders should be concerned about MH's position with respect to the inability to curtail controllable spending and the lack of response by MH to the findings and recommendations of the PUB in this regard.

8.1. BOC Reductions of $37 Million in 2018/19 & $33 Million in 2019/20 Are Largely Related to Normal Operational Execution Risks and Not Improved Asset Management Practices by MH

The PUB made a number of rate-setting findings with respect to BOC in Order 59/18 pages 110 to 113, which can be summarized as follows:

> "The **Board finds** that, while in **a period of major capital spending** on Keeyask and Bipole III, **Manitoba Hydro should find savings in Business Operations Capital**…The **Board does not accept the Business Operations Capital Spending forecast in Capital Expenditure Forecast CEF16**..The **Board finds that Business Operations Capital Spending can be safely decreased by $160 million** based on Manitoba Hydro's evidence that it can defer $160 million of spending in the Test Year…**The Board accepts the METSCO's evidence that Manitoba Hydro cannot demonstrate the proposed spending is necessary or has been optimized to any extent**…it does recognize the cost pressures that result from the capital program that includes Bipole III, Keeyask, and a new interconnection with the U.S. Those **cost pressures mean** that **Manitoba Hydro can no longer continue to fund Business Operations Capital at its historic levels** unless and until it can demonstrate through mature asset management processes that those investments are necessary." (Emphasis added)

The PUB made the following recommendations to MH with respect to BOC in Order 59/18 on page 264, which are as follows:

> "**1. Defer $160 million of Business Operations Capital spending** to a future period beyond 2018/19…**2. Continue to find reductions in Business Operations Capital spending during the current period of record spending on major capital projects** such as Keeyask and Bipole III."

The following schedule provides a summary of actual and projected BOC spending for the five-year period of 2013/14 to 2017/18 as well as the original and updated BOC spending for 2018/19 and 2019/20:

Figure 12 - Business Operations Capital (BOC) Analysis 2013/14 to 2019/20							
	2013/14	2014/15	2015/16	2016/17	2017/18	Total	Average
BOC Historic Performance:	1	2	3	4	5	6	7
BOC Actual	470	524	533	530	461	2518	504
BOC Budget	526	571	577	574	526	2774	555
Variance	**-56**	**-47**	**-44**	**-44**	**-65**	**-256**	**-51**
Variance %	**-10.7%**	**-8.2%**	**-7.6%**	**-7.7%**	**-12.4%**	**-9.2%**	**-9.2%**
						2018/19	2019/20
BOC Forecast for 2018/19 & 2019/20						8	9
BOC Updated Application						478	478
BOC Original Application						515	511
Variance						**-37**	**-33**
Variance %						**-7.2%**	**-6.5%**
Sources:							
Column 1 to 5 - response to Coalition/MH 30 c							
Column 8 to 9 - Figure 8 Updated Application							

The key observations from Figure 12 with respect to BOC spending are as follows:

1. Over the five-year period from 2013/14 to 2017/18, the BOC underspending in a particular year ranged between $44 million (2015/16 & 2016/17) and $65 million (2017/18) and 7.6% and 12.4% of the total forecast expenditures;
2. In the most recent fiscal year (2017/18), BOC was underspent by $65 million on a forecast of $526 million, a 12.4% variance from the forecast;
3. Over the five-year period from 2013/14 to 2017/18, the average actual BOC spending for a year was $504 million compared to an average forecast of $555 million, with the underspending averaging approximately $51 million per year or 9.2%; and

4. For the 2018/19 and 2019/20 fiscal years the original budgets have been reduced in the updated application by $37 million and $33 million respectively, or a reduction of 7.2% and 6.5%, respectively.

The scope of this regulatory proceeding did not include a detailed review of MH's BOC expenditures. However, on pages 14 and 15 of the updated application, MH attributed the reductions in the BOC budget to:

> "a **review of various projects** using the **Corporate Value Framework** to optimize the timing of investments to **achieve the best value with available resources**. **In addition**, various projects were impacted by **contractor delivery delays, customer project deferrals** as well as **project completions without the requirement for contingency forecasts** for unforeseen risks." (Emphasis added)

In the response to Coalition/MH I-30 f, MH made the following observations with respect its BOC capital spending:

> "The BOC target for the year is the aggregation of the cash flows for all of the investments occurring in the 12 months of the fiscal year, which comprise hundreds of projects and thousands of program items and district work orders…However, **cash flows are subject to considerable uncertainty due to execution risks** manifesting as schedule and budget variances…**Execution risks impacting schedule are heavily skewed to delaying rather than advancing progress, resulting in the propensity to underspend** planned annual cash flow targets as work is pushed out of the current fiscal year." (Emphasis added)

Based on the limited scope of the BOC review in this regulatory proceeding and the MH responses to information requests, it is reasonable to conclude that the reductions in the BOC forecast for 2018/19 and 2019/20 are a function of normal operational execution risks and resource constraints (particularly as a result of the VDP) and not a response by MH to the rate-setting findings and recommendations of the PUB with respect to BOC.

It is noted in the response to Coalition/MH I-6 h, that actual BOC spending to December 31, 2018 was $334 million compared to the CEF18 forecast of $409 million for an underspending of $76 million or 18% for the first nine-months of the 2018/19 fiscal year. MH did not indicate in this response if it expects that level of underspending to continue to the end of the fiscal year.

Based on past trends of BOC underspending in the prior five-year period (average 9.2%) and in the most recent fiscal year (12.4%), it would be reasonable for the PUB to consider further reductions to BOC for rate-setting purposes for the 2019/20 fiscal year as follows:

- 2018/19 rate-setting adjustment = $10 million (($515*.092)-$37) to $27 million (($515*.124)-$37); and
- 2019/20 rate-setting adjustment = $14 million (($511*.092)-$33) to $30 million (($511*.124)-$33).

8.2. DSM Reductions of $33 Million in 2019/20 Reflects a Status Quo Approach Directed by the Province and Not a Review of the Cost Effectiveness of DSM Programming by MH

The PUB made a number of rate-setting findings with respect to DSM in Order 59/18 pages 118 to 122, which can be summarized as follows:

> "The **Board finds** that Manitoba Hydro's **revenue requirement should be reduced** to **reflect lower demand side management spending** as a result of the **new lower marginal value**…Considerations other than the reasonableness of expenditures for rate-setting purposes will apply once Efficiency Manitoba has assumed demand side management programming and presents a demand side management plan to the Board for review…Efficiency Manitoba is not yet operational and once it is, there are legislated steps that must occur prior to the entity's implementation of an approved efficiency plan…**The adverse rate impacts that arise from Manitoba Hydro's plan are not reasonable in the present context**…**Reduced demand side management spending for rate-setting purposes is supported by the change in circumstances since**

> **the NFAT review in 2014**…the next next generation resource is not needed until approximately 2040…The 2017 marginal value is lower than the 2013 marginal value by approximately one-third…rate increases above inflation will themselves have a conservation impact…The **Board finds** that, **in light of the new, lower, levelized marginal value**, **some of Manitoba Hydro's demand side management programming may no longer be cost effective**…**In light of the above, the Board recommends that Manitoba Hydro reduce its demand side management spending**…Manitoba Hydro should **review its demand side management programming for cost effectiveness** and cease or modify spending on programs that are no longer cost effective, **except for programs targeted at lower-income and First Nations on-reserve customers.**" (Emphasis added)

The PUB made the following recommendation to MH with respect to DSM in Order 59/18 on page 265, as follows:

> "**9. Review demand side management programming for cost effectiveness** and cease or **modify spending on programs** that are **no longer cost effective**, **except for programs targeted at lower-income and First Nations on-reserve consumers**." (Emphasis added)

The following schedule provides a summary of actual and projected DSM spending for the five-year period of 2013/14 to 2017/18 as well as the original and updated DSM spending for 2018/19 and 2019/20:

Figure 13 - Demand Side Management Expenditures (DSM) Analysis 2013/14 to 2019/20							
	2013/14	2014/15	2015/16	2016/17	2017/18	Total	Average
DSM Historic Performance:	1	2	3	4	5	6	7
DSM Actual	26	34	55	51	64	230	46
DSM Budget	35	53	63	57	58	266	53
Variance	**-9**	**-19**	**-8**	**-6**	**6**	**-36**	**-7**
Variance %	**-25.7%**	**-35.9%**	**-12.7%**	**-10.5%**	**10.3%**	**-13.5%**	**-13.2%**
						2018/19	2019/20
DSM Forecast for 2018/19 & 2019/20						8	9
DSM Updated Application						63	61
DSM Original Application						63	94
Variance						**0**	**-33**
Variance %						**0.0%**	**-35.1%**
Sources:							
Column 1 to 5 - response to Coalition/MH 17 a b							
Column 8 to 9- Figure 8 Updated Application							

The key observations from Figure 13 with respect to DSM spending are as follows:

1. Over the five-year period from 2013/14 to 2017/18, the DSM underspending in a particular year ranged between $6 million (2016/17) and $19 million (2014/15) and 10.5% and 35.9% of the total forecast expenditures;
2. In the most recent fiscal year (2017/18), DSM was overspent by $6 million on a forecast of $58 million, a 10.3% variance from the forecast;
3. Over the five-year period from 2013/14 to 2017/18, the average actual DSM spending for a year was $46 million compared to an average forecast of $53 million, with the underspending averaging approximately $7 million per year or 13.2%; and
4. For the 2018/19 the budgeted DSM expenditures remain at $63 million which is consistent with the budget included in the original application; and

5. For the 2019/20 fiscal year the original DSM budget has been reduced in the updated application from $94 million to $61 million, or a reduction of $33 million or 35.1%.

The scope of this regulatory proceeding did not include a detailed review of MH's DSM expenditures. However, on page 15 of the updated application, MH indicated the following:

> "The **2019/20 DSM plan reflects the continuation of current DSM program offerings** while **responsibility for DSM transitions to Efficiency Manitoba**. Manitoba Hydro is currently in consultations with the Province as required under the *Energy Saving Act* with the 2019/20 DSM plan expected to be finalized in Spring 2019 following final consultations with the Province." (Emphasis added)

In the response to Coalition/MH I-33 b, MH made the following observations with respect to the 2019/20 adjustments to its DSM spending:

> "**Manitoba Hydro has been directed by the Province to maintain a status quo approach to DSM with no new program offerings**. Based upon this direction, the **forecasted savings and budgets** for the future **Conservation Rates initiatives** and **Fuel Choice program have been removed** and **adjustments have been made to existing program forecasts based on current market information** in the development of the 2019/20 1 year DSM plan. The resulting 2019/20 Approved DSM Budget has been reduced to $61 million, as outlined on pages 14 and 15 of the Supplement to the 2019/20 Electric Rate Application." (Emphasis added)

Based on the DSM review in this regulatory proceeding and the MH responses to information requests, it is reasonable to conclude that the reduction in the DSM budget for 2019/20 is based primarily on the status quo approach directed by the Province and not a response by MH to the rate-setting findings and

recommendations of the PUB with respect to reviewing the cost effectiveness of DSM programming.

It is noted in the response to Coalition/MH I-6 h, that actual DSM spending to December 31, 2018 was $53 million compared to the CEF18 forecast of $41 million for an overspending of $12 million or 28% for the first nine-months of the 2018/19 fiscal year. MH indicated in this response that no material variance is expected for DSM spending to March 31, 2019.

The limited record of this proceeding, including the recent DSM spending levels would tend to indicate that there is no expectation of a material variance in DSM spending for 2018/19 and 2019/20.

It would be reasonable for the PUB to consider reductions to DSM for rate-setting purposes based on the findings in Order 59/18. However, there is no evidence on the record to make a quantitative adjustment for DSM programs that may no longer be cost effective.

8.3. The $511 Million O&A Budget for 2019/20 which Represents 29% of the Requested Revenue Requirement Is Based on a High-Level and Outdated Target Calculation from 2017

MH did not provide any information on the setting of O&A targets in its original application, simply noting on page 28 of the original application that:

> "**Consistent with Exhibit 93**, **Manitoba Hydro's preliminary O&A target** included in the 2019/20 Interim Budget is **$511 million** reflecting an **inflationary increase of 2%** over the $**501 million** of O&A expenses included **in the 2018/19 Financial Outlook**. The **2% increase is aligned with Manitoba CPI**. **Manitoba Hydro** is committed to achieving this level of O&A expenditure and **is in the process of developing detailed budgets for 2019/20** to support this commitment…A **total of 821 employees were approved under the VDP** with the **majority of the staff departing by March 2018.**" (Emphasis added)

The projected O&A costs was the only line item in the projected revenue requirements for 2018/19 and 2019/20 that was not adjusted in the updated application filed on February 14, 2019 (other than the Bipole III reserve account - see Figure 3 in the updated application).

The last time that the detailed O&A budgets were reviewed by the PUB in a comprehensive oral hearing process was part of the 2014/15 & 2015/16 GRA in May and June of 2015, almost four years ago.

The O&A target of $511 million for 2019/20 represents approximately 29% ($511/$1,749) of the domestic revenue requirement that the PUB is being requested to approve in the application (see Figure 7 of the updated application) and is not supported by any information other than a high-level target calculation that was included in MH 16 (Updated) that was finalized by MH in April 2017 (Appendix 3.1 from the last GRA). The high-level O&A targets of $501 million for 2018/19 and $511 million for 2019/20 are approximately two-years old and were developed by MH before the VDP transition began.

The main support that was provided by MH for the O&A targets at the 2017/18 & 2018/19 GRA was an undertaking by MH which was filed as Exhibit #78 at the last GRA. Exhibit #78 from the last GRA provided two analysis, a high-level O&A target calculation for 2017/18 and 2018/19 from MH16 and an updated calculation based on the post VDP program results. Both calculations essentially produced identical O&A forecasts for these two fiscal years. For 2018/19, the second calculation increased the labor savings from staff reductions as a result of the VDP by approximately $12 million but added in an equal and offsetting provision of $12 million to address potential restructuring costs/transitional business requirements.

It appears from a review of Exhibit #78 that this $12 million provision for potential restructuring costs/transitional business requirements was simply a contingency amount or “plug” to maintain the $501 million O&A forecast for 2018/19.

It is concerning that the O&A forecasts for 2018/19 and 2019/20 remain at $501 million and $511 million, respectively. One would expect with a corporation the size of Manitoba Hydro and all the complex variables that can impact O&A, including a significant VDP, that there would be changes in forecast O&A from that which was forecast two years ago in MH16. As such, it is not known if the O&A target analysis can be relied upon for rate-setting purposes or if contingency provisions are being included in the underlying assumptions that are designed to maintain O&A forecasts at the same amounts from MH16.

The historical O&A variance analysis from 2013/14 to 2017/18 which was provided in the response to Coalition/MH I-14 e, does not provide assurance in terms of the reliability of the O&A targets for rate-setting purposes for 2019/20. In this information request, MH concludes that its O&A performance has been within 1% of its approved forecast over the last five fiscal years. The difficulty is that assertion is based on comparing O&A forecasts that were developed close to the start of the fiscal year with the actual O&A costs in that same fiscal year. The issue for this regulatory proceeding is how accurate are O&A forecasts that were originally developed in early 2017 for the 2019/20 fiscal year.

As an example, the Electric O&A forecast that was developed in MH13 for the second year of that forecast (2014/15) was $494 million. In MH14, the Electric O&A forecast for 2014/15 (now the first year in the forecast) was revised downward to $486 million, a reduction of $8 million or 1.6%. Actual Electric O&A was $481 million for 2014/15. The variance between the actual 2014/15 O&A and MH13 forecast (that was developed late in 2013) was $13 million or 2.6% underspent. The variance between the actual 2014/15 O&A and MH14 forecast (that was developed late in 2014) was $5 million or 1.0% underspent.

The numerous adjustments related to the transition to IFRS in 2014/15 and 2015/16 makes further comparisons of this nature with other IFF's and other fiscal years very complex and nearly impossible based on the limited record of this proceeding. However, the principle is demonstrated that high-level O&A

targets developed two years prior to the test year may not be reliable for rate-setting purposes.

The O&A variance analysis to December 31, 2018 which was provided in the updated response to PUB/MH I-15, does not provide assurance in terms of the reliability of the O&A targets for rate-setting purposes for 2019/20. According to this analysis, O&A expenses are overspent by approximately $2.0 million or 0.5% (on a total forecast of $376 million) for the first nine-months of 2018/19. However, a closer examination of this analysis demonstrates that the reason for the unfavorable variance is a result of lower than forecast capitalized labor and benefits of approximately $24.1 million (9.8% variance) for the first nine-months of the year. Total employee related expenditures are $12.9 million underspent (2.3% variance), external services and materials are $3.2 million underspent (3.3% variance) and other operating costs are $5.1 million underspent (74.5% variance) for the first nine-months of the year. The relatively small overall net variance of 0.5% at December 31, 2018 is not a result of accurate forecasting but rather simply the outcome of the netting of a number of much more significant favorable and unfavorable variances.

Therefore, the conclusion from this analysis is that are significant concerns that the O&A target for 2019/20 is outdated and is not reliable for rate-setting purposes.

It is challenging to understand why MH has not yet been able develop a detailed O&A budget approximately 12 months after the completion of the VDP. All of the detailed budgets that form the components of an IFF (i.e., net export revenue or finance expense) are based on the best information that is available at a point in time and are subject to operational changes or external factors/events that will inevitably result in variances. Each of these component budgets has numerous complexities such that there will never be perfect certainty in the resulting budget. O&A is no different and represents close to 30% of the revenue requirement of MH. In fact, it could be argued that O&A should be easier to forecast as it primarily relates to internal resources under the control of MH.

The PUB has been quite pragmatic in approving revenue requirements for 2017/18 and 2018/19 without the benefit of detailed O&A budgets. Given the materiality of this expenditure and Hydro's failure to provide detailed O&A budgets, it is recommended that the PUB direct MH to develop and file a detailed O&A budget at the earliest possible time to ensure the integrity of the rate-setting process and the accountability of a public sector crown like MH.

8.4. The $511 Million O&A Budget for 2019/20 Should Be Reduced for Rate-Setting Purposes by $22 Million to $489 Million

The PUB made the following rate-setting findings with respect to O&A in Order 59/18 pages 141 to 142, which can be summarized as follows:

> "The **Board accepts the O&A forecast for the Test Year** for financial forecasting and **rate-setting purposes**…The **Board accepts that the level of detail needed for a full testing of the forecast is not available until the results of the Voluntary Departure Program are known**…The Board acknowledges Manitoba Hydro's efforts to implement cost containment measures…The **Utility's review of its operations, at a time of restructuring and transition, presents an opportunity to find further areas to reduce O&A costs**. The **Board recommends that Manitoba Hydro continue these efforts, both in terms of staff reductions and Supply Chain Management, after the Voluntary Departure transition concludes.**" (Emphasis added)

The PUB made the following recommendation to MH with respect to O&A in Order 59/18 on page 264, as follows:

> "**4. Make efforts** to find **further areas to reduce O&A costs**, both in terms of **staff reductions** and **Supply Chain Management**, **after** the **Voluntary Departure Program transition concludes**." (Emphasis added)

The only information on the record of the current regulatory proceeding to support the O&A target setting for 2019/20, is contained in the response to Coalition/MH I-13 b and c which requested an updated version of MH Exhibit #78

from the last GRA. The following schedule provides an updated O&A target calculation that was requested in that information response:

Figure 14 - MH Electric O&A Targets					
	2018/19			2019/20	
	$ Million's	% Change		$ Million's	% Change
	1	2		3	4
Actual O&A 2017/18/Projected O&A 2018/19	**516.9**			**501.2**	
Projected labor cost increases	9.0	1.74%		9.2	1.84%
Projected non-labor cost increases	3.0	0.58%		3.0	0.60%
Total cost increases	**12.0**	**2.32%**		**12.2**	**2.43%**
Projected Bipole III Operating Costs	8.4			4.5	
Projected labor savings through staff reductions	-33.5			-0.8	
Projected sourcing savings through supply chain project	-2.7			-4.3	
Total cost savings	**-36.2**			**-5.1**	
Change in Capitalization assumptions	-7.2			5.9	
Provision for Restructuring Costs	7.3			-7.3	
Rounding				-0.2	
Projected Electric 2018/19 & 2019/20 -MH	**501.2**	**-3.04%**		**511.2**	**2.00%**
Source					
Column 1 & 3 - response to Coalition/MH 14 b c					

The key observations from Figure 14 and the response to Coalition/MH I-13 b and c with respect to the O&A targets are as follows:

1. The cumulative impact of labor savings through staffing reductions to 2018/19 has been revised downward from $65.5 million in Exhibit #78 to $53.4 million in the information request, a reduction of $12.1 million or 18.5%.
2. The cumulative labor savings to 2019/20 are now forecast at $54.3 million;
3. Total escalation on labor and non-labor costs is now forecast at $12.0 million (2.32% overall escalation) for 2018/19 and $12.2 million (2.43% overall escalation) for 2019/20 for a cumulative total of $24.2 million;

4. The provision for restructuring costs was reduced from $12.0 million to $7.3 million for 2018/19 in the information request;
5. The full year impacts of the forecast operating costs for Bipole III is approximately $12.9 million in 2019/20; and
6. Changes to capitalization assumptions decrease the O&A target by $7.2 million in 2018/19 and increase the 2019/20 O&A target by $5.9 million. There is no evidence provided by MH as to the reasons and calculations of these adjustments to capitalization assumptions.

In the response to Coalition/MH I-15 d, MH indicates that the 2018/19 O&A budget now includes $7.3 million to support transitional business requirements and that the $7.3 million was not allocated to specific Operating/Corporate groups and held as contingency. MH also confirms that it is not including any unallocated contingency funds for transitional requirements in the 2019/20 budget.

In the response to Coalition/MH I-15 e, MH also confirmed that:

> "There **were no actual expenditures associated with the unallocated funding for transitional business requirements** compared to a budget of $3.4 million to the end of September 2018 and a budget of $5.4 million **to the end of December of 2018**." (Emphasis added)

In the response to Coalition/MH I-13 g, MH has provided explanations for the updates to the labor savings from the VDP and sourcing savings from the Supply Chain Initiative which can be summarized as follows:

- The $70 million of O&A labor savings from the VDP estimated at the last GRA were based on an assumption of 70% savings flowing to O&A and 30% flowing to capital while the current estimate of cumulative labor savings to 2019/20 of approximately $54 million are now based on an assumption of 60% savings flowing to O&A and 40% flowing to capital based on current experience; and

- The $45 million of cumulative O&A sourcing savings from the Supply Chain Initiative estimated at the last GRA has now been reduced to $14 million of cumulative savings in the 2019/20 O&A target. MH indicates that this significant reduction is a result of that fact that a portion of the savings were efficiency savings that cannot be quantified and that the corporation has chosen not to renew the engagement of the supply chain consultant and as a result the savings are expected to be realized over a longer period of time.

In accordance with the information provided by MH in these information requests, the cumulative expected labor and sourcing savings to 2019/20 related to O&A have been reduced from a projection at the last GRA of $115 million to a more current estimate of $68 million, a reduction of $47 million or approximately 41%.

In addition, the rate-setting observations in Section 4.4 of Appendix A, outline additional concerns with respect to the calculation of labor savings and cost escalation.

It is important to note that the cumulative escalation of $24 million for 2018/19 and 2019/20 is offsetting about 35% of the combined staffing and sourcing savings of $68 million, in the space of two fiscal years.

At a rate of escalation of 2% or higher from 2018/19 onward, which equates to annual escalation in excess of $12 million, these projected O&A savings will be offset by escalation in approximately 6 years ($68/$12). This high-level calculation is confirmed by the fact that Electric O&A in MH Exhibit #93 was $536 million in 2016/17 (last year before the VDP) and is projected to return to $536 million by 2022/23 in MH Exhibit #93, just three fiscal years after the 2019/20 test year. This is projected to occur despite the implications of the Province of Manitoba's public sector wage freeze legislation (Public Services Sustainability Act) and cost saving measures in the Manitoba public sector in general.

It is recommended that the PUB reemphasize its O&A rate-setting findings from Order 59/18 that MH continue to actively manage its O&A costs and by including

a provision for O&A productivity for rate-setting in 2019/20. In the circumstances of reducing savings forecasts, public sector wage freeze legislation and the PUB findings from Order 59/18 that MH must continue to find additional savings in O&A, it is not consistent for MH to return to a default assumption of 2% escalation for O&A for rate-setting purposes. To do otherwise will subject consumers to ever increasing O&A costs and will not assist MH and the PUB to manage the financial and rate pressures in an era of major capital projects.

Taken as a whole, the analysis would suggest that for rate-setting purposes and in the absence of a detailed 2019/20 O&A budget to support the O&A targets, that the PUB utilize a 1% O&A escalation assumption to factor in its findings with respect to the need to reduce controllable O&A costs in an era of major capital projects in Order 59/18. The 1% O&A escalation assumption was utilized by MH between MH13 and MH15.

With a 1% O&A escalation assumption, total escalation for 2018/19 and 2019/20 would be approximately $10 million, which would represent about 15% of the cumulative savings of $68 million to 2019/20. In addition, using 1% O&A escalation, Electric O&A would grow to about $504 million in 2022/23, a difference of $32 million from the trajectory in MH Exhibit #93 (which represents about a 1.9% rate reduction based on current Electric revenues at existing rates of $1.7 billion).

It is also noted in the responses to PUB/MH I-24 a and Coalition/MH I-12 b, that there was an $8.1 million increase in collection costs in 2017/18 from the $4.3 million actual collection costs in 2016/17, for a total amount of $12.4 million (Appendix 8, page 2) as a result of an assessment of collectability of arrears. It appears that this is a one-time occurrence as the annual forecast for uncollectible accounts in the updated response to PUB/MH I-15 reverts back to an amount of $4.3 million for 2018/19. As MH's O&A targets use the ending 2017/18 O&A amount as the opening amount for the calculation of the 2018/19 target, this one-time expense should be normalized out of the calculation for rate-setting purposes.

Based on the record of this proceeding and considering the foregoing analysis, it would be reasonable for the PUB to make the following adjustments to MH's O&A target calculations for rate-setting purposes:

1. Make a normalization adjustment to the opening amount of O&A for the 2018/19 fiscal year in the O&A target calculations to remove the one-time and non-recurring increase in collection costs of approximately $8.1 million in 2017/18;
2. Adjust the 2018/19 O&A target to remove the $7.1 million provision for unallocated transitional contingency funds as none have been incurred for the first nine-months of 2018/19 and MH is not budgeting for these costs in 2019/20; and
3. Adjust the escalation assumptions in the 2018/19 and 2019/20 O&A target calculations to 1% to reflect an assumption of productivity for all of the reasons that were noted above. This would reduce escalation from approximately $12 million in each fiscal year to $5 million, with a cumulative adjustment of approximately $14 million to 2019/20.

The resulting O&A forecasts for 2018/19 and 2019/20 for rate-setting purposes would be approximately $479 million for 2018/19 and $489 million for 2019/20, for overall reductions of approximately $22 million, respectively. These amounts are supported in the following schedule:

Figure 15 - Electric O&A Target Setting Analysis - Adjusted for Rate-Setting					
	2018/19			2019/20	
	$ Million's	% Change		$ Million's	% Change
	1	2		3	4
Actual Electric O&A 2017/18	**516.9**				
Adjustment for one-time increase in collection expense	-8.1				
Adjusted Base Electric O&A 2017/18 & 2019/20	**508.8**			**478.9**	
Provision for 1% escalation	5.1	1.00%		4.8	1.00%
Projected Bipole III Operating Costs	8.4			4.5	
Projected labor savings through staff reductions	-33.5			-0.8	
Projected sourcing savings through supply chain project	-2.7			-4.3	
	-36.2			**-5.1**	
Change in Capitalization assumptions	-7.2			5.9	
Projected O&A 2018/19 - Adjusted for Rate-Setting	**478.9**	**-7.35%**		**489.0**	**2.11%**
Projected Electric 2018/19 & 2019/20 - MH	501.2			511.2	
Rate-Setting Adjustment	**-22.3**			**-22.2**	

9.0 A 3.5% Rate Increase is Not Required to Reduce the Risk of a Financial Loss in 2019/20

MH's key message in support of the updated application is that the proposed 3.5% rate increase **continues** to allow MH to plan for a modest level of net income in the event of low water flow conditions or the occurrence of other negative financial events and reduces the likelihood of future rate shock to ratepayers that could result from a financial loss in 2019/20.

This section will analyze this MH reason for application (reducing the likelihood of future rate shock from a financial loss in 2019/20) from the following perspectives:

1. What were the PUB findings in Order 59/18 with respect to how risks should be dealt with for rate-setting purposes and how retained earnings and regulatory action should be utilized;
2. What is the appropriate level of rate increase in 2019/20 to deal with the inherent financial risks that MH faces, and at the same time, adhere to the PUB findings in Order 59/18 with respect to how risks will be dealt with for rate-setting purposes; and
3. How can risk analysis be better used in future MH GRA's to assist the PUB in its rate determinations.

9.1. The PUB Set Out Important Guidance on How Key Risks of MH Should be Considered for Rate-Setting Purposes in Order 59/18

The PUB made a number of findings with respect to how MH's risks should be considered for rate-setting purposes in Order 59/18, pages 63 to 66, which can be summarized as follows:

> "…as the Board has demonstrated in past decisions – including in years of drought where the Board awarded rates in excess of those sought by the Utility – it will consider all of the facts and circumstances which confront Manitoba Hydro at that point in time in determining the appropriate rate relief…The **Board is prepared to take regulatory action** – whether through a rate rider, an interim rate increase, or a general rate increase –

as required in times when emergent situations face Manitoba Hydro…The **Board agrees** with the evidence of Morrison Park Advisors **that Retained Earnings should be used to manage drought risk in combination with regulatory action by the Board**. The **Board further agrees** that **interest rate** and **export price risks over the long term** should **be addressed with rate increases as and when those risks materialize**. **Rates should not be set to increase Retained Earnings to manage those longer-term risks**…the **Board is prepared to consider regulatory action when required to address emerging risks facing Manitoba Hydro**…the Board finds that the 7.9% requested and projected rate plan is not the appropriate balanced plan for meeting the risks and challenges that confront the utility…However, the **Board concludes that there is merit to gaining a better understanding of the financial reserves required for Manitoba Hydro under various circumstances**. This would include **consideration of risk tolerances**, **what risks should be protected by reserves** and the **circumstances which would guide the need for more aggressive rate increases** to continue full cost recovery for Manitoba Hydro…Consideration of the appropriate level of financial reserves for example a minimum retained earnings test, is best done through a collaborative approach with stakeholders…The **Board directs** Manitoba Hydro to participate in **a technical conference**…for the **consideration of the establishment** of a minimum retained earnings test or similar **test to provide guidance in the setting of consumer rates for use in rule-based regulation**. The test or rule is to be based on **maintaining appropriate** or minimum **levels of retained earnings** and **meeting other financial metrics** in the **face of potential risks to the Utility**." (Emphasis added)

The PUB directed (Directive #9) on Page 267 of Order 59/18, that a technical conference be held to consider the establishment of a minimum retained earnings or similar test to provide guidance in the setting of consumer rates for use in rule-based regulation. Subsequently, on its own initiative the PUB set

aside Directive 9 based on concerns that the technical conference had become an adversarial process with greater cost and complexity than had been contemplated at the time of the directive and that the potential delay in the filing of MH's next GRA until the technical conference was concluded, would be contrary to its aim of assisting MH in achieving a regular regulatory cycle (Order 128/18).

9.2. A 1.0% to 2.0% Rate Increase Would be More Than Sufficient to Minimize the Risk of a Financial Loss in 2019/20 while Adhering to the PUB Findings in Order 59/18 Related to How Risk Should Be Adressed to Rate-Setting

In Figure 2.10 of the original application, MH provided a table of key variable sensitivity impacts on the net income (loss) from 2019/20 Interim Budget, with and without the 3.5% proposed rate increase. MH presented sensitivities for (1) low (10th percentile) and high (90th) water flow conditions, (2) colder and warmer than normal winter weather, (3) +/- 1% interest rates and (4) low and high export prices.

At the time of the original rate application, MH was projecting a $28 million loss without the proposed rate increase and as such the downside risk scenarios (low water flow, warmer winter weather, +1% interest rates, low export prices) produced a possible range of losses from $43 million (+ 1% interest rates) to $229 million (low water 10th percentile). The downside risk scenarios produced a possible range of net income (losses) of between a $16 million profit (+ 1% interest rates) to a $169 million loss (low water 10th percentile) with the 3.5% rate increase. MH concluded that the likelihood of a financial loss in 2019/20 is greater without the proposed rate increase under the range of sensitivities considered.

Given the significant improvement in the financial outlook ($92 million) as a result of the update of the application and the fact that MH provided information on less extreme water flow conditions (the 20th and 80th percentiles) in the updated application, the Consumers Coalition requested MH to update Figure 2.10 in information request Coalition/MH I-8 b as well as include the less extreme water

flow sensitivities and provide all of the risk sensitivities assuming four rate increase scenarios for 2019/20 of 0%, 1%, 2% and 3.5%.

In the response to Coalition/MH I-8 b, MH indicated the following:

> "The **table below excludes the +/- 1% interest rate sensitivity** as the November 30, 2018 filing assumed all debt issues in 2018/19 and 2019/20 were impacted by a change in the forecasted interest rates…**Since actual debt issuances have been locked-in to December 31, 2018, the financial impacts to the 2019/20 Approved Budget are reduced** since there is a smaller volume of new debt issuances exposed to fluctuations in interest rates." (Emphasis added)

MH indicated in the response to Coalition/MH I-8 d, that it does not assign probabilities for the colder/warmer than normal winter weather, +/- 1% interest rate and low/high export price sensitivities.

Since MH is most concerned about the impacts of risks that could result in a financial loss in 2019/20, the following schedule (Figure 16) summarizes the updated Figure 2.10 for only the downside risk sensitivities that present significant financial risk to MH. Figure 16 provides the following nine combinations of risk sensitivities for each of the four rate increase scenarios for 2019/20 of 0%, 1%, 2% and 3.5%, but excludes any rate-setting adjustments:

1. Approved 2019/20 Budget;
2. Warmer than normal winter weather;
3. Low export price case;
4. 50% of warmer winter weather and lower export price;
5. 100% of warmer winter weather and lower export price;
6. Low water flow – 20th percentile (less extreme water flow case);
7. 50% of warmer winter weather, lower export price and 20th percentile water flow;
8. 100% of warmer winter weather, lower export price and 20th percentile water flow; and

9. Low water flow – 10th percentile (extreme water flow case).

Figure 16 includes the combination risk sensitivities (#4, 5, 7 and 8) to provide a rough indication of downside risk scenarios that result from the occurrence of more than one of the key risks.

Figure 16 - Rate Increase Scenarios & Downside Risk Sensitivities - without Rate-Setting Adjustments - 2019/20 Net Income

Sensitivity #	No Rate Increase 1	1% Rate Increase 2	2% Rate Increase 3	3.5% Rate Increase 4
1. Approved 2019/20 Budget (expected)	**64**	**78**	**93**	**115**
2. Warmer than normal winter weather (-$49 million)	15	30	44	66
3. Low Export Price Case (-$25 million)	39	54	68	91
4. 50% Combination 2 & 3 (-$37 million)	27	41	56	78
5. 100% Combination 2 & 3 (-$74 milion)	**-10**	4	19	41
6. Low Water Flow - 20th Percentile (-$74 million)	**-10**	4	19	41
7. 50% Combination 2, 3 & 6 (-$74 million)	**-10**	4	19	41
8. 100% Combination 2, 3, & 6 (-$148 million)	**-84**	**-70**	**-55**	**-33**
9. Low Water Flow - 10th Percentile (-$138 million)	**-75**	**-60**	**-45**	**-23**

Sources:
Response to Coalition/MH 8 b

The key observations from Figure 16 with respect to rate-setting for 2019/20 are as follows:

1. The individual warmer winter weather, low export price and 20th percentile water flow sensitivities (#2, 3 & 6) all are expected to produce a positive net income under all rate scenarios, with the exception of the no rate increase scenario for the 20th percentile water flow sensitivity which produces an expected net loss of $10 million;

2. The combined warmer winter weather, low export price and 20th percentile water flow sensitivities (#4, 5, 7 & 8) are expected to produce a positive net income for the majority of the rate scenarios;
3. The no rate increase scenario is expected to produce expected losses of $10 million for the second and third combined scenarios (#5 & 7) and an expected loss of $84 million for the fourth combined scenario (# 8 - 100% of the impact of warmer winter weather, low export prices and 20th percentile water flows);
4. The 1% and 2% rate increase scenarios are expected to result in positive net income for all of the combined sensitivities, with the exception of the fourth combined scenario (# 8 - 100% of the impact of warmer winter weather, low export prices and 20th percentile water flows) which results in expected losses in the range of $55 million to $70 million;
5. The 2% rate increase scenario is expected to result in positive net income for the majority of the sensitivities (with the exception of #8 & 9) which ranges between $19 million and $68 million); and
6. All of the rate scenarios result in an expected loss (that ranges between $23 million and $75 million) for the extreme water flow sensitivity (10th percentile water flow).

Figure 16 above does not include the proposed rate-setting adjustments of $22 million that are discussed in Section 8.4. Figure 17 below includes the $22 million of proposed rate-setting adjustments for 2019/20:

Figure 17 - Rate Increase Scenarios & Downside Risk Sensitivities - with $22 million Rate-Setting Adjustments - 2019/20 Net Income					
		No Rate Increase	1% Rate Increase	2% Rate Increase	3.5% Rate Increase
Sensitivity #		1	2	3	4
1. Approved 2019/20 Budget (+ $22 million)		**86**	**100**	**115**	**137**
2. Warmer than normal winter weather (-$49 million)		37	52	66	88
3. Low Export Price Case (-$25 million)		61	76	90	113
4. 50% Combination 2 & 3 (-$37 million)		49	63	78	100
5. 100% Combination 2 & 3 (-$74 million)		12	26	41	63
6. Low Water Flow - 20th Percentile (-$74 million)		12	26	41	63
7. 50% Combination 2, 3 & 6 (-$74 million)		12	26	41	63
8. 100% Combination 2, 3, & 6 (-$148 million)		**-62**	**-48**	**-33**	**-11**
9. Low Water Flow - 10th Percentile (-$138 million)		**-53**	**-38**	**-23**	**-1**
Source:					
Response to Coalition/MH 8 b adjusted for rate-setting adjustments of $22 million					

The key observations from Figure 17 with respect to rate-setting for 2019/20 are as follows:

1. The individual warmer winter weather, low export price and 20th percentile water flow sensitivities (#2, 3 & 6) all are expected to produce a positive net income under all rate scenarios, including the no rate increase scenario;
2. The combined warmer winter weather, low export price and 20th percentile water flow sensitivities are expected to produce a positive net income for the majority of the rate scenarios (#4, 5 & 7), including the no rate increase scenario;
3. All of the rate scenarios result in an expected loss (that ranges between $11 million and $62 million) for the fourth combined scenario (# 8 - 100%

of the impact of warmer winter weather, low export prices and 20th percentile water flows);

4. All of the rate scenarios result in an expected loss (that ranges between $1 million and $53 million) for the extreme water flow sensitivity (#9 - 10th percentile water flow); and
5. The 1% and 2% rate increase scenarios are expected to result in positive net income for all of the combined sensitivities, with the exception of the fourth combined scenario (# 8 - 100% of the impact of warmer winter weather, low export prices and 20th percentile water flows); and
6. The 1% rate increase scenario is expected to result in positive net income for the majority of the sensitivities (with the exception of #8 & 9) which ranges between $26 million and $76 million).

The general observation from assessing both Figure 16 and Figure 17 is that the 1.0% rate increase scenario performs well when considering the $22 million proposed rate-setting adjustments (Figure 17) and that the 2.0% rate increase scenario performs well when the proposed rate-setting adjustments are not considered (Figure 16).

The PUB findings that are set out in Section 7.1 provide important guidance on how MH's risks should be considered for rate-setting purposes:

1. Key risks such as interest rate risk and export price risk should be built into rates when these risks materialize and not through building up of retained earnings;
2. Drought risk should be managed through a combination of retained earnings and regulatory action when required to address emerging risks facing Manitoba Hydro;
3. The PUB is prepared to take regulatory action (rate increases) when emergent risks such as drought are actually facing MH, but will not set rate increases to increase retained earnings to meet every risk faced by MH in advance of the occurrence of those risks; and

4. There is merit to gaining a better understanding of the level of reserves required by MH under various risk scenarios in order to provide guidance for setting rates.

In assessing the rate scenario and risk sensitivity analysis in Figure 16, it can be concluded that a 1.0% to 2.0% rate increase in 2019/20 would perform well against the PUB guidance in Order 59/18 for the following reasons:

1. This range of rate increases are expected to more than cover the individual non-water flow risks faced by MH in 2019/20 and is expected to result in a net income that exceeds the financial objective of MH in the original application (modest net income of $31 million);
2. This range of rate increase is expected to result in positive net income for the non-water flow combined risk scenarios, recognizing the fact that the combined probability that each one of these individually low probability events occurs in combination is expected to be quite low;
3. The PUB has found that drought risk should be managed from retained earnings and regulatory action (rate increase) when emergent drought conditions occur. MH is projecting that its Electric retained earnings will be $2.9 billion at the end of 2018/19 and the PUB has signaled that it is prepared to provide rate relief if drought conditions occur;
4. Notwithstanding the PUB findings noted in point #3, this range of rate increase also performs reasonably well in the event of some combination of the occurrence of non-water flow risks and a less extreme water flow condition sensitivity, once again recognizing the combined probability is expected to be quite low; and
5. Significantly higher rate increases than the proposed rate increase would be required to protect MH against an extreme water flow event and the combined occurrence of other non-water flow risks. The PUB has found that the imposition of significantly higher rate increases to protect against the combination all of the risks that could be faced by MH is not in the

public interest and not an appropriate balancing of the financial integrity of MH with the impacts of rate increases to customers.

The PUB finding that there is merit to gaining a better understanding of the level of reserves required by MH under various risk scenarios in order to provide guidance for setting rates, is discussed in Section 9.3.

9.3. MH's Uncertainty Analysis Could Be Enhanced for the Next GRA to Provide a Quantitative Tool to Further Guide the Incorporation of Risk Considerations into Rate-Setting

In reviewing how risk considerations can be an important tool in a rate-setting environment, it is useful to start by considering how enterprise risk management frameworks are applied to manage risks. The MH risk management process contains a number of steps (other than the Mission/Mandate and Reporting/Monitoring steps):

1. **Risk Identification**: Risks are identified based on the factors that influence the performance of the area of the Corporation being assessed;
2. **Potential Impact**: Risks are analyzed for potential impact and measured in terms of consequence and probability.
3. **Risk Treatment**: Actions are taken to reduce the probability of a negative event occurring or to reduce the negative consequences should a negative event occur; and
4. **Residual Risk**: Certain levels of residual risk may remain even after actions have been taken to reduce their probability and consequences. An assessment is performed to confirm that the residual risk levels are within approved tolerances.

It is acknowledged that there are limitations of one-off risk sensitivities and analysis provided by MH in Figure 2.10 of the original application and the analysis provided in section 9.2 that make that analysis less than ideal to inform the rate-setting decisions of the PUB.

The one-off risk sensitivities are relatively basic financial calculations. With the exception of water flow conditions, there is no information provided with respect

to the probability of the risk occurring and limited information on the consequence, risk treatments and residual risk. There is also no organized means to quantitatively aggregate the probability, consequence and residual risks that are faced by MH on an overall basis.

MH has shown significant initiative in developing the first generation of what it refers to as the Uncertainty Analysis that was filed in the NFAT proceeding and the second generation of the Uncertainty Analysis that was provided in the 2016/17 Interim Rate Application and Tab 4 of the last GRA. The Uncertainty Analysis is significantly more robust that one-off risk sensitivities in that it can be used to generate a broad range of possible financial outcomes for a number of combined risk sensitivities.

Unfortunately, the expedited and more limited scope associated with the current one-year rate proceeding has limited the information that has been presented to the one-off risk sensitivities and the Uncertainty Analysis was not updated and presented as part of the 2019/20 rate application.

As was outlined by the Consumers Coalition and MIPUG in their closing submissions at the last GRA, there is great potential to further develop a third generation of the Uncertainty Analysis to assist in future rate-setting determinations. On a summary basis, recommended enhancements included applying probabilistic thresholds to determine the appropriate rate path and build in regulatory actions (rate response) into the tool and a technical conference on risk scenarios modelled on the Dynamic Capital Adequacy Test (DCAT) used in PUB's rate-setting process for Manitoba Public Insurance (MPI).

There are interesting parallels between the Uncertainty Analysis and DCAT analysis that is used to determine the target capital range for MPI's compulsory motor vehicle insurance (Basic). It is noted that the DCAT not only includes the most plausible adverse scenarios, with a specified probability level for the adverse scenario over a specified time horizon but also considers both routine management and regulatory actions.

Management actions would be consistent with the PUB findings from Order 59/18 that MH take steps to further reduce its controllable costs considering the pressure on the financial outlook and rates as a result of the era of major capital projects. It is recommended that the Uncertainty Analysis also be enhanced to consider management actions.

There are also interesting parallels between these tools and MH's risk management process:

1. Analyzing the probability and consequence of plausible adverse scenarios is consistent with the Risk Identification and Potential Impact steps of the risk management process;
2. Considering both routine management and regulatory actions is consistent with the Risk Treatment step of the risk management process; and
3. Understanding the residual risk after routine management and regulatory actions and analyzing if the residual risk is within risk tolerance or whether or not more aggressive regulatory action is required if the residual risk is outside of appropriate risk tolerances is consistent with the Residual Risk step of the risk management process.

It is unfortunate that the Technical Conference to determine a minimum retained earnings or similar test was withdrawn based on procedural concerns with respect to the adversarial nature, cost, complexity and the potential delay in the filing of MH's next GRA. Whether or not the Uncertainty Analysis can be further developed into a more rules-based approach to rate-setting or be used as a less judgemental/more quantitative approach to develop a range of target capital for MH is beyond the scope of this review. In either case, the further development of the Uncertainty Analysis would be beneficial from a rate-setting perspective and it is recommended that the PUB direct that MH make enhancements to this analysis for the next MH GRA.

With respect to process, there is a spectrum of options that can be considered, from the collaborative technical conference approach that has been used for the MPI DCAT analysis to a generic hearing focused on determining a regulatory

framework with respect to the capital requirements of MH. Periodic generic hearings are utilized in other RBROR jurisdictions to determine the capital requirements through approval of an allowed capital structure and allowed return on equity. The results of these generic hearings do not result in a rate-change, rather the regulatory decisions are subsequently applied to a number of actual rate-setting processes. While the cost, complexity and adversarial nature of these generic hearings may be somewhat daunting, they can improve the effectiveness and efficiency of the regulatory process over the long-run by reducing the amount of time and cost spent debating capital requirements at each specific rate application hearing.

10.0 An Evaluation of the Continuum of Rate-Setting Options for the PUB results in the Recommendation of a 1.5% Rate Increase in 2019/20

This section of the Evidence will:

1. Evaluate the range of rate-setting options that are available to the PUB considering its mandate to set electricity rates that are just and reasonable through balancing the financial integrity of MH with the impact to customers; and
2. Make a rate increase recommendation for the 2019/20 fiscal year, considering the analysis findings and conclusions from Sections 4.0 to 9.0 of the Evidence.

10.1. There is a Continuum of Rate-Setting Options Available to the PUB for 2019/20 Ranging for No Rate Increase to 3.5% as proposed by MH

Considering the updated financial projections for the 2019/20 fiscal year and the analysis that has been presented in the preceding sections of the evidence, there is continuum of rate-setting options for the PUB, which can be summarized as follows:

1. Award **no rate increase for 2019/20 on a final basis**, recognizing that the updated projections for 2019/20 (without the proposed rate increase) result in a $64 million net income and that the 3.5% proposed rate increase cannot be justified by any quantifiable financial objective (net income) or financial metric (financial ratios);
2. Award a **1.0% to 2.0% rate increase for 2019/20 on a final basis**, recognizing that this level of a rate increase would be more than sufficient to protect against the risk of a financial loss in 2019/20, consistent with the PUB findings in Order 59/18 with respect to how risk should be addressed in rate-setting; and
3. Award the **full rate increase requested of 3.5% for 2019/20 on an interim basis**, recognizing the concern over the future financial outlook and potential rate volatility associated with the in-service of the Keeyask

generating station but also recognizing that there is no reliable long-term forecast available to the PUB to award this rate increase on a final basis.

10.2. A 1.0% to 2.0% Rate Increase in 2019/20, would Balance the Financial Health of MH with Customer Interests and Avoid an Erosion of MH's Capital Structure in 2019/20

On page 4 of Order 59/18, the PUB outlined that in setting just and reasonable electricity rates and in determining the general public interest, it balances two concerns:

1. The interests of MH's ratepayers; and
2. The financial health of Manitoba Hydro.

As was outlined in Section 5.1 of the Evidence, the PUB has traditionally extensively relied on a long-term financial forecast to apply the MCOS approach to set rates, promote rate stability and predictability for customers and balance the financial integrity of MH with rate impacts on customers over the longer-term.

The absence of a reliable long-term forecast in this rate proceeding poses a significant issue for the PUB and Intervenors in terms of the appropriate rate-setting framework to apply to evaluate MH's proposed rate increase as well as the evidence that is necessary to apply the appropriate rate-setting framework.

There is an argument for no rate increase in 2019/20 considering the updated forecast that is expected to result in a $64 million net income, without the proposed rate increase. Approving no rate increase for 2019/20 based solely on the financial circumstances of 2019/20 and the projected net income of $64 million would tend to balance the rate increase toward current customers with limited to no consideration of the longer-term financial outlook of MH (MRBROR or vertical rate-setting approach).

There is no quantifiable financial objective (net income), financial metric (financial ratios) or downside risk sensitivity that justifies awarding MH a 3.5% final rate increase based solely on the consideration of the financial circumstances in 2019/20. The PUB also lacks the evidence (a reliable long-term forecast) to

balance the rate increase fully toward the future financial health of MH and award a 3.5% rate increase (MCOS or horizontal rate-setting approach).

If the PUB were to approve a 3.5% rate increase it should be awarded on an interim basis only, recognizing that the revised IFF in the next GRA would be required to grant final approval or adjust the 2019/20 rate increase, as necessary. The PUB has outlined in Order 59/18 and in a number of previous rate decisions, that it has serious concerns over interim rate applications and would not consider future interim rate increases unless there are unforeseen or emergency circumstances. There has been no claim of unforeseen or emergency circumstances by MH in the evidence of this proceeding.

There is a reasonably recent PUB precedent in Order 5/12 on the approach to take to approve rates when MH has not provided sufficient proof to support final approval of rate increases as sought by MH. On page 27 of Order 5/12, the PUB found the following:

> "As set out in this Order, the **Board is not satisfied that it has sufficient proof from MH**, upon consideration of all of the evidence, **to support a final approval of rate increases** as **sought by MH**. In this GRA proceeding, **MH has failed to substantiate the reasonableness of its capital plans** and the **expected revenues to support such a capital plan**. As such, **the Board cannot, and will not, endorse MH's rate increase requests as applied for**. However, the **Board has determined** that **MH must receive inflationary increases** for the test years **to avoid erosion of its capital structure** in the **test years**." (Emphasis added)

In the rate decision in Order 5/12, the PUB dealt with a scope limitation in terms of lack of evidence related to MH's future capital expansion plans and balanced the financial health of MH with customer interests and awarded inflationary rate increases to avoid erosion of MH's capital structure in the test years.

While the fact pattern may not be the exactly the same in the current circumstances, the principle underlying the rate decision in Order 5/12 is the

same. In the absence of the appropriate evidence (updated/reliable long-term IFF in the current rate proceeding) to award a 3.5% rate increase on a final basis based solely on concerns over the future financial outlook of MH, the PUB could award a 1.0% to 2.0% rate increase in 2019/20, that would balance the financial health of MH with the customer interests and avoid an erosion of MH's capital structure in 2019/20.

A 1.0% to 2.0% rate increase in 2019/20 would balance the financial health of MH with customer interests as this range of rate increases:

1. Is expected to generate net income of between $100 million and $115 million for MH in 2019/20, if MH is able to manage its O&A costs within a rate-setting target of $489 million for 2019/20;
2. Is expected to result in financial ratios that are consistent with or exceed MH Exhibit #93 from the last GRA, given that the projected financial ratios without a 2019/20 rate increase are consistent with the projected ratios including the 3.57% indicative rate increases in MH Exhibit #93 (See Section 4.0);
3. Protects against the risks of a financial loss in 2019/20 (erosion of MH capital structure) consistent with the PUB's findings in Order 59/18 on how key risks should be considered for rate-setting purposes;
4. Recognizes that MH has not adequately responded to the PUB findings from Order 59/18 to reduce controllable costs (BOC, DSM, O&A) in an era of major capital projects and adjusts for $22 million of reasonable rate-setting adjustments related to O&A;
5. Is still expected to generate a reasonably healthy net income of between $78 million and $93 million for MH in 2019/20, even in the event that MH is unable to manage its O&A costs within a rate-setting target of $489 million for 2019/20; and
6. Recognizes that there are a number of qualitative rate-setting considerations that have been identified in this Evidence (see list below) that have not been quantitatively factored into the above noted expected

financial outcomes but should be considered by the PUB for the purpose of setting rates in 2019/20.

As outlined in point #6, there are a number of qualitative rate-setting observations that should be considered by the PUB for the purpose of setting 2019/20 rates:

1. Potential sales of additional surplus capacity in 2019/20 (See Appendix A, Section 4.3);
2. Potential for lower BOC spending in 2018/19 and 2019/20 as a result of a track record of past underspending (See Section 8.1 and Section 4.5 of Appendix A);
3. Potential to lower DSM spending based on a review of the cost effectiveness of programs in accordance with the PUB rate-setting findings in Order 59/18 (See Section 8.2 and Section 4.1 of Appendix A); and
4. Potential for lower interest rates than forecast due to emerging concerns over tepid economic growth (See also Section 4.6 of Appendix A).

10.3. It is Recommended that the PUB Approve a 1.5% Rate Increase for MH in 2019/20

The key conclusions from Sections 9.2 and 10.2 are that a 1.0% to 2.0% rate increase in 2019/20:

1. Is more than sufficient to minimize the risk of a financial loss in 2019/20 while adhering to the PUB findings in Order 59/18 related to how risk should be built into rate-setting for MH;
2. Would balance the financial health of MH with customer Interests and avoid an erosion of MH's capital structure in 2019/20; and
3. The 1.0% lower end of this range performs well when considering the $22 million proposed rate-setting adjustments and the 2.0% higher end of this range performs well when the proposed rate-setting adjustments are not considered.

Considering that there is no rules-based or formulaic rate-setting framework that can be used to exactly specify a precise rate recommendation for MH, the 1.5% midpoint of this range is recommended for 2019/20.

11.0 Overview of Manitoba Hydro's Cost of Service and Rate Design Proposals

As part of its original application dated November 30, 2018, Manitoba Hydro is requesting approval of a 3.5% rate increase to be applied equally, across all customer classes including the new First Nations On-Reserve Class, except for Diesel General Service. For Diesel General Service customers, MH is proposing to increase the grid portion of the rates (the Basic Charge and first 2000 kWh per month) for non-government customers. The basis of MH's request for an across-the-board rate increase, but for the exception noted appears to include:

1. The consideration of a one-year electric rate application;
2. The absence of a Prospective Cost of Service Study ("PCOSS");
3. The anticipated significant impact on customer class costs associated with Bipole III coming into service; and
4. The on-going leave to appeal regarding the creation of the First Nations On-Reserve Class that remains before the Court of Appeal.

While the updated application in which MH continues to propose a 3.5% rate increase is silent with respect to the application to cost of service and rates, it is assumed that Manitoba Hydro continues to request approval of the rate increase on an across-the-board basis. In the absence of a Formal Letter of Application that outlines the specific approvals being sought, through the course of the information request process, Manitoba Hydro also informed that it is seeking to apply the rate increase to the Basic Charge associated with the General Service Government and First Nation Education Class[2] but exclude that Class' Energy Charge from the rate increase.

This section of the evidence will analyze the reasons for MH's proposal to apply the requested rate increase on an across-the-board basis from the following perspectives:

1. The role of cost of service in the rate-setting process;

2 Coalition/MH 35 (a-b), page 2

2. PUB direction in Order 59/18 to differentiate rates to more closely align costs with revenues by class with consideration given to the number of classes outside the Zone of Reasonableness ("ZOR") and Order 68/18 Revenue to Cost Ratio ("RCC") results;
3. The absence of a Prospective Cost of Service Study and the absence of a Diesel Cost of Service/Revenue Study;
4. The profound changes from PCOSS18 associated with the addition of Bipole III; and
5. The movement of RCCs into the ZOR anticipated with the addition of Bipole III.

11.1. The Key Conclusions that Support an Across-the-Board Rate Change, should any Rate Increase be granted for 2019/20

A summary of the key conclusions of the evidence in the sections that follow includes:

1. A cost of service study is a basic and necessary tool used for purposes of ratemaking. With the much stricter application of cost of service to revenue as directed in Orders 164/16 and 59/18, the role of COS is explicit in affecting rate changes by class. Thus, a COS Study must be prepared with each GRA to support the PUB's final rate determination.
2. The absence of a cost of service study presents an issue for the PUB and intervenors. The PUB requires a strong evidentiary foundation on which to justify a differential rate increase, and in its absence, it is necessary that any rate increase granted be applied on an across-the-board basis.
3. Differentiated rate changes flowing from Order 68/18 resulted in a tightening of the range of revenue to cost coverage and improvement in class RCCs, as intended by Order 59/18. However, the impacts associated with the Net Export Revenue ("NER") methodology change and the rate freeze for the FNOR and Diesel Residential Classes more than offset the improvements achieved through the differentiated rate change and, overall, contributed to less alignment of revenue with cost responsibility and a wider ZOR.

4. Generally, changes in cost associated with Finance Expense and Depreciation as well as Export Revenue (particularly given the current COS treatment which allocates export revenues on the basis of each class' allocation of generation and transmission costs) tend to have the greatest impact on the results of MH's Cost of Service Study overall. Other cost changes (both in magnitude and nature of the cost) or load changes can have sizable impacts on the results of a cost of service study. However, the addition of Bipole III, given the magnitude of the investment and its nature, that is, a generation-related investment with no incremental revenue offset (such as export revenues), will profoundly impact cost of service. There is not any other cost change forecast in the current application that will undo the anticipated cost of service impacts of Bipole III.

   The only information in this proceeding is contained in the response to PUB/MH 61 (a) in which MH incorporates the revenue requirement associated with Bipole III (based on revised capital costs of $4.77 billion) in PCOSS18 to provide indicative Revenue-to-Cost ratios by class. The addition of Bipole III will result in most class RCCs to be within the ZOR and thus, it is reasonable that any rate increase granted be applied on an across-the-board basis.

5. Recognizing there is no cost of service basis to support the creation of the First Nations On-Reserve Class and the limited scope of the current proceeding that excludes bill affordability matters, there is no evidence to date to exclude the First Nations On-Reserve Class from a rate increase. It is recommended that any rate increase be applied on an across-the-board basis, including the FNOR Class.

   MH's requested rate increase is inclusive of the revenue shortfall associated with the FNOR (and Diesel Residential) rate freeze implemented June 1, 2018. It is recommended this shortfall continue to be funded by all customer classes implicitly, through net income.

6. In the absence of a Diesel Cost of Service/Revenue Study to support MH's proposed exemption for Diesel non-grid rates, and given the only evidence on the record to date quantifies the RCC of the Diesel Class overall to be in the order of magnitude of 80%, it is recommended that any rate increase flowing from this Application be applied on an across-the-board basis, including all rate components of the Diesel Classes.
7. Recognizing the persistent above the zone of reasonableness RCCs of the GSS ND Class, even with the addition of Bipole III, a lower than average rate increase should be considered, should a rate increase be granted.

11.2. Through Orders 164/16 and 59/18, the Role of the Cost of Service Study which determines how an Overall Approved Rate Increase is Assigned to the Customer Classes, is Explicit in the Setting of Rates. This means a Cost of Service Study must be prepared with each GRA to support Rates

The determination of a utility's rates may be viewed in three phases. The first phase focuses on the determination of the overall revenue requirement or the overall rate level of the utility as discussed in the preceding sections. In this first phase consideration is given to the reasonableness of the forecast of customer energy, peak load, the utility's operating and capital costs. The focus is on whether the overall utility costs and forecasts are reasonable, necessary and prudently incurred in the provision of utility service.

In the second phase, the utility's established revenue requirement is allocated to each of its customer classes through the preparation of a Cost of Service Study ("COSS" or "Cost Allocation"). Cost of service studies analyze which customer or group of customers cause the utility to incur the costs to provide service. It is important to note that cost of service studies do not look to allocate only the incremental rate increase sought by a utility (in the case of the current proceeding, Manitoba Hydro's requested 3.5% rate increase), but rather, analyze a utility's full revenue requirement and associated capital investments. A COSS

may also be used in the determination of the third phase of ratemaking, the design of rates of the various customer classes.

While Cost of Service is often described as a basic and necessary tool to be used for purposes of ratemaking, it is also considered the fundamental standard for assessing the just and reasonability of rates by utilities, regulators and stakeholders.

Manitoba Hydro's cost of service study is based on embedded costs of a single test year which are based on a forecast of costs based on the book value of the utility's assets, in other words, its established revenue requirement or overall cost to serve. The concept of cost causation is central to the determination of a sound cost of service study – or those who cause the costs should pay for the costs. While other ratemaking objectives can and do influence a cost of service methodology, in Order 164/16, the PUB concluded that the principle of cost causation is paramount and that other principles and goals of ratemaking including fairness and equity considerations (other than cost to serve), rate stability and efficiency should be considered in the overall process of setting rates but not as part of cost of service methodology.

The result of a cost of service study determines each class' share of the utility's overall revenue requirement which is compared to the revenues collected from each class to derive a RCC. A customer class with revenues equal to their allocated costs would result in an RCC of one or unity. Because a cost of service study cannot identify for sure the cost of providing service to a class, a Zone of Reasonableness is generally accepted. A ZOR is necessary given the existence of significant joint and common costs of a utility which are used by all or nearly all customers and need to be allocated accordingly. For, Manitoba Hydro, this also occurs because of the dominance of hydraulic investment with significant fixed costs and because of the magnitude of export revenue. In Order 59/18, the PUB concluded that a ZOR of 95% to 105% was reasonable for Manitoba Hydro thus, customer classes with RCCs in that range are deemed to represent full cost recovery.

It should also be noted that Cost Allocation is a “zero-sum game”. This means that to the extent that costs are shifted away from one customer class resulting in lower rates for that class, those costs are picked up by other customer classes resulting in higher rates for those classes such that the utility’s established revenue requirement is intact. In the current proceeding, this means that if it is determined that certain customers (or customer classes) are exempt from any rate increase granted by the PUB, the loss of revenue that would otherwise occur must be recovered by another class or classes.

During the past two or more decades across-the-board rate increases were applied for and granted almost exclusively. Implicitly, this can be considered as excepting a ZOR broader than a range of 95% to 105%. In this framework, matters such as a final revenue requirement, a cost of service study reflecting final RCCs, or the creation of a FNOR Class flowing from a GRA would be of little practical significance in terms of the establishment of rates for the test year. However, given the much stricter application of cost of service to revenue as directed in Orders 164/16 and 59/18, these matters can affect rate changes by class explicitly. In this new paradigm of potential differentiated rates and a tight Zone of Reasonableness, the role of COS is explicit. It also means that a COS Study must be prepared with each GRA to support the PUB’s final rate determination.

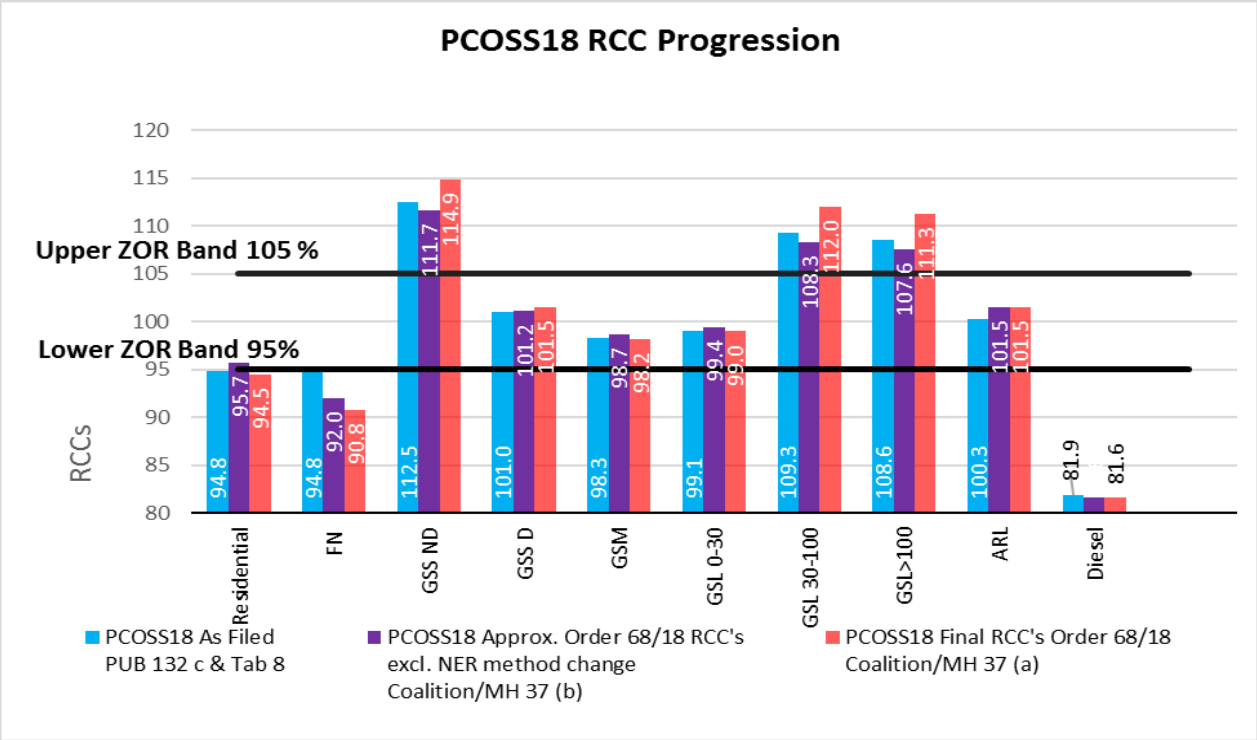
11.3. In Order 59/18, the PUB directed that rates be differentiated by class based on PCOSS18 to more closely align revenues by class with allocated costs and considering the number of classes outside the Zone of Reasonableness

The PUB made the following findings with respect to its direction to MH to differentiate rates in Order 59/18 pages 198-199:

> *“The **Board finds** that the Revenue to Cost Coverage ratio output of the Cost of Service Study is to be used at this time **to more closely align the revenues collected from each customer class with the costs caused**….**While the cost of service should not necessarily be the overriding factor in designing rates,** it is consistent with the rate-making*

*principle of fairness…**The Board directs Manitoba Hydro to begin to implement differentiated rates**….General Service Small Non-Demand, General Service Large 30-100kV, and General Service > 100kV are **all** overpaying costs to a significant degree outside of the zone of reasonableness….For the 2018/19 Test Year rates, Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness. **The rate increase impact** of doing so **is to be shared across all customer classes that are either below or within the zone of reasonableness**: Residential, General Service Small Demand, General Service Medium, General Service Large 0-30 kV, and Area & Roadway lighting. As a result, **the Residential customer class, which is currently the only class below the zone of reasonableness, will begin to move into the zone of reasonableness…This approach will also assist in limiting the prospect of over-correction** of the issue **at the time Bipole III enters service…The Board will…consider adjustment to the differentiation of rates as necessary, including to consider the impact of Bipole III.** "* (Emphasis added)

The following table provides the results of PCOSS18 revenue to cost coverages flowing from Order 68/18 as prepared by MH in response to Coalition/MH 37 (a). This analysis appears to include the June 1, 2018 differentiated rate increases, the implementation of the rate freeze to the First Nations On-Reserve Class and Diesel Residential, as well as the alternate Revenue to Cost Coverage Ratio methodology directed in Order 59/18 to apply net export revenues as an offset to cost. These final PCOSS18 RCCs flowing from Order 68/18 have been compared to MH's PCOSS18 (as filed) as well as the PCOSS18 RCCs which largely isolate the results associated with the differentiation of rates:



The key observations from the above table with respect to RCCs are as follows:

1. Movement toward the ZOR and a tightening of the range of revenue to cost coverage was achieved through the differentiation of rates directed in Order 59/18 as indicated by the purple bar, but for the FNOR and Diesel Classes. The Residential Class, for example, moved from slightly outside the ZOR (94.8%), into the ZOR (95.7%).
2. Order 68/18 resulted in an overall decline of the Residential Class' RCC from 94.8% to 94.5% despite an above average differentiated rate increase on June 1, 2018 of 4.04% (vs. 3.6%), once all changes including the application of net export revenue as an offset of cost (rather than additional revenue) are reflected.
3. The GSL>100kV Class' RCC increased from 108.6% to 111.3% primarily attributable to the change in methodology associated with net export revenue and the implementation of the First Nations On-

Reserve Class, partially offset by a lower than average differentiated rate increase.

4. PCOSS18 (as filed) resulted in RCCs in the range of 82% to 112.5%. The final PCOSS18 RCCs flowing from Order 68/18 resulted in an RCC range of 82% to 114.9%.
5. As Manitoba Hydro notes in response to Coalition/MH 37 (a), given the limited cost data available for the First Nations On-Reserve Class, their corresponding RCC is likely overstated – meaning their RCC is likely less than 90.8% and conversely, is likely understated for the Residential Class – meaning their RCC is likely greater than 94.5%. This results from the large electric space heating load associated with the First Nations On-Reserve Class[3].

The conclusion from this analysis is that the differentiated rate changes directed by the PUB in Order 59/18 resulted in a tightening of the range of revenue to cost coverage and improvement in class RCCs. However, the impacts associated with the Net Export Revenue methodology change and the rate freeze for the FNOR and Diesel Residential Classes more than offset the improvements achieved through the differentiated rate change and, overall, contributed to less alignment of revenue with cost responsibility and a wider Zone of Reasonableness ("ZOR").

As MH observes, the Residential Class RCC is likely understated but lacks costing detail to support its conclusion. While the matter of RCCs, differentiated rates, and the ZOR were discussed at the last MH GRA, it is anticipated these matters will be the subject of further review at MH's next GRA in light of the limited scope in this regulatory proceeding as well as PUB direction in Order 59/18. The initial comments are 1) Recognizing that there is no cost of service basis to support the creation of the First Nations On-Reserve Class, the spirit of the FNOR Class is not to isolate the cost to serve based on the traditional cost characteristics associated with this class' energy, demand and customer

3 PUB/MH 61 (a)

numbers but rather a policy decision of the PUB to begin addressing matters of bill affordability; and 2) There are some interesting issues for COS that arise with the addition of significant generation-related capital investments that are suggestive that the current ZOR is quite tight. It is anticipated these matters will be raised for further review at the next full GRA.

11.4. No COS has been prepared for the purposes of the 2019/20 Rate Application which is required to Differentiate Rates

One of Manitoba Hydro's key messages in its Application is that in the absence of a cost of service study to support its 2019/20 Rate Application [4] that its requested rate increase be applied to all customer classes on an across-the-board basis (with some exceptions discussed below). Manitoba Hydro states that:

> *"In consideration of this one-year electric rate application and in the absence of an updated PCOSS, Manitoba Hydro is proposing to apply the increase to all components of the rates (monthly basic charges, energy charges and demand charges) on an across-the board basis for all customer classes, with the exceptions of Diesel General Service. For Diesel General Service customers Manitoba Hydro is proposing to increase the grid portion of the rate (Basic Charge and first 2000 kWh per month for non-government customers) by 3.5% with the non-grid portion of the rate remaining unchanged"*[5]

A one-year electric application appears to be the basis by which MH has justified the lack of a PCOSS20, an across-the-board rate request, and the application of the rate increase to all components of the rates. It is noted however, that cost of service studies are always prepared on the basis of a single test year – in other words a COS Study is done on a "snapshot basis". When asked to explain the rationale for having not prepared PCOSS20 MH responded[6]:

4 Also confirmed in response to Coalition/MH 40.
5 MH 2019/20 GRA, page 34, lines 10-12, page 35 lines 1-8.
6 Coalition/MH 40

> *"Manitoba Hydro has provided an updated version of PCOSS18 that incorporated the revenue requirement increases from Bipole III* ***in the response to PUB/MH 61 (a),*** *which demonstrates the impact on class revenue cost coverage ratios. In addition to updates to the revenue requirement, this update also includes the implementation of Directives 24, 25 and 27 from Order 59/18." (Emphasis added)*

It is curious as to why a COSS has not been prepared for the 2019/20 Test Year, particularly recognizing the largest asset in Manitoba Hydro's history was brought on-line, namely Bipole III – to which Manitoba Hydro acknowledges in its evidence, will have a significant impact on customer class costs. It is unfortunate that only upon the request of the PUB through the information request process, did Manitoba Hydro provide some sensitivity analysis.

The absence of a cost of service study presents an issue for the PUB and intervenors given that cost of service is a basic and necessary tool to be used for purposes of ratemaking. The PUB requires a strong evidentiary foundation on which to justify a differential rate increase, and in its absence, any rate increase granted should be applied on an across-the-board basis.

The following sections provide additional factors suggesting that applying any rate increase on an across-the-board basis is both necessary and reasonable.

11.5. Bipole III coming in service in 2018/19 is a profound change in circumstances from PCOSS18

As discussed above, a cost of service study is a one-year snapshot that reflects only the established revenue requirement of the test year, in the case of the current proceeding, the 2019/20 fiscal year. Any differences between test years that result in changes in a utility's outlook, or actuals, do not explicitly form part of COS.

For purposes of illustration, the following schedule provides a comparison of the revenue requirement underpinning PCOSS18[7] and by which the resultant RCCs

7 MH 2017/18 GRA, Tab 8, pages 16-17

flowing from Order 68/18 provided in Section 9.4 above reflects, with the revenue requirement associated with Manitoba Hydro's current Application, that would have been the basis of its 2019/20 Cost of Service Study:

	IFF16 2017/18 Test Year $ (Millions)	2019/20 Test Year $(Millions)	DIFF
	PCOSS18	Update	$
GCR at Approved Rates	1,569	1699	130
Additional GCR	88	50	(38)
Bipole III Reserve Account	(119)	78	
Exports	454	418	(36)
Other	30	27	(3)
Total Revenue	**2,022**	**2,272**	**250**
Less Additional GCR (net of Bipole Reserve)	81	50	(31)
Less Other Revenue	30	27	(3)
Total Revenue included in PCOSS	**1,910**	**2,195**	285
O&M	518	511	(7)
Net Finance Expense	558	741	183
Dep & Amortization	396	505	109
Water Rentals and Assessments	124	117	(7)
Fuel and Power Purchased	135	127	(8)
Capital and Other Taxes	132	148	16
Other Expenses	115	74	(41)
Corporate Allocation	8	8	
Net Movement in Regulatory Deferral	(68)	(70)	(2)
Net Income	102	110	8
Total Cost of Service/Revenue Requirement	**2,022**	**2,271**	**249**
Less Additional CGR (net of Bipole III Reserve)	81	50	(31)
Less Other Revenue	30	27	(3)
Total Revenue Requirement incl. in PCOSS	**1,910**	**2,194**	**284**

The purpose of the above table is to illustrate the changes in costs that underpin PCOSS18 and those that would have formed part of a 2019/20 cost of service study. Generally, the costs as highlighted in yellow above tend to be most impactful to a cost of service study, not only because of the magnitude of the cost change itself, but importantly for cost of service purposes, the nature of the cost (for example, generation vs. transmission vs. distribution or export revenue).

The key observations from the above schedule are as follows:

1. The most significant impact on the cost of service study relates to the increase in Net Finance Expense and Depreciation and Amortization Expense. These increases are virtually all related to the carrying costs associated with Bipole III, which for purposes of COS is a generation-related asset and will have profound effects on class RCCs.

   From a cost of service perspective, while the overall changes in revenue requirement components as shown in the above table can be impactful to RCC, what is perhaps more important, is the nature of the cost or revenue change – in other words whether costs are generation, transmission or distribution-related or export revenue. In the case of Bipole III, it is both - the magnitude of its cost relative to current net investment as well as the fact that it is a generation-related asset for purposes of the cost of service without any incremental revenue offset (such as export revenue), will result in a profound effect on customer class cost responsibility which is unlikely to be offset by any other impact to RCCs flowing from the next cost of service study. As MH acknowledges in response to PUB/MH 1-61a (page 3):

   "Updating the PCOSS to incorporate the Bipole III revenue requirement increases the generation-related portion of revenue requirement from 55% to 63%. This asymmetrical increase in cost by function will have a large impact on classes that use relatively more, or less, Generation than average. For example 88% of the costs of serving the General Service Large > 100kV are Generation related, compared to only 18% of the costs of serving Area and Roadway Lighting. As a result the addition of Bipole III significantly decreases the revenue cost coverage ratio of the GSL class, while significantly increasing that of Area and Roadway Lighting. There

are less pronounced RCC impacts for classes such as General Service Medium that have functional cost proportions closer to system average"

2. **It is not anticipated that a decline of $36 million in Export Revenue will materially affect RCCs.**

   Given that Export Revenue is 20% of the revenues relative to domestic customer class revenue (and at times much larger), large changes in export revenues can be greatly impactful on a cost of service study and RCCs. This is particularly the case given the current COS treatment flowing from Order 164/16 which allocates export revenue on the basis of each class' allocation of generation and transmission costs. Those customer classes with relatively more (or less) generation and transmission cost allocation than average can experience more pronounced impacts on their RCCs with large changes in export revenue – for example GSL customer classes compared with the Residential Class for whom distribution costs are a significant share of their allocated costs.

   However, an increase in the export revenue forecast of $60 million as part of the 2017/18 GRA, were shown to impact RCCs by +/- less than 1%.[8] While it is recognized the comparison between that analysis and the current proceeding are not exact, it is not anticipated that a decline of $36 million in export revenues will materially affect RCCs.

3. **While PCOSS18 lacks a detailed O&M budget needed for a proper functionalization of costs, and as discussed elsewhere, likely overstated in the current forecast, the impact on the results of the cost of service study will not undo the impact of Bipole III.**

8 PUB/MH 90 (2017/18 GRA)

Most O&M expenses are related to a particular type of plant facility and therefore follow the cost allocation method of the corresponding plant. However, as MH acknowledges,[9] the functionalization of its O&M is significantly outdated, based on forecasts available in early 2016. PCOSS18 is thus impacted by a lack of accounting detail in the absence of a detailed O&M budget– which is needed for a proper functionalization of costs.

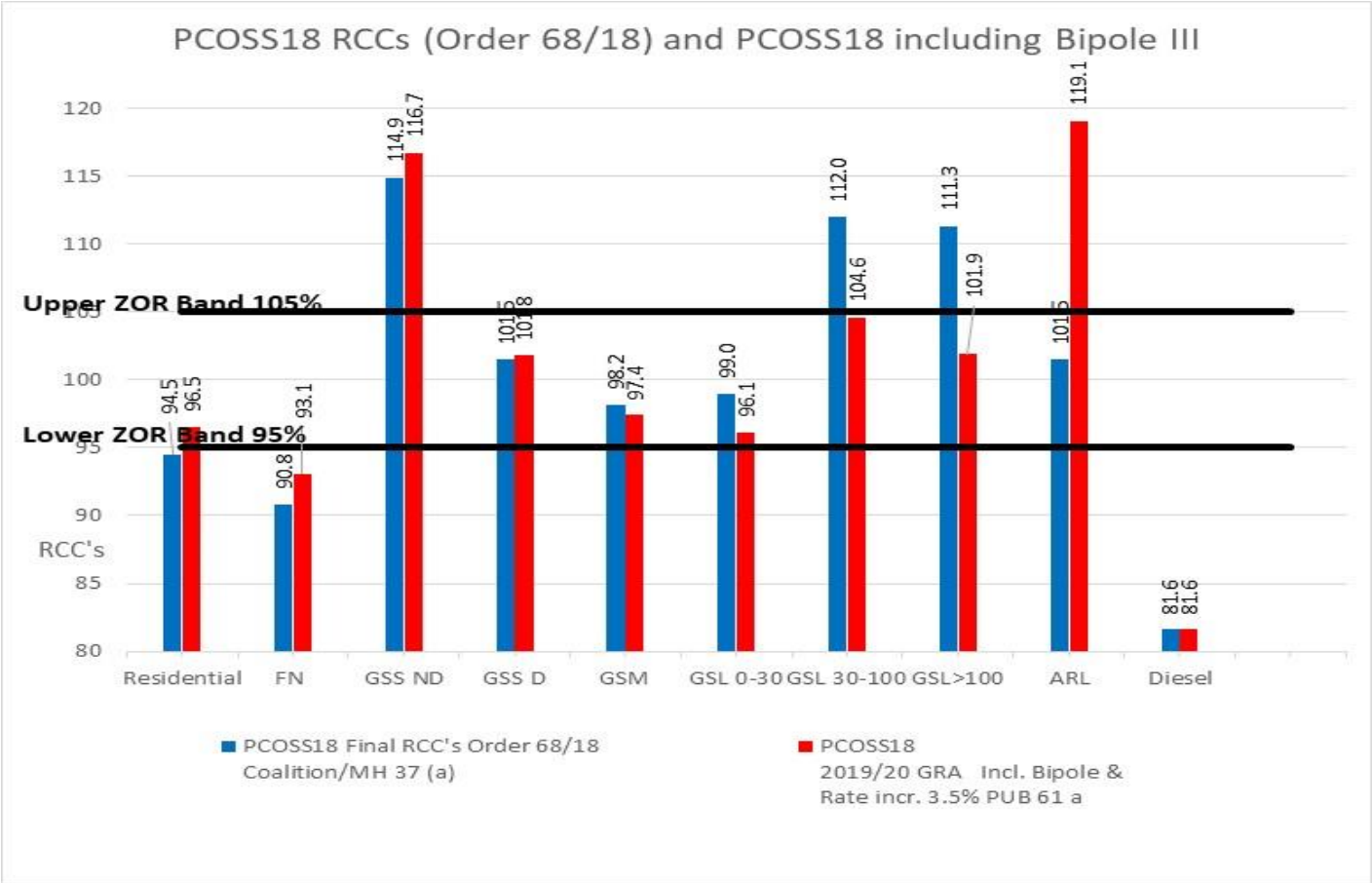
As shown in the above table, O&M represents approximately 25% or more of MH's total revenue requirement. Compared with PCOSS18, O&M would have declined by $7 million. This overall O&M cost change would have minimal impacts on cost of service results. However, the same degree of certainty cannot be placed on the impacts to RCCs as a result of significant corporate restructuring – it is simply not known at this time. Generally, however, O&M costs do not have the same profound impact on class RCCs like the addition of large investment in generation and transmission or export revenue. And, with the addition of Bipole III-related operating costs, the potential to unwind the effects on RCC related to Bipole III is exceedingly small.

There are other cost changes or significant load changes that can have an impact on the results of a cost of service study other that those discussed above. However, the addition of Bipole III, given the size of the investment that is generation-related and with no incremental revenue offset, will profoundly impact cost of service that no other cost change forecast in the current application will unwind.

9 Coalition/MH 39

11.6. The only information in this Proceeding indicates that the in-service of Bipole III is expected to move the Residential & GSL Classes into the Zone of Reasonableness

The only information in this proceeding is contained in the response to PUB/MH 61 (a) in which MH prepared a version of PCOSS18 that incorporates the revenue requirement associated with Bipole III (based on revised capital costs of $4.77 billion) to provide indicative Revenue-to-Cost ratios by class. As shown in the table below, the resulting RCCs indicate that the majority of classes are within the Zone of Reasonableness:



The data observations from the above table are as follows:

1. The GSL > 100kV Class RCC declined from 111.3% to 101.9%, **a more than 9% increase in allocated cost** responsibility compared to their revenues.
2. The Residential Class RCC moved from 94.5% to 96.5%, or **a 2% reduction in allocated cost** responsibility compared to their revenues.
3. The Area and Roadway Lighting Class RCC moved from 101.5% to 119.1%, or an **almost 19% cost responsibility reduction** compared with their revenues.
4. The majority of the other classes are within the ZOR.
5. Given that the data for Diesel was not available, an RRC-placeholder of 81.6% was assigned. However, it is expected that there will be some effect on Diesel rates imputed at grid rates.

The key observations from the above table are as follows:

1. Given the size of the Residential Class and for whom distribution-related costs are a significant share of their allocated costs, it is not surprising that their RCCs are more rigid in that it takes a fair amount of cost movement to impact their RCCs.
2. The GSL Classes are sensitive to generation-related cost (and revenue) which can be seen in their RCC movement.
3. Bipole III is anticipated to move the Residential and GSL Classes within the Zone of Reasonableness.

11.7. The only Classes outside the Zone of Reasonableness include First Nations On-Reserve, Diesel, ARL and GSS ND. Given the persistent RCCs above the ZOR, it is recommended that a rate increase lower than average be considered for GSS ND

As discussed in Section 9.3, Cost Allocation is a “zero-sum game”. This means that to the extent costs are shifted away from one customer class resulting in lower rates for that class, there will be an impact on all other customer classes as those costs must be recovered to allow the utility the opportunity to recover its full revenue requirement.

Given the potential impact on the Residential Class, the following observations and recommendations are being made with respect to customer class RCCs that are anticipated to be outside the ZOR.

ARL

It is recommended that any rate increase granted to MH flowing from this Application be applied on an across-the-board basis for the ARL Class on the basis that there has been a sizable imperceptible benefit distorting its RCC because of the cost of service methodology related to DSM discussed below.

The cost of DSM, which was previously allocated to each class based on class participation (the class that benefits from the program spending is charged with the costs of the program) is now being treated as a system resource as directed in Order 164/16 on the basis that it avoids future generation cost and thus functionalized 100% to generation. This is a reasonable methodology change, one of the many judgments inherent in cost of service methodology. However, the impact of this COS methodology change is likely to benefit the ARL Class to a large degree.

MH experienced a similar extreme case of this kind of benefit provided to the ARL Class during the mid-1990s. At that time, most of MH's DSM investment was in the HPS lighting program. The ARL class was obtaining the majority of the benefits but would have paid a minuscule portion of the cost as part of the then allocation methodology of allocating DSM costs on the basis of generation, transmission and distribution ("G,T,D"). While MH initially maintained the G,T,D allocation for all other programming, it became apparent that similar concerns arose for at least some of it. Eventually MH elected to allocate DSM costs based on participation because it seemed fairer and because those who benefited from the DSM programs could be reasonably identified.

Over the past several years, MH has made a large investment in the conversion of streetlighting to LED and a similar cost of service case has materialized.

Given that DSM is not necessarily aligned with each class' share of generation resources and given that a single class can benefit both by reduced usage (and lower allocated costs) as well as avoiding the cost of a DSM program aimed specifically at the class, in this case LED conversion, a significant benefit will accrue to the ARL Class. The impact to RCC will be both imperceptible as well as distorting. There may be a further RCC impact as the LED program did not meet the RIM of 1.0 as an individual program.

It is understood that even in the absence of the DSM issue discussed above, the addition of a large generation asset such as Bipole III will drive the RCC of the ARL class up, all else equal, given their disproportionately low (in terms of ARL's overall cost to serve) allocated cost of generation. On this basis, it would be reasonable to apply any rate increase granted to MH as part of this Application on an across-the-board basis including the ARL Class until the impacts of the cost allocation methodology can be assessed vis a vie the LED Streetlighting DSM program. It is advisable that MH prepare such analysis in conjunction with its next cost of service study at which point any potential biases in the cost of service study can be considered as part of the establishment of revenue-to-cost ratios and ultimately rates.

GSS ND

The RCCs pertaining to the GSS ND since 2009 are provided in the following table:

	PCOSS10	PCOSS11	PCOSS13	PCOSS14	PCOSS14	PCOSS14	PCOSS18	PCOSS18	PCOSS18 Order 59/18	PCOSS18	PCOSS18 2019/20 GRA	PCOSS18 2019/20 GRA
	Nov 2009		Meth Changes July 2012	Amended Dec 2015	Amended Dec 2015 Bipole III	Order 164/14	As Filed	Update*	Incl. Directives 5,27,24,25	Incl 7.9% & Bipole III	Incl. Bipole & June 1, 2018 Rates	Incl. Bipole & 3.5% incr.
	COS Review PUB I-15	17/18 GRA Tab 8 App 8.1	COS Review PUB I-15	COS Review PUB I-15	COS Review PUB I-55	PUB 132 c (2017/18 GRA) & Tab 8	PUB 132 c (17/18 GRA) & Tab 8	PUB II - 90 (17/18 GRA)	PUB 61 a	PUB II-88 (17/18 GRA)	PUB 61 a	PUB 61 a
GSS ND	105.7	104.8	107.6	108	110.4	108.5	112.5	112.1	115.5	115.3	116.7	116.7

Given this class' RCC appears to be persistently outside the ZOR despite the range of methodologies and cost changes over this period of time as well as the addition of Bipole III, it may be appropriate to consider a lower than average rate increase for this class.

<u>The First Nations On-Reserve and Diesel Classes</u>

As part of the 2019/20 Rate Application, Manitoba Hydro is requesting approval of a 3.5% rate increase to be applied on an across-the-board basis including the First Nations On-Reserve Class established through Order 59/18 and some Diesel rates. Manitoba Hydro has applied to exempt the Diesel General Service Energy Charge for consumption exceeding 2000 kWh and the Diesel Government and First Nation Education Energy Charge as well. In the absence of a formal letter of application that is normally provided in a typical GRA filing that outlines the specific approvals the utility is requesting, MH's rate change request required clarification as provided through the response to Coalition/MH 39 (a-b).

In response to Coalition/MH 35 (a-b), MH cited the Settlement Agreement as its rationale for exempting certain Diesel rates from the rate increase being sought in this application:

> *"Under the terms of the Settlement Agreement, rates in the Diesel communities are designed to recover operating costs only. Diesel rate changes are primarily driven by changes in the price of diesel fuel, which represents over half the cost to serve the Diesel communities.*
>
> *Factors such as water flow conditions, interest rates, depreciation rates or major assets going in service, which impact the need for rate increases from grid customers, do not affect the cost to serve Diesel communities. Therefore, Manitoba Hydro has not requested an increase to the Government and First Nation Education rate in this Application.*

Rates for all Residential consumption, General Service usage up to 2000 kWh per month, are priced at ***equivalent to grid rates on a policy basis.*** *Manitoba Hydro has proposed applying the 3.5% increase to these rates,* ***which remain well below the actual cost to serve these customers****"*

Manitoba Hydro confirmed in response to Coalition/MH 36 (a-d) that the Diesel Class contributes approximately $1.6 million annually less toward their cost of operations. It should be noted that the Diesel Cost of Service/Revenue Study is the basis by which MH establishes the non-grid portion of Diesel Rates – just as the PCOSS is used in the determination of grid rates. The Settlement Agreement is only one of many data sources used in the preparation of the Diesel Cost of Service/Revenue Study and is not in evidence to support the rate exemption being sought.

Diesel Cost to Serve in past years was dealt with via a separate proceeding, the last of which was in approximately 2010. Given that is nearly a decade ago, it is recommended that the matter of Diesel Rates be dealt with on a timelier basis. With Diesel Rates imputed at grid levels, in part, it would seem sensible for MH to consolidate the adjustment of Diesel Rates (non-grid) with its general rate applications to ensure a more timely review and to allow for the impact to other customers classes to be understood.

Given that the thrust of MH's Application is to avoid the potential erosion of its financial position, it is questionable why it would forego the revenue loss associated with Diesel. In the absence of a Diesel Cost of Service/Revenue Study to support MH's proposed exemption for Diesel non-grid rates, and given the only evidence on the record to date quantifies the RCC of the Diesel Class overall to be in the order of magnitude of 80%, it is recommended that any rate increase flowing from this Application be applied on an across-the-board basis, including all rate components of the Diesel Classes.

Recognizing that there is no cost of service basis to support the creation of the First Nations On-Reserve Class and the limited scope of the current proceeding that excludes bill affordability matters, there is no evidence to date to exclude the First Nations On-Reserve Class from a rate increase. It is thus recommended that any rate increase be applied on an across-the-board basis, including the FNOR Class. This would allow for the current rate subsidy to be maintained, and the opportunity for matters currently before the Court of Appeal to conclude.

There is an interesting dichotomy in the perspectives advanced by MH. In response to Coalition/MH 35 (a-b) as quoted above, Manitoba Hydro acknowledges that the Diesel Rates are well below their cost to serve (of approximately $1.6 million)[10] – a significant subsidy recoverable from all other classes[11], and which MH states has been implemented on a policy basis. As part of MH's Compliance Filing dated May 15, 2018, MH determined that approximately $1.7 million of revenue otherwise foregone was to be explicitly recovered on an equal basis from all other classes[12] as part of the determination of June 1, 2018 rates. It begs the question of the inconsistency between MH's opposition to the First Nations On-Reserve Class directed by the PUB in Order 59/18 as one measure to address matters of bill affordability (public/social policy) while not opposing the same treatment afforded to Diesel customers since at least 2010, a policy decision it has acknowledged in response to Coalition/MH 35.

On a final note, it is assumed that MH's overall rate increase request is inclusive of the revenue shortfall associated with the FNOR, which will implicitly be funded eventually through all customer class rates. The recovery of these costs/foregone revenue from all customers is appropriate as it is consistent with the spirit of Order 68/18, as well as with the long established policy associated Diesel Classes.

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10 Coalition/MH 36 (a)
11 Coalition/MH 36 (d)
12 Coalition/MH 37 (a-c)

The conclusions from this section are:

1. The only COSS-related information in this proceeding is contained in the response to PUB/MH 61 (a) in which MH incorporates the revenue requirement associated with Bipole III (based on revised capital costs of $4.77 billion) in PCOSS18 to provide indicative Revenue-to-Cost ratios by class. The addition of Bipole III will result in most class RCCs to be within the ZOR and thus, it is reasonable that any rate increase granted be applied on an across-the-board basis including the FNOR Class and all Diesel rates. MH's requested rate increase is inclusive of the revenue shortfall associated with the FNOR (and Diesel Residential) rate freeze implemented June 1, 2018, which is to continue to be funded by all customer classes, implicitly through net income. Recognizing the persistent RCCs of the GSS ND Class above the zone of reasonableness even with the addition of Bipole III, a lower than average rate increase should be considered, should a rate increase be granted.

2. While it is an issue for discussion at the next MH GRA, as can be seen by the profound effect that Bipole III will have on RCCs, the current approved range of reasonableness of +/- 5% is quite tight considering the movement in RCCs ranges from +/- 2% to 19% that results.

12.0 MH's Rate Design Proposal is Acceptable for the 2019/20 Rate Application but It Would Be Appropriate for MH and the PUB to Review Ratemaking Objectives and Rate Design at the Next GRA

As outlined on page 16 of Order 164/16, the PUB process for setting MH's electric rates involves a three-step sequential process:

1. Determination of PUB approved revenue requirement;
2. Determination of a PUB approved Cost of Service Study; and
3. Determination of a PUB approved rate design, including energy charges, demand charges and basic monthly charges and consideration of ratemaking principles.

MH's revenue requirement has been consistently reviewed on an annual or bi-annual basis, with the last major review occurring in 2017/18 & 2018/19 GRA and resulting in PUB Order 59/18. In contrast, MH's Cost of Service Study and rate design have been reviewed periodically. The last comprehensive review of the Cost of Service Study occurred at the 2016 Cost of Service Review proceeding with resulted in Order 164/16. It is unclear when the last major review of rate design was undertaken, particularly as it relates to the consideration of ratemaking principles.

In its 2019/20 Rate Application, MH is requesting that any approved rate increase be applied across all components of the rate structure (monthly basic charges, energy charges and demand charges) on an across-the-board basis for all customer classes, with some exceptions for Diesel (non-grid).

This section of the evidence will briefly review the appropriateness of MH's requested rate design for the 2019/20 Rate Application and provide considerations for the review of rate-making principles and rate design at the next GRA.

12.1. The PUB Did Not Approve Any Changes to MH's Rate Design in Order 59/18

The PUB made the following findings with respect to Rate Design in Order 59/18, pages 207 to 208:

> *"**The Board finds that there will be no change in the rate design**, except as may be required to achieve the class revenue targets as directed in the previous section…**First, the board does not accept that there should be a reduction in demand charges or elimination of the demand ratchet**…This **change in the existing rate structure would contribute to the magnitude of bill impact that some customers will have to absorb, including the general rate increase as well as the shift in revenue responsibility as a result of differential rates**…In addition, the Board heard evidence in this proceeding about the potential for increased use of disruptive technology for non-utility generation, such as customer solar photovoltaic installations. This could potentially require the review of demand charges in the near future in order to ensure that class revenues are fully recovered and that the value of grid reliability is properly assessed when used by customers as a back-up power resource…**Second, the Board finds that the implementation of residential inverted block rate is not supported on the evidence**. Due to the updated marginal value, which is less than the current residential energy rate, an inverted block rate would send an inappropriate price signal and would be contrary to the rate-making principle of efficiency. However, the Board notes that the General Service classes have a declining block rate structures…**Manitoba Hydro is directed to provide in its next GRA filing the rationale for the rate design for the General Service customer classes and an evaluation of the block thresholds and charges**…**Third, the Board finds that neither of Manitoba Hydro's illustrative residential rate design nor the electric space heating residential rate design proposed by Mr. Chernick are to be implemented.** These rate designs are not justified on a cost of service*

*basis, given the higher cost to serve electric space heating customers…**Finally**, with regard to time-of-use rates, the **Board continues to be of the view that time-of-use rates should be implemented for General Service Large customers**; however, due to the updated marginal values filed in this proceeding, further study is required. The **Board therefore…directs Manitoba Hydro to bring forward for the Board's review at the next GRA a time-of-use rate design proposal**…**Manitoba Hydro is directed to consult with General Service Large customers before filing its proposal with the Board**."* (Emphasis added)

The PUB made the following directives with respect to rate design in Order 50/18, pages 270 to 271:

"**28. Manitoba Hydro provide in its next GRA filing the rationale for the declining block rate design for the General Service customer classes and an evaluation of the block thresholds and charges**…**29. Manitoba Hydro file with the next GRA a time-of-use rate design proposal, including the results of the consultation undertaken with General Service Large customers prior to filling the proposal with the Board**" (Emphasis added)

In Order 126/18, the PUB directed that the timing of the public review process with respect to time-of-use rates will be determined by the PUB once more information is providing regarding the status of the rate design process, consultation and the anticipated timing for the filing of the next GRA. In Order 1/19, the PUB found that the development of a time-of-use rate design proposal was not in the scope of the current regulatory process.

12.2. MH Should Review Its Ratemaking Objectives and Rate Design for the Next GRA

In Order 164/16, page 27, the PUB found:

> *"**The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals** should not be considered at the COSS stage…The Board finds that Manitoba Hydro's ratemaking principles and goals of **rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be considered in a General Rate Application ("GRA")** and not in the cost of service methodology."*

As part of the 2017/18 GRA, Manitoba Hydro's primary or perhaps only ratemaking objective was the recovery of revenue requirement:

> *Manitoba Hydro noted its primary rate design objective, and how it related to one of Bonbright's "Criteria of a Sound Rate Structure". Manitoba Hydro views its primary ratemaking objective as stated on page 2 of Tab 9 of 22 this Application: "**Recovery of Revenue Requirement** – Rates must provide the Corporation the opportunity to fully recover its allowed revenue requirement….Similarly, Professor James Bonbright states that a sound rate structure should have: **Effectiveness in yielding total revenue requirement** under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety" (Page 30 of Manitoba Hydro's Book of Documents No. 2, Exhibit MH-116-2). **Both of these objectives reinforce the desirability of rates being designed to recover, to the fullest extent possible, the amount of revenue requirement identified** as being the responsibility of each individual customer class. Therefore, in the event that the PUB determines that revenues must be shifted between classes to achieve a change in RCC, that direction should be made prior to the calculation of rates for final approval. In that way, Manitoba Hydro will be able to design*

rates to accomplish the desired shift of RCCs while maintaining ***overall the ability to fully recover its allowed revenue requirement****"*

In the 2019/20 Rate Application, MH did not include any discussion of ratemaking principles or goals in advancing its rate design proposal that any approved rate increase be applied across all components of the rate structure on an across-the-board basis for all customer classes. MH simply indicated that this proposal was "in consideration of this one-year electric rate application and in absence of an updated PCOSS" (Original application, page 35).

When asked if the MHEB's comprehensive review is expected to establish new ratemaking objective priorities for the Corporation, MH indicated in the response to Coalition/MH I-41 that:

> *"****Manitoba Hydro continues to use the established rate design principles and guidelines as included in Attachment 1*** *when proposing rates whether at the outset of a General Rate Application or in compliance with and Order from the Public Utilities Board of Manitoba.* ***The priority given to the various principles is determined with consideration to the prevailing circumstances at the time of each rate application****. The MHEB's comprehensive Corporate Strategic Planning initiative is currently being developed/scoped and as such* ***we are unable to advise if new ratemaking objectives will be a deliverable of this process****"* (Emphasis added)

As a matter of ratemaking theory, the possible goals and objectives of rate-making include: meeting the utilities established revenue requirement, fairness and equity, economic efficiency, simplicity and understanding of the rate form, competitiveness of rates, stability, social goals, and administrative ease.

There is generally no hierarchy for these principles, other than perhaps the objective of meeting the annual revenue requirement, as the relevance and weight given to these principles vary with the circumstance and context of a utility

and regulatory application. Many of the goals of ratemaking are conflicting and informed judgement is required to obtain a compromise.

Cost allocation methodologies include both embedded and marginal value of service. Rate forms include declining block rates, inverted rates, flat rates (or a combination of them). These methodologies and rate forms or tools of rate design are useful in working toward one or more of the goals of rate making.

For example, the goal of economic efficiency may be achieved using a marginal cost analysis, or embedded cost of service that gives weight to cost behaviour and/or rate structures that reflect marginal or incremental cost. Fairness and equity is often viewed as giving significant weight to the cost to serve (allocated costs). Thus, the methodologies and rate forms may be viewed, not as right or wrong, but how they aid in obtaining the utility's ratemaking objectives.

While Manitoba Hydro provided a summary of ratemaking goals it states it continues to use in conjunction with a general rate application[13], it goes on to state that the relative priority of each goal will be based on the prevailing circumstances at that time. Unfortunately, other than the recovery of revenue requirement as provided in the 2017/18 GRA, it is unclear, what Manitoba Hydro's ratemaking objectives are or the weight ascribed to them.

With ratemaking, like all projects, it is important to begin with an end in mind. Given the considerable judgement involved, it's good to know what you are trying to achieve before you commit to methodology/rate form to get there.

By way of example, a comparison of electricity rates to neighbouring jurisdictions was filed as part of Manitoba Hydro's Application, as it has done for nearly two decades. In years past, the goal of lowest or among the lowest rates was explicitly recognized in the Corporation's strategic objectives. In current times, despite recognizing the competitiveness of rates as a ratemaking goal and filing the data, it is unclear what weight that MH ascribes to this objective, particularly when the same material was filed as part of the Corporation's 2017/18 GRA, in

13 Coalition/MH 41

which it was seeking a rate increase double the magnitude compared with this GRA.

Manitoba Hydro acknowledges that the relative emphasis it places on its ratemaking objectives can change over time. It would appear that with the MHEB review underway which is expected to provide the Corporation with overall rate-setting and other strategic direction, it is an optimal time to review the Corporation's ratemaking objectives and relative priority as well. Such guidance would be beneficial in the consideration of rate design matters to be reviewed flowing from Order 164/16 including for example, the Uniform Rate Adjustment and marginal costs, as well as rate increases associated with MH's large capital additions, and TOU, Solar PV, and the consideration of social goals flowing from Order 59/18.

It is advisable that Manitoba Hydro re-establish ratemaking objectives and their priority–to attain its broader goals and to obviate the need to simply arbitrarily adjust rates in a mechanistic manner which would render most rate design criteria mute. Through Orders 164/16 and 59/18, the PUB endorses that factors other than cost are appropriate in the establishment of rates. Depending on the priority ascribed to Manitoba Hydro's rate setting objectives, the result could well be rates that produce RCC ratios outside the ZOR.

12.3. MH's Rate Design Proposal is Acceptable for the Current 2019/20 Rate Application

From a review of Order 1/19, it appears that an overall review of MH's ratemaking principles and rate design is beyond the scope of this one-year rate application and that the scope would properly include a review of the MH specific proposal for an across-the-board application of any rate increase to all components of the rate structure.

As it relates to the 2019/20 Rate Application, MH's rate design proposal is acceptable within the circumstances of the current rate proceeding.

As noted above, effective ratemaking requires the three-step sequential approach of revenue requirement, cost of service and rate design, including consideration of ratemaking objectives. Revenue requirement and cost of service for MH has and continues to be reviewed and up to date in terms of MH's operational environment. Given there has not been a meaningful review of MH's rate design and ratemaking objectives it is recommended that the PUB direct MH to review its ratemaking principles for the next GRA, for the reasons noted in Section 12.2.

13.0 Robust Compliance and Directives Filings With Intervenor Participation Should Be an Integral Part of an Effective and Efficient Regulatory Process for the Current Proceeding and future GRAs

In analyzing the MH 2019/20 Rate Application it is apparent that there are process improvements with respect to compliance filings before the final approval of rate schedules flowing from a decision in this proceeding, that should be implemented for this regulatory process.

It is also noted that there are numerous PUB directives from Order 59/18 and prior PUB decisions that remain outstanding and that a full review of these outstanding directives is planned to occur at MH's next GRA (MH original rate application, page 1). With this in context in mind, it is critical that Intervenors should be involved in the directives process in advance of the next MH GRA, both to assist MH and the PUB in dealing with this backlog and avoiding future inefficiencies that can occur if Intervenors are not a part of the compliance process.

This section of the evidence reviews recommendations to improve the compliance filing and PUB directives process to improve the effectiveness and efficiency of future regulatory processes.

13.1. The PUB Directed a Compliance Filing and Consideration of a Process for Feedback and Clarification of All Outstanding and Ongoing Directives in Order 59/18

The PUB made the following findings with respect to the status and process for ongoing PUB Directives at pages 260 to 261 of Order 70/18:

> *"The **Board finds that the Utility has not complied with all or part of a number of past directives**. If Manitoba Hydro disputes a directive issued by the Board, the Utility may choose to file a request for variance or seek leave to appeal from the Manitoba Court of Appeal. The Board has jurisdiction to impose financial penalties and stay any future applications in the event that the Utility does not comply with all or part of a Board Order.*

The ***Board directs Manitoba Hydro to file with the Board on or before August 1, 2018 the status of compliance with all outstanding and ongoing directives****.* ***Manitoba Hydro is to provide with this filing the Utility's comments on a process for feedback and clarification of Board directives.****"* (Emphasis added)

The PUB made the following directives with respect to a compliance filing and the status and process for ongoing PUB Directives at pages 267 and 272 of Order 70/18:

*"****8. Manitoba Hydro recalculate and file, for Board approval, a schedule of rate reflecting the overall rate increase and differentiated rates effective June 1, 2018*** *for all customer classes,* ***together with all supporting schedules including proof of revenue, customer impacts, and revenue requirement by May 15, 2018****…****37. Manitoba Hydro file with the Board on or before August 1, 2018 the status of compliance with all outstanding and ongoing directives****, along with the* ***Utility's comments on a process for feedback and clarification on Board directives****."* (Emphasis added)

13.2. The PUB Should Direct a Full Compliance Filing With Intervenor Participation Before the Implementation of Any Rate Change Flowing from the Current Regulatory Proceeding

On page ix of MUPUG's closing submissions (MIPUG Exhibit #33) from the 2017/18 & 2018/19 GRA, it made the following recommendation:

"Similar to the recent Cost of Service hearing, ***Hydro should be directed to produce a compliance filing in response to the Board's Order, to generate an IFF scenario consistent with the Board's directions for confirmation by the Board that the directions were appropriately applied****.* ***Once confirmed, the procedures and approaches set out in this IFF*** *(e.g., approach to export price forecasting, depreciation, accounting for overheads)* ***should be considered the starting point for preparing future GRA forecasts.****" (Emphasis added)*

In response to PUB directive 8 from Order 59/18, for file its compliance filing, MH filed a 3-page letter, together with Rate Schedules and Proof of Revenue. Unfortunately, no supporting revenue requirement schedules reflecting the directives of the PUB, no cost allocation schedules, no details related to the creation of the FNOR Class or the ultimate RCC results by class were filed as part of the Compliance Filing.

As well, despite contributing significantly to the hearing process over a nine-month regulatory process, there was no participation of Intervenors in the review of the MH compliance filing flowing from Order 59/18 and the issuance of Order 68/18 that ultimately approved MH rates effective June 1, 2018.

The current process provides for significant insight to draw from in this regard. The above noted deficiencies in the MH compliance filing and the lack of participation of Intervenors in the process between Order 59/18 and Order 68/18 has meant that in the current proceeding much time and effort has been expended:

- Assessing and analyzing MH Exhibit 93 – the financial forecast that reflected many but not all of the PUB's direction flowing from Order 59/18 to understand the final outcome of the last regulatory process; and
- Seeking, assessing and analyzing cost allocation results, the creation of the FNOR Class, rate differentiation determinations and RCCs flowing from the last GRA.

During the past two or more decades across-the-board rate increases were applied for and granted almost exclusively. Implicitly, this can be considered as accepting a ZOR broader than a range of 95% to 105%. In this environment, matters such as a final revenue requirement, a cost of service study reflecting final RCCs, or the creation of a FNOR Class flowing from a GRA would be of little practical significant in terms of the establishment of rates for the test year. However, given the much stricter application of cost of service to revenue as directed in Orders 164/16 and 59/18, these matters can affect rate changes by

class explicitly. In this new paradigm, it is necessary that MH provide these schedules reflecting the direction of the PUB with support assumptions in its Compliance Filings to not only understand the assumptions made in the determination of rates, but importantly also to have an appropriate benchmark by which to measure future cost of service results and rates, in subsequent regulatory proceedings. With the PUB's direction to implement differentiated rates and a fairly tight ZOR, the role of COS is explicit. It also means that MH must prepare a COS Study with each GRA to support the PUB's final rate determination.

The effectiveness and efficiency of any future regulatory process is, in part, a function of an effective conclusion to the last rate process, for all parties, including Intervenors. For these reasons, it is recommended that the PUB should direct a fulsome compliance filing with intervenor participation before the implementation of any rate change flowing from the 2019/20 regulatory proceeding and future regulatory proceedings.

13.3. The PUB Should Consider the Consumers' Coalition Recommendations for Intervenor Participation In the Compliance and Directives Process for Implementation Before the Next GRA

In its letter of July 20, 2018, the PUB indicated that it was "initiating a post-hearing process consistent with the Board's commitment to a continuous improvement process" and that it welcomed "all parties in the GRA process to provide written comments, criticisms and constructive suggestions of a general or specific nature …"

In the spirit of continuous improvement, the Consumers Coalition provided a 14-page letter on August 17, 2018, outlining a number of comments on process considerations for a 2019/20 GRA. In this submission, the Consumers' Coalition provided a number of comments and observations on MH's response to Directive 37 from Order 59/18 and MH's proposed process for feedback and clarification of outstanding and ongoing PUB directives, that was filed with the PUB on August 1, 2018.

In particular, the Consumers' Coalition provided comments on MH's position that the intent of the proposed directives process is to improve the implementation, delivery and quality of responses to the PUB directives without adding "red tape" and "associated costs" as justification for exclusion of intervenors from its proposed process.

The Consumer's Coalition noted that MH's position on the exclusion of intervenors from the directives process did not address the fact that frequently intervenors and their experts are the very party that has recommended a particular directive in the first place and the PUB often builds Intervenor participation right into the directive. The Consumers' Coalition also noted its position that Intervenors have a significant role to play in:

1. Clarifying the scope of a PUB directive that they might have had a hand in recommending;
2. Suggesting alternative approaches and resources that are necessary to satisfying a directive;
3. Assisting the PUB and MH in determining the priority and timing of various directives with respect to future regulatory processes; and
4. Assisting in determining if the intent of a particular directive has been satisfied for rate-setting purposes.

The Consumers' Coalition went on to make a number of specific recommendations on MH's proposed directive process and an overall recommendation that the PUB develop guidelines for the compliance process including post-order compliance and directives review, compliance reporting at regular intervals and notice of compliance filing deadlines, the role and participation of Intervenors in the compliance/directives process, as well as funding for Intervenor participation.

It is recommended that the PUB consider the Consumers' Coalition comments and recommendations with respect to the compliance and directives process for

implementation before the next GRA, to assist in improving the effectiveness and efficiency of the overall rate-setting process.