

PUBLIC UTILITIES BOARD

WRITTEN FINAL ARGUMENT OF MANITOBA HYDRO

2017/18 & 2018/19 GENERAL RATE APPLICATION

February 5, 2018



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14.1 Legislative Assembly of Manitoba, Debates and Proceedings, 2nd Session 37th Legislature, May 30, 2001 at page 2505 (Hon. Greg Selinger)	
14.2 <i>Advocacy Centre for Tenants-Ontario v. Ontario Energy Board</i> , 2008 CanLII 23487 (Ont Sup Ct J)	
14.3 <i>Dalhousie Legal Aid Service v. Nova Scotia Power Inc.</i> , 2006 NSCA 74 at paragraph 24, leave to appeal to SCC refused 31627 (January 18, 2007)	
14.4 <i>British Columbia Old Age Pensioners' Organization v British Columbia Utilities Commission</i> , 2017 BCCA 400	
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1 **1. REQUESTED APPROVALS AND SUMMARY OF REASONS FOR THE RATE INCREASES**

2 **1.1 Background and Overview of Approvals Sought**

3 In its 2017/18 & 2018/19 General Rate Application (“GRA”), Manitoba Hydro is seeking
4 final approval of the 3.36% across-the-board rate increases implemented effective
5 August 1, 2016 and August 1, 2017 (approved on an interim basis in Orders 59/16 and
6 80/17), as well as final approval of a 7.9% across-the-board rate increase effective April
7 1, 2018.

8
9 On November 18, 2015, Manitoba Hydro filed its 2016/17 Supplemental Filing seeking
10 approval of an across-the-board rate increase of 3.95% effective April 1, 2016. The
11 review of Manitoba Hydro’s application resulted in Order 59/16, issued April 28, 2016,
12 approving an across-the-board rate increase of 3.36% effective August 1, 2016.

13
14 On May 5, 2017, Manitoba Hydro filed its 2017/18 & 2018/19 GRA seeking approval of
15 rate schedules reflecting an across-the-board rate increase of 7.9% applied to all
16 components of the rates for all customer classes, effective in each of August 1, 2017 and
17 April 1, 2018. As part of its GRA, Manitoba Hydro requested that the PUB approve the
18 rate increase of 7.9% on an interim basis effective August 1, 2017. On July 31, 2017 the
19 PUB issued Order 80/17 approving an across-the-board rate increase of 3.36% effective
20 August 1, 2017.

21
22 In addition, Manitoba Hydro’s GRA is seeking approval of the following:

- 23 • Final approval of the Light Emitting Diode (“LED”) rates for the Area and
24 Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order
25 79/14, and approval of new LED rates for the Area and Roadway Lighting class
26 (Sentinel Lighting), and approval to remove the Area and Roadway Lighting
27 (Festoon Lighting) and the Area & Roadway Lighting (Christmas Lighting) from
28 Manitoba Hydro’s rate schedule. Manitoba Hydro’s evidence on this topic is
29 contained in Tab 9 of the Application. PUB Counsel touched briefly on these
30 topics, however, no intervenors have addressed the topic during the evidentiary
31 portion of the proceeding;
- 32 • Endorsement of modifications to the Terms and Conditions of Option 1 of the
33 Surplus Energy Program (“SEP”) that were accepted on an interim basis in Order
34 43/13, as outlined in Tab 9 of the Application;

- 1 • Final approval of all SEP interim ex parte rate Orders as set forth in Tab 10 of this
2 Application, as well as any additional SEP ex parte Orders as set out in Appendix
3 17.1 to Manitoba Hydro's Written Final Argument and issued subsequent to this
4 filing and prior to the PUB's Order in this matter;
- 5 • Final approval of Curtailable Rate Program ("CRP") ex parte Order 54/16 as well
6 as any additional ex parte Orders in respect of the CRP issued subsequent to this
7 filing and prior to the PUB's Order in this matter;
- 8 • Endorsement of the proposed deferral and subsequent amortization of costs
9 incurred with respect to the Conawapa Generating Station project, as discussed
10 in Tab 3 of Manitoba Hydro's Application; and
- 11 • Endorsement of the proposed amortization period for disposition of the
12 regulatory deferral accounts established to capture differences between
13 overhead costs as well as gains and losses on disposition of assets calculated for
14 financial reporting purposes based on International Financial Reporting
15 Standards, and the amounts calculated for rate-setting purposes reflecting Order
16 73/15. Further details are outlined in Section 17.
- 17 • Endorsement of the proposed time frame for the recognition into revenue of the
18 Bipole III deferral account established by Manitoba Hydro consistent with the
19 direction provided by the PUB in Order 43/13. Further details are outlined in
20 Section 17.
- 21 • Manitoba Hydro is not seeking final approval of the amortization period for the
22 disposition of differences in depreciation methodology at this time. Manitoba
23 Hydro is supportive of finding an alternate process where the requirements of
24 the depreciation directives as set out in Order 43/13 can be discussed and
25 resolution of this issue can be achieved. Further details are outlined in Section
26 17.

27
28 Manitoba Hydro notes that it is not seeking final approval of Orders 17/04,
29 46/04,/159/04, 176/04, 1/10, 134/10, 1/11, 148/11, 116/12 or 117/12 related to various
30 interim Diesel Zone Orders. Manitoba Hydro's initial request set out in its Letter of
31 Application filed on May 5, 2017 was made subject to confirmation that MKO has
32 provided the parties to the Diesel Settlement Agreement with the required affidavits
33 from representatives of signatories to the Agreement. Such confirmation has not been
34 filed in this proceeding.

35

1 Manitoba Hydro accepts that it is difficult to impose a further rate increase to recover
2 the shortfall in revenue arising from the difference between the requested 7.9% interim
3 rate increase requested for August 1, 2017 and the interim rate increase of 3.36%
4 approved by the PUB in Order 80/17 (Transcript page 805-806). As such, consistent
5 with the evidence of both Kelvin Shepherd and Jamie McCallum, Manitoba Hydro is not
6 seeking additional rate increases for fiscal 2017/18, recognizing the impact of the
7 requested rate increase on consumers.

8 9 **1.1 Organization of the Final Argument**

10 Manitoba Hydro's Final Argument is organized as follows:

- 11 • Section 1 provides an overview of the approvals requested in the 2017/18 &
12 2018/19 GRA;
- 13 • Section 2 provides an overview of the facts supporting Manitoba Hydro's requested
14 7.9% rate increase;
- 15 • Section 3 provides an overview of Manitoba Hydro's financial plan, the role and
16 ownership of equity and why a 20-year plan to address the Corporation's financial
17 condition does not work;
- 18 • Section 4 outlines the reasons for the deterioration in Manitoba Hydro's financial
19 outlook;
- 20 • Section 5 provides an overview of the significant increase in debt levels and
21 exposure to interest rate risk, and the need for rate increases in order to meet
22 financial targets;
- 23 • Section 6 provides an overview of Manitoba Hydro's financial targets and the role of
24 reserves in managing Manitoba Hydro's risks;
- 25 • Section 7 outlines the limited value of long-term forecasts and the myth of
26 "promised" 3.95% rate increases;
- 27 • Section 8 outlines the reasons for the decrease in projected revenues, including an
28 overview of the load forecast, export revenues and price forecast, and interest rate
29 outlook;
- 30 • Section 9 provides an overview of business operations capital, Manitoba Hydro's
31 plans regarding asset management initiatives, and a response to recommendations
32 for additional regulatory oversight;
- 33 • Section 10 outlines Manitoba Hydro's position with respect to various issues related
34 to the Keeyask Generating Station, Bipole III, Manitoba-Minnesota Transmission
35 Line, and the Great Northern Transmission Line;

- 1 • Section 11 outlines Manitoba Hydro’s debt management strategy and the
2 importance of cash flows generated through rate increases;
- 3 • Section 12 provides an overview of Manitoba Hydro’s Operating & Maintenance cost
4 reduction measures, and Manitoba Hydro’s response to recommendations related
5 to performance metrics;
- 6 • Section 13 provides Manitoba Hydro’s position regarding the evidence on rate
7 increases on the Manitoba Economy;
- 8 • Section 14 provides an overview of Manitoba Hydro’s initiatives to address bill
9 affordability;
- 10 • Section 15 provides Manitoba Hydro’s response to Cost of Service and rate design
11 issues raised during the proceedings;
- 12 • Section 16 outlines why Manitoba Hydro’s requested rate increases do not
13 constitute rate shock; and,
- 14 • Section 17 provides an overview of the approvals requested with regards to
15 regulatory deferral accounts and the finalization of PUB Interim Orders.

1 **2 A 7.9% RATE INCREASE CANNOT BE WRONG**

2 **2.1 Manitoba Hydro Needs the Rate Increases Requested in this Application**

3 It is essential that the 7.9% rate increase that Manitoba Hydro has requested for April 1,
4 2018 be approved. There has been no evidence presented that contradicts the necessity
5 of this increase. Regardless of conclusions on the appropriate capital targets and timing
6 for achievement, on a cost recovery basis the present and immediate future
7 circumstances of Manitoba Hydro give the PUB ample justification for an even greater
8 increase to current rates than Manitoba Hydro is requesting for the 2018/19 fiscal year.

9
10 The requested April 1, 2018 rate increase is supported by the facts discussed in the
11 following sections.

12
13 **2.1.1 Bipole III Reliability Project Entering Service**

14 The April 1, 2018 rate request of 7.9% is justified on the basis that it will not even
15 address the entirety of the increase to Manitoba Hydro’s revenue requirement due to
16 the imminent in-service of Bipole III.

17
18 The Bipole III Reliability Project enters service in August 2018, which is less than six
19 months following the conclusion of the hearing. Bipole III is an essential and necessary
20 addition to Manitoba Hydro’s system to ensure continued reliability. Bipole III adds
21 effectively no revenue to the Manitoba Hydro system. No evidence has been presented
22 disputing that the incremental carrying costs of this capital addition are properly added
23 to revenue requirement to be borne by current ratepayers.

24
25 The incremental revenue requirement from Bipole III is substantial. PUB MFR 20 shows
26 annual incremental revenue requirement (excluding amortization of the Bipole III
27 reserve) of over \$360 million per year. As shown in Manitoba Hydro’s Written Rebuttal
28 Evidence, page 31 (Exhibit MH-52), net of additional opportunity export revenues of \$15
29 million from reduced line losses and depreciation of \$20 million for the in-service Riel
30 AC sectionalisation, the ongoing carrying costs of Bipole III are estimated to be
31 approximately \$332 million per year. Manitoba Hydro’s domestic revenue in the nearly
32 complete 2017/18 test year is estimated at \$1,464 million net of rates allocated to the
33 Bipole III reserve. On this basis, a 22.7% rate increase would be required to meet the
34 incremental costs.

1 Current approved rates however include 11.1% of past increases which are being
2 allocated to the Bipole III reserve account (inclusive of the August 1, 2017 3.36% interim
3 increase as directed in Order 80/17). Therefore, upon in-service of Bipole III, Manitoba
4 Hydro will begin to recognize in domestic revenue this portion of current rates. This
5 incremental revenue will only offset approximately half of the incremental revenue
6 requirement. An additional rate increase of approximately 10% is required in order to
7 maintain cost recovery from current ratepayers. The requested 7.9% rate increase falls
8 short of meeting this need.

9
10 In oral testimony (Transcript Page 6417, Lines 9-16), Mr. Bowman made the following
11 statements:

12
13 *“...we already have customers paying somewhere between 11 and 12 percent*
14 *towards the Bipole project even though it's not in service. The first time I heard*
15 *the idea, I wasn't favourable to it. I think in hindsight it was a very wise move by*
16 *this Board and it's help phase that in and, as a result, **when Bipole comes into***
17 ***service there's very little more impact into rates that's isn't already built in.”***

18 (Emphasis Added)

19
20 Mr. Bowman's erroneous assertion is based on his flawed analysis included in response
21 to MH/MIPUG-6. Mr. Bowman includes in his analysis the benefit of amortization of the
22 Bipole III reserve in determining the necessary rate increase over and above the 11.1%
23 already embedded in today's rates. This is not appropriate. Manitoba Hydro corrected
24 his analysis in on pages 30 to 31 of Exhibit MH-52 and it is reproduced below. The
25 amortization of the Bipole III reserve reflects the accounting treatment of past rates
26 paid already imbedded in the rate increases being deducted in determining incremental
27 rate requirement. Mr. Bowman is effectively “double counting”. Moreover, the
28 amortization is non-cash and unsustainable. It reflects a five year amortization of cash
29 already received.

30
31 The Figure below (Figure 1.18 from Exhibit MH-52) compares Mr. Bowman's assertions
32 to the corrected analysis which clearly supports at least a 7.9% rate increase solely in
33 contemplation of the near immediate in-service of Bipole III.

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Figure 2.1: Bipole III Rate Increases to Recover Revenue Requirement

\$Millions	Restated	
	MH/MIPUG-6 2022	PUB MFR 20 2022
Finance Expense	223	223
OM&A Costs	13	13
Depreciation	107	107
Amortization of BP III Reserve	(71)	(80)
Capital Tax	24	24
	296	287
 Add: Amort of Bipole III Deferral	 71	 80
	367	367
 Less: Revenue assoc. with lower line losses	 (15)	 (15)
Less: Costs assoc. with Riel Stn.	(40)	(20)
Less: Amort of Bipole III Deferral	(71)	-
Annual Bipole III Revenue Requirement	241	332
Bipole III Total Rate Impact	1,595 15.1%	20.8%
 Annual Bipole III Revenue Requirement in Current I 11.12%	 (177)	 (177)
Annual Bipole III Revenue Requirement Shortfall	64	155
Bipole III Revenue Requirement Shortfall to be Recovered in Rates	 4.0%	 9.7%

Source: Exhibit MH-52

2.1.2 Current Rates Not Covering Current Costs and Cash Needs

On a normalized basis, Manitoba Hydro has been experiencing effectively zero or negative net income for several years notwithstanding the growth of its asset base. This means that there has been no contribution to reserves from rates notwithstanding both Manitoba Hydro’s governing legislation and the evidence of Morrison Park Advisors (“MPA”) emphasizing the importance of rates including a contribution to reserves. Even excluding the essential need to make ongoing contributions to reserves, Manitoba Hydro has not been receiving sufficient rate revenue to meet its costs.

The following chart is taken from Manitoba Hydro’s Policy Panel Presentation, Exhibit MH-64:

1

Figure 2.2 Adjusted Net Income/(Loss)

(In Millions of Dollars)	2014/15	2015/16	2016/17	2017/18
Net Income Attributable to MH	111	37	53	93
Non-Recurring Gain	-	-	(20)	-
Income Impact of Bipole III Capitalization	(8)	(15)	(32)	(54)
Above Average Water	(70)	(62)	(87)	(35)
Adjustment to Current Outlook	-	-	-	(63)
Restructuring Expenses	-	-	4	50
Adjusted Net Income/(Loss)	33	(40)	(82)	(9)

2

3

Source: Exhibit MH-64, Slide 44

4

5

As shown in Figure 2.2, excluding the impacts of non-sustainable contributions such as above average water flows, Manitoba Hydro is in a loss-making position at current rates.

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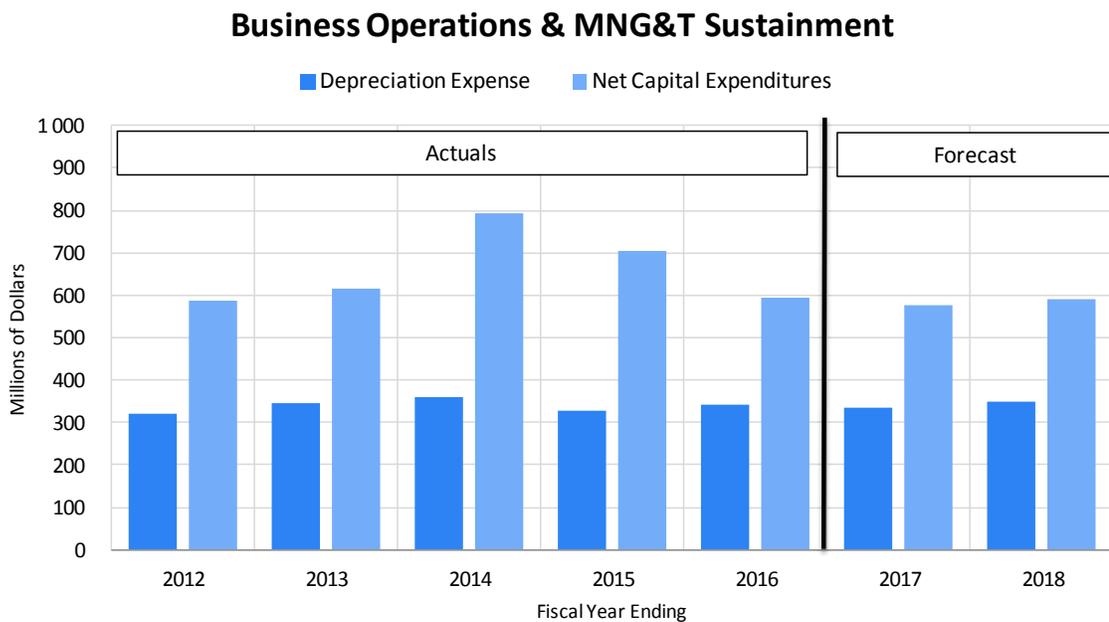
Manitoba Hydro has additional ongoing (often perpetual) payment obligations each year on account of mitigation liabilities and the purchase of Winnipeg Hydro that are only minimally captured in revenue requirement through depreciation expense. Both MPA (MH/Coalition (MPA)-2(b)) and Mr. Bowman (at Transcript Page 6398) acknowledge these costs that must be included in the calculation of rates. As noted in Figure 1.10 on page 15 of Exhibit MH-52, these obligations totaled \$42 million in 2015/16, \$39 million in 2016/17 and are estimated at \$75 million in 2017/18. Adding these costs to revenue requirement pushes the deficiency at current rates to between \$84 million and \$120 million over the last three years. On its own this would support a rate increase of approximately 6% to 7% simply to restore rates to where Manitoba Hydro is meeting its revenue requirement needs as determined by the income statement and ongoing liability payments associated with its current operations and without any contribution to reserves.

Manitoba Hydro submits that the PUB should not ignore the actual cash needs of Manitoba Hydro to continue its current operations. Some accounting in rates must be made for the fact that the actual replenishment costs of the system are significantly greater than what Manitoba Hydro current recognizes in revenue requirement through depreciation expense.

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In order to meet its mandate to serve existing customers and extend service to new customers, Manitoba Hydro must continually reinvest in its system. Significant portions of Manitoba Hydro’s current infrastructure were built decades ago. Manitoba Hydro has provided evidence at Tab 2 of the Application, pages 15 and 18 (reproduced below) that it has a material ongoing cash shortfall at present rates due in part to a substantial difference - over \$250 million a year - between what it recovers in revenue requirement through annual depreciation charges and what it must expend annually to maintain, replace and enhance existing infrastructure in the normal course. The issue is that depreciation expense is determined based on the historical cost of assets when they were first installed. Manitoba Hydro’s reality is that the cost of replacing these assets as they expire is an ongoing cash need that comes in the form of today’s costs which, due to the age of its infrastructure and inflation in construction costs, bears almost no relationship to historical cost.

Figure 2.3



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Source: Tab 2 of the Application, Page 15

Arguments opposing accommodating in rates the need to replenish the system are not valid. The suggestion that the cost of replacement equipment, while substantially more than the original cost of the assets being replaced, will be recovered in depreciation

1 over the life of the assets ignores cost and capital structure realities faced by the
2 Corporation. Rate-making principles will be referenced in support of that argument.
3 However, the principles cited are only sustainable in a rate of return based
4 environment, not a cost recovery environment. A rate of return framework allows the
5 utility to maintain adequate equity capitalization such that it does not need to increase
6 only its debt simply to fund its operations. Manitoba Hydro has no such luxury. Without
7 the support of rate revenue (i.e. net income and contribution to reserves), all
8 investment in the ongoing core system in excess of depreciation expense must be debt
9 funded which has, and will continue to, drive the debt of the Corporation ever higher at
10 a rate significantly greater than its customer base or domestic load is growing. This is
11 particularly acute in Manitoba Hydro's situation given the stagnant growth environment
12 Manitoba Hydro finds itself in and the age of its asset fleet. Declining interest rates and
13 above average water conditions have helped to obscure this issue but lack of rate
14 support for reinvestment capital has become a critical matter for Manitoba Hydro's
15 finances. In Manitoba Hydro's view, the PUB must consider the current costs of
16 replacing the assets current ratepayers are depleting. A proper reading of the Bonbright
17 principles finds no fault in doing so¹, particularly in the absence of a rate of return
18 principle by which the Corporation can attract capital and remain financially sustainable
19 (also a key Bonbright criterion²).

20
21 Bonbright discusses whether rate base should be set at historical cost less depreciation,
22 or at some proxy for replacement value noting that this debate is the "*most widely*
23 *disputed legal issue in the history of American public utility regulation.*"³ Bonbright does
24 not take the position that replacement value based regulation is indefensible as
25 suggested by Intervenors. To the contrary, Bonbright reviews the difficult question of
26 determining value and the relative merits of different approaches, in different
27 circumstances. Manitoba Hydro must wait to see how Intervenors address these various
28 approaches and their application to Manitoba Hydro's unique corporate structure, in
29 their final submissions in order to make informed comment. At this juncture, Manitoba
30 Hydro would argue that all Bonbright requires is that the application of his various and
31 sometimes competing principles be guided by the overarching public interest principle

¹ Principles of Public Utility Rates, James C. Bonbright, 1961, Chapters 11, 12 and 15.

² Principles of Public Utility Rates, James C. Bonbright, 1961, page 385.

³ Principles of Public Utility Rates, James C. Bonbright, 1961, page 159.

(Bonbright's "assumed goal of ratemaking"⁴), and that the application of regulatory principles should never cause a utility to become financially unstable.

When the actual cash costs of replacing system assets are properly considered, a picture of substantial cash deficiency emerges as shown at page 15 of Exhibit MH-52, Figure 1.10, reproduced below:

Figure 2.4 Cash Flow (Deficiency)/Surplus

millions of dollars

	Actual		Forecast									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Receipts from Customers	1 907	1 997	2 152	2 170	2 173	2 371	2 577	2 734	2 821	2 931	2 897	3 011
Payments to Suppliers and Employees	(736)	(933)	(892)	(843)	(870)	(885)	(894)	(903)	(935)	(953)	(952)	(966)
Interest Paid (Net of All Capitalized Interest)	(520)	(536)	(528)	(641)	(711)	(789)	(889)	(1 155)	(1 227)	(1 239)	(1 241)	(1 266)
Bipole III and Other Business Operations Capitalized Interest*	(107)	(141)	(197)	(93)	(21)	(18)	(16)	(19)	(19)	(19)	(18)	(20)
Business Operations and Deferred Capital Expenditures:												
Business Operations Capital Expenditures**	(616)	(578)	(586)	(566)	(554)	(544)	(525)	(532)	(544)	(601)	(627)	(646)
Demand Side Management	(54)	(50)	(55)	(97)	(92)	(87)	(85)	(64)	(58)	(60)	(64)	(68)
Mitigation and Other Deferred Expenditures	(22)	(5)	(27)	(26)	(23)	(23)	(22)	(22)	(21)	(22)	(21)	(22)
Ineligible Overhead	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	-	-	-	-
Cash From Operations Less Capex	(167)	(267)	(153)	(116)	(119)	5	126	19	16	38	(26)	24
Mitigation, Major Development & Other Liability Payments	(26)	(13)	(59)	(46)	(36)	(79)	(98)	(88)	(84)	(84)	(71)	(70)
City of Winnipeg Payments	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Cash Flow (Deficiency)/Surplus	(209)	(296)	(228)	(178)	(170)	(89)	12	(85)	(84)	(62)	(113)	(62)
Cumulative Cash Flow (Deficiency)/Surplus			(228)	(406)	(576)	(665)	(653)	(739)	(823)	(884)	(998)	(1 060)

*Bipole III and Other Sustaining Capitalized Interest does not include any capitalized interest associated with Keeyask, MMTP or GNTL.

**Represents Business Operations Capital Expenditures and MNG&T Capital Expenditures of a sustaining nature (excluding Bipole III costs).

Source: Exhibit MH-52, Page 52

The projections above are based on MH15 rates (i.e. 3.95% per year) for 2019 and beyond. However, the table clearly denotes that Manitoba Hydro has, in the last two years and the current year, been operating with a cash deficiency of between \$153 million and \$267 million. This alone would represent rate inadequacy of 10% to 18%. Adding the above noted costs for liability payments (mitigation, City of Winnipeg) brings the deficit range from \$209 million to \$296 million indicating rate insufficiency of approximately 14% to 20%. The results for 2015/16 and 2016/17 include the contributions from significantly above average water flow conditions. Likewise, the figures above for the 2017/18 and 2018/19 fiscal years assume high water flow conditions and have not been adjusted for Manitoba Hydro's updated outlook after a relatively dry summer. Manitoba Hydro has provided evidence (Exhibit MH-64, Slide 19)

⁴ Principles of Public Utility Rates, James C. Bonbright, 1961, Chapter 2.

1 that above average water flow conditions contributed \$62 million and \$87 million in
 2 2015/16 and 2016/17 respectively and, in the MH16 Update with Interim forecast, were
 3 anticipated to contribute \$91 million in 2017/18. Cash flows should also be adjusted for
 4 non-recurring restructuring charges. Together, this pushes the cash deficit from
 5 operations, on a normalized basis, to between \$271 million and \$379 million
 6 representing rate inadequacy of between 17% and 25% (as summarized in Figure 2.5
 7 below).

8
 9 **Figure 2.5 Rate Insufficiency**

(\$ millions)	2015/16	2016/17	2017/18
Cash from Operations less capex	(167)	(267)	(153)
Liability Payments	(42)	(39)	(75)
Cash Flow Deficiency	(\$209)	(\$296)	(\$228)
Adjustment for Water Conditions	(62)	(87)	(91)
Restructuring Costs	--	4	50
Normalized Cash Deficiency	(\$271)	(\$379)	(\$269)
Domestic Rate Revenue*	\$1,450	\$1,515	\$1,615
Rate Insufficiency	18.9%	25.0%	16.7%

10 * Including contributions to Bipole III reserve

11
 12 Therefore, by any measure the 7.9% rate increase requested for April 1, 2018 is justified
 13 by the need to address rate inadequacy today.

14
 15 **2.1.3 Impact of Keeyask on future cost structure must be taken into consideration**

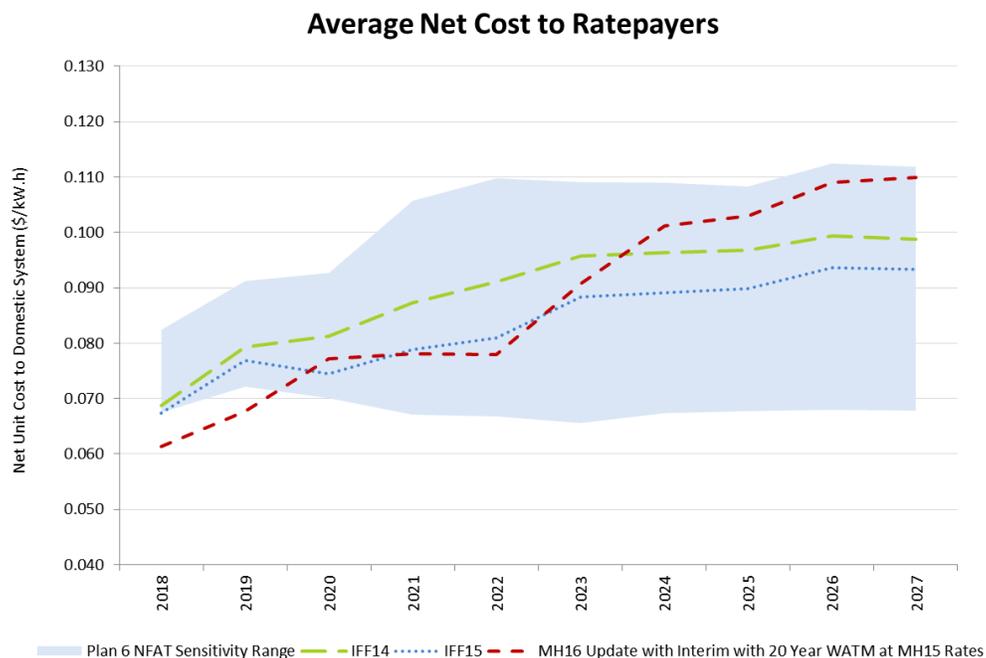
16 The Keeyask Generating Station is anticipated to provide first power in August of 2021
 17 and be essentially fully in-service by the end of the 2022/23 fiscal year. Once this
 18 occurs, the incremental revenue, operating and carrying costs will impact Manitoba
 19 Hydro revenue requirement. Unfortunately, based on the current capital cost estimate
 20 and outlook for export prices, it is anticipated that the net impact to Manitoba Hydro's
 21 revenue requirement going forward will be negative and substantial. As identified in
 22 PUB MFR 20, the 2023/24 incremental costs of Keeyask will be \$581 million which is
 23 anticipated to be more than double the incremental export revenue assuming normal

1 water conditions. The erosion of forecast load growth since NFAT has now pushed the
2 date at which Keeyask is required to serve domestic load until at least the early 2030s.
3 Given the outlook for export prices there results a significant cost for excess capacity
4 which must be borne by ratepayers.

5
6 Manitoba Hydro asserts that the PUB, as it wisely did with Bipole III, must take a strong
7 step now by approving the 7.9% rate request so as to begin incorporating into rates the
8 pending impact of Keeyask. This is particularly so given the risk of further capital cost
9 increases, the loss of an assumed major new load due to an energy sector project
10 cancellation and further delayed recovery of export prices. Manitoba Hydro has
11 provided testimony on these factors, none of which are reflected in MH16 Update with
12 Interim.

13
14 The following chart from slide 70 of Exhibit MH-64 reflects net unit costs (costs net of
15 export revenues) on a forecast basis:

16
17 **Figure 2.6**



18
19 **Source: Exhibit MH-64, Slide 70**

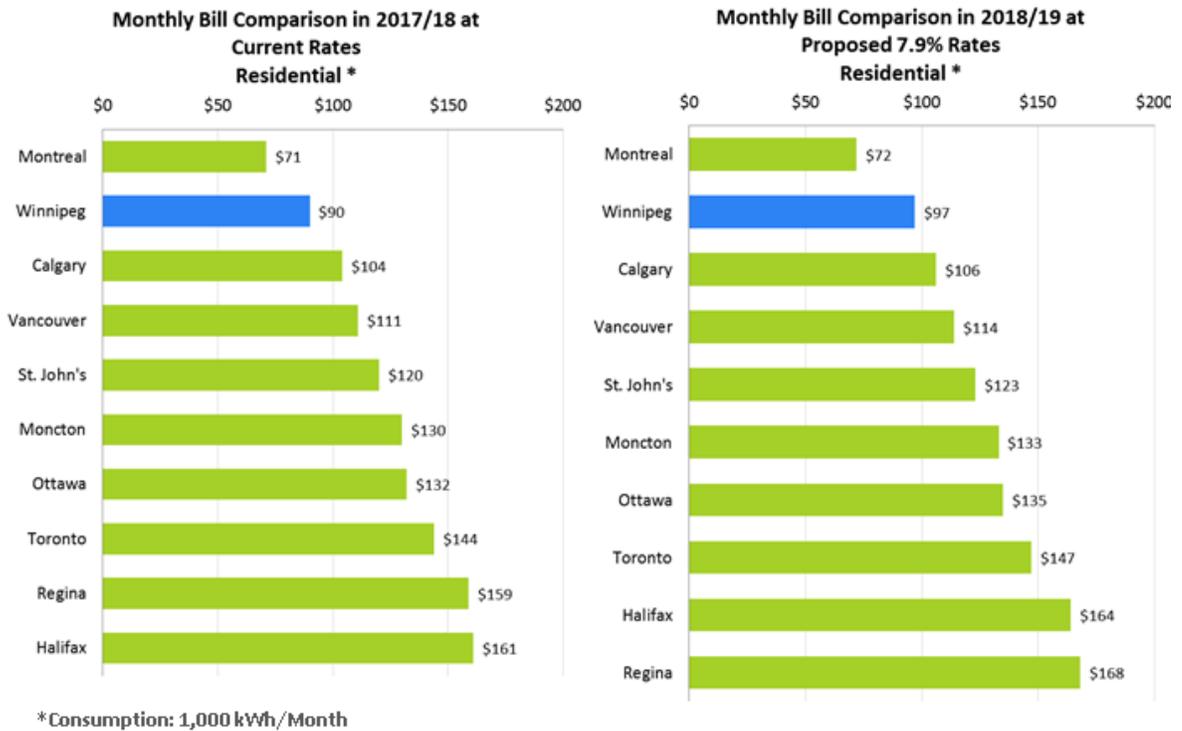
1 As can be seen above, unit costs are increasing sharply over the next six years driven by
2 the in-service of the major capital projects. As demonstrated in Figure 1.1 of MH Exhibit
3 52 at page 2, net costs are estimated to increase 65% between 2017/18 (\$0.061 per
4 kWh of domestic load) and 2023/24 (\$0.100 per kWh). It should be recognized that net
5 unit costs do not include any contribution to reserves which might address capital
6 renewal, debt retirement and rate stability. It is this net unit cost Manitoba Hydro must
7 presumably, at a minimum, recover in rates. A 65% rate increase over six years is
8 equivalent to 8.7% per year. On this basis, a first step of 7.9% as requested for April 1,
9 2018 is fully justified. It may even prove inadequate considering some of the potential
10 risks to unit costs from the more up-to-date outlook for load growth and export prices
11 and ongoing risks with Keeyask capital costs.

12 13 **2.1.4 Electricity Rates will continue to be Competitive**

14 Manitoba Hydro's domestic electricity rates are among the lowest in North America and
15 support the competitiveness of Manitoba businesses. Manitobans will continue to enjoy
16 a distinct advantage over most other Canadian jurisdictions with respect to the average
17 monthly bills of residential and business customers. As shown in **Figure 2.7** (Exhibit MH-
18 64, Slide 12) and **Figure 2.8** below (Exhibit MH-64, Slide 13), this advantage continued
19 after implementation of the 3.36% effective August 1, 2017 and will continue with the
20 proposed 7.9% rate increase effective April 1, 2018.

1

Figure 2.7

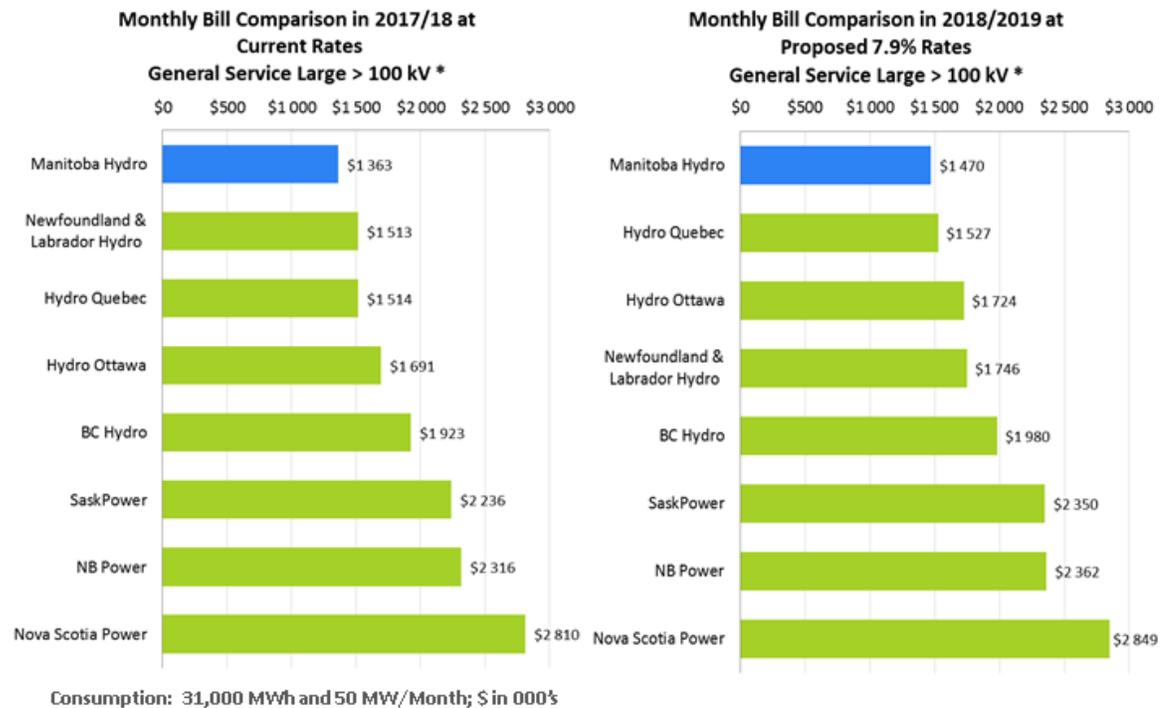


2

3

4

Figure 2.8



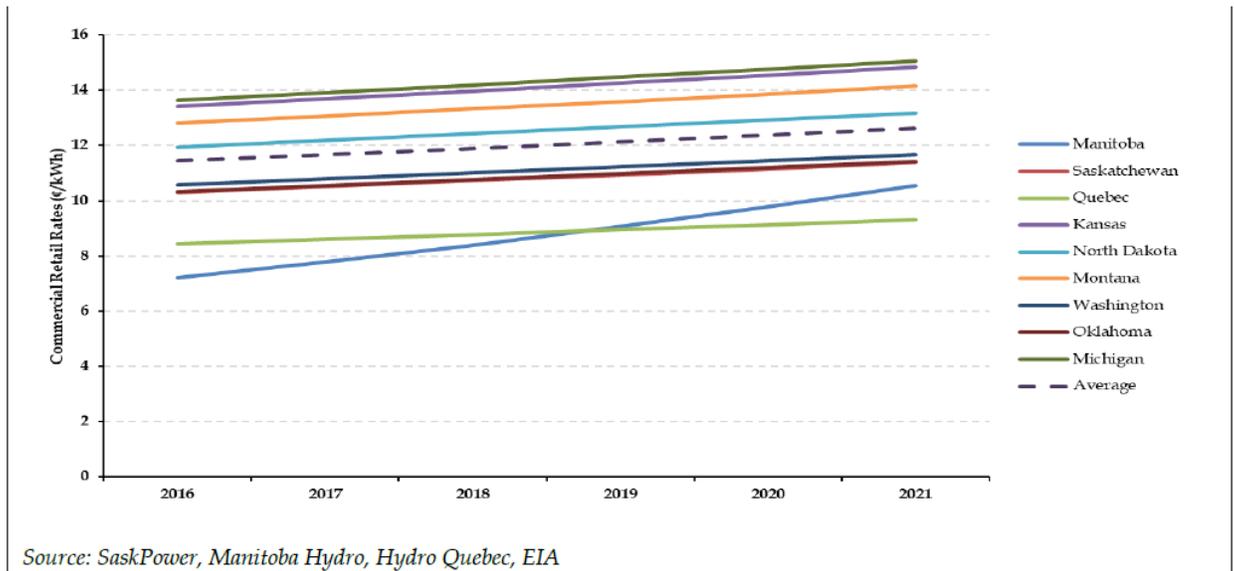
5

6

1 The reality of rate increases above inflation is not confined to Manitoba customers. As
 2 noted by Mr. Shepherd at Transcript Page 145, “broadly speaking, electricity costs are
 3 going up at rates higher than inflation as utilities throughout North America grapple
 4 with changing demand patterns, higher regulatory costs, aging infrastructure, and for
 5 many, the transition from carbon generating sources to renewables.” While Manitoba
 6 Hydro is seeking rate increases in this proceeding that are above the rate of inflation,
 7 the evidence demonstrates that Manitoba customers will continue to be in a much
 8 better position in terms of electricity costs than customers in other jurisdictions, and
 9 that rates have considerable room to grow before Manitoba Hydro becomes even an
 10 average jurisdiction.

11
 12 This is further demonstrated by the evidence provided by London Economic
 13 International (“LEI”) in this proceeding. While LEI suggests in its evidence, filed on behalf
 14 of General Service Small and General Service Medium Customer Classes, Exhibit GSS-9,
 15 at page 16 that annual rate increases of 7.9% over five years will erode Manitoba
 16 Hydro’s competitive margin on commercial rates compared to other jurisdictions, the
 17 same figure demonstrates that Manitoba Hydro will continue to be in the lowest
 18 quartile of commercial retail rates even after five years of indicative 7.9% rate increases.
 19

20 **Figure 2.9. Commercial retail rates of Manitoba compared to other jurisdictions**



21
 22

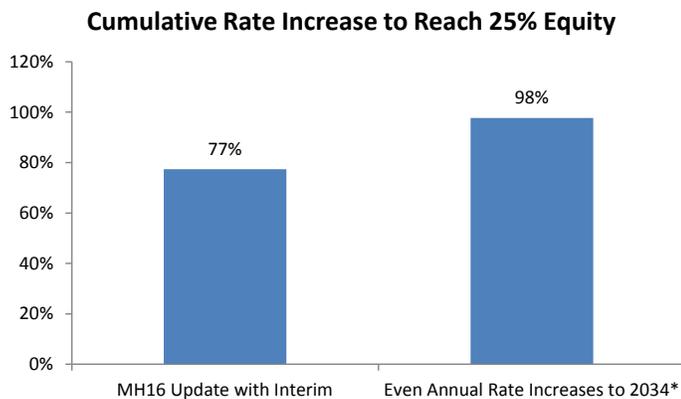
1 **3 MANITOBA HYDRO'S NEW FINANCIAL PLAN**

2 **3.1 Taking Action on Unsustainable Debt Levels**

3 Manitoba Hydro's new financial plan is necessary to ensure the financial sustainability of
4 the Corporation. In doing so it ensures that, in the intermediate and long-term,
5 customers will benefit from more rate certainty, less rate volatility and overall lower
6 rates. While short term adjustment is required, the broader Manitoba economy
7 benefits from a higher level of long term cost certainty for existing and new businesses
8 considering investment in addition to the certainty of lower rates in the long term
9 relative to plans that see Manitoba Hydro carrying a larger debt burden and for longer.

10
11 Manitoba Hydro's plan represents an acceleration of rate increases but, overall, the
12 ability to keep rates lower in the long run as seen in **Figure 3.1** below:

13
14 **Figure 3.1 Even Annual Rate Increases of 4.14% To Reach 25% Equity Ratio By 2033/34**



15 **Source: Coalition/MH II-19,**

16
17
18 Manitoba Hydro's plan is centered on taking action on the growth of debt to
19 unsustainable levels. It does so by setting a rate plan which, when coupled with far
20 more aggressive cost efficiency measures already implemented by Manitoba Hydro,
21 enables the Corporation to generate positive net income and positive cash flow which
22 can be used to modestly slow the accumulation of debt while Keeyask is completed and
23 reduce debt once the project is in service. By taking more aggressive action now and
24 over the next decade, the following is achieved:

1 **3.1.1 Greater flexibility**

2 MH16 Update with Interim is a financial plan based on numerable assumptions. It is a
3 balanced best estimate of an unknowable future. The value of taking stronger rate
4 action now is to provide greater flexibility to make different choices as the future
5 unfolds.

6
7 The pattern of prior forecasts demonstrates a history of successive downward revisions
8 to export price expectations and load growth forecasts. Likewise, expectations of
9 capital costs have increased. The situation has not become more dire only by virtue of
10 interest rates having declined in comparison to prior outlooks and the benefits of 14
11 years of higher than average water flows.

12
13 By implementing stronger rate action now, Manitoba Hydro is building its balance sheet
14 to be more resilient in the face of uncertainty. As noted by Mr. Shepherd, Manitoba
15 Hydro has more hydrology and export price risk than any other Crown-owned, hydro-
16 based utility:

17
18 *“No other major hydroelectric utility has the volatility in water conditions we*
19 *face, nor does anyone else have such a small reservoir relative to their*
20 *operations. Our exposure to mother nature in that respect is quite extreme. By*
21 *just about any measure, we are heading towards having more debt than almost*
22 *anyone else in our industry, and certainly more debt relative to the size of our*
23 *business than potentially we have ever had”* (Transcript Page 196).

24
25 Mr. Shepherd further noted that while not exposed to fuel price volatility similar to a
26 coal or natural gas utility, by financing itself in such an extreme manner, Manitoba
27 Hydro is effectively replacing commodity price volatility with interest price volatility:

28
29 *“We can't borrow at a fixed rate for the seventy (70) or a hundred years our*
30 *generators are expected to last, so we are perpetually exposed to interest rate*
31 *risk, all of which is borne by a relatively small customer base”* (Transcript Page
32 196)

33
34 The risks Manitoba Hydro needs net income and positive cash flow to address are not
35 theoretical. Rising interest rates, softening export prices, slower load growth and low

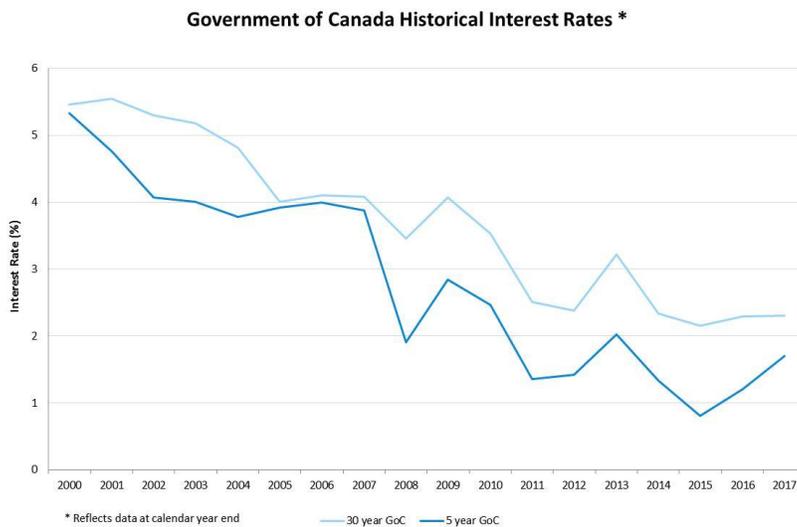
1 water conditions have all been experienced before. A financial plan that does not
2 include meaningful net income (relative to the scale of the assets and debt) offers no
3 flexibility for the utility and its regulator to consider measured, patient responses to key
4 planning assumptions being wrong.

6 **3.1.2 Lessening interest rate risk**

7 Annual interest payments will be, by a factor of two, the single largest burden on the
8 Corporation by 2023/24. Even under the Manitoba Hydro plan, interest costs will
9 consume \$1.14 billion per year as shown in Appendix 3.8 of the Application. Current
10 domestic rate revenues are \$1.6 billion (including amounts allocated to the Bipole III
11 reserve). Therefore without rate increases, interest will consume approximately 70% of
12 each ratepayer dollar. With this level of interest expense relative to overall costs and
13 revenues, Manitoba Hydro has no latitude to be wrong on interest rates.

14
15 As the **Figure 3.2** shows, interest rates have declined significantly since 2000:

16
17 **Figure 3.2**



18
19 **Source: Exhibit MH-64, page 68**

20
21 With interest rates at multi-generational lows already and practically speaking unable to
22 go to 0%, it is clear that the risks of interest rate volatility are asymmetrical in nature.
23 There is an extremely limited amount by which rates can go down further and an
24 unlimited potential for increase. Exposing the Corporation, its customers and the

Province of Manitoba to this level of risk over 20 years is imprudent. History has shown – as does the chart above – that interest rates can often move 3 to 5% or more in a 10 or 15 year period. Almost all of Manitoba Hydro’s debt is exposed to interest rate risk over the next 10 years (Manitoba Hydro’s Written Rebuttal Evidence, Exhibit MH-52, Pages 11 to 14). An unforeseen interest rate increase of even 1% could cost Manitoba Hydro ratepayers an additional \$200 million or more per year by the end of the next decade. A more focused approach to debt reduction helps mitigate part of this risk.

Address cash flow

While noting the apparent migration in views since NFAT (CAC/MPA I-002), Morrison Park Advisors (“MPA”) asserts that cash flow is the principle concern of capital market participants in assessing Manitoba Hydro (in the context of their rating of the credit quality of the Province of Manitoba). As noted in MPA Evidence filed on behalf of the Consumer’s Coalition, Exhibit CC-17, page 3, lines 35-37:

“It is apparent from reading various financial market reports that a primary focus is on the expected sufficiency of cash flows to satisfy debt obligations.”

Coalition/MH I-68f includes a cash flow from operations to CapEx table which updates Figure 2.16 from the Tab 2 of the Application for MH16 Update with Interim. That table only captures a portion of the cash flow deficiency in that payments on account of mitigation and City of Winnipeg liabilities are not captured. The following table in **Figure 3.3** augments Figure 2.16 (Updated) from Coalition/MH I-68f.

Figure 3.3

(\$ millions)

Cash Flow Deficiency / Surplus
 Mitigation, Major Development & Other Liability Payments
 City of Winnipeg Payments
Cash flow from Operations
Cumulative Cash Flow Deficiency / Surplus

MH16 Update with Interim				
2018	2019	2020	2021	2022
(151)	(35)	49	269	501
(59)	(46)	(36)	(79)	(98)
(16)	(16)	(16)	(16)	(16)
(226)	(98)	(2)	174	387
(226)	(324)	(326)	(152)	235

Source: Coalition/MH I-68f

The analysis above shows that the Manitoba Hydro plan takes a prudent, measured and multi-year approach to addressing the ongoing cash flow shortfall the Corporation is enduring at current rates. In the fourth year of the plan, Manitoba Hydro returns to a

1 cash flow positive condition. However, for the first five years of the plan, in aggregate
2 Manitoba Hydro is essentially cash flow breakeven with only a modest \$235 million
3 being made available for debt reduction. This amounts to approximately 1% of
4 Manitoba Hydro's forecast net debt of \$23.6 billion in 2022 under the MH16 Update
5 with Interim rate path.

6
7 Operating for at least three years with continued negative cash flow and taking five
8 years to be cumulatively breakeven is, in Manitoba Hydro's assessment, at the outer
9 bounds of credible as a commitment to having ratepayers meet the obligations of
10 operating the utility and servicing its debts. The recent past has shown that outlooks
11 can change and deteriorate quickly. In that context and in a quickly evolving utility
12 industry, a willingness to endure multi-year cash flow shortfalls should not be expected
13 to be well received by the debt investors who Manitoba Hydro seeks to have fund its
14 balance sheet.

15 16 Cap maximum debt at NFAT levels

17 The overall deterioration of the outlook for Manitoba Hydro is discussed at Section 4.
18 However, the consequence of the increase in capital costs, reduction in load growth and
19 weaker export pricing is that net debt levels will peak at significantly higher levels than
20 under any prior forecast (as shown in Manitoba Hydro Follow-up to Undertakings 7 & 8,
21 Exhibit MH-93, Page 14).

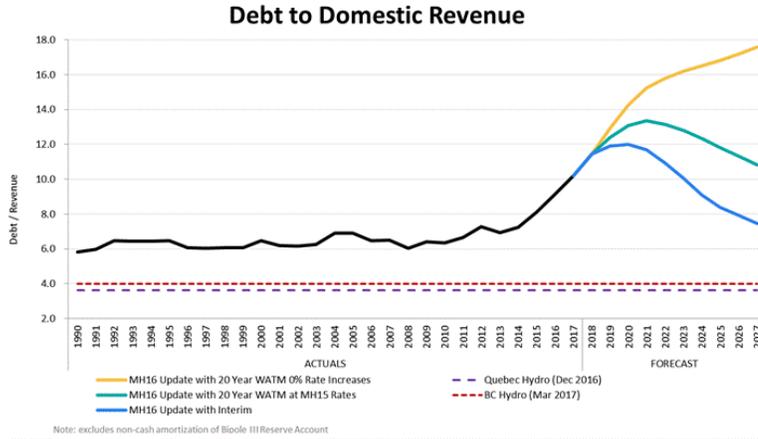
22
23 The Manitoba Hydro plan takes action to address debt growth beyond forecast levels in
24 NFAT. Under the NFAT Plan 5, net debt would peak at \$21.6 billion in 2022/23, roughly
25 three years after the then planned in-service of Keeyask. Under MH16 Update with
26 Interim, the "*Manitoba Hydro Plan*", debt grows to \$23.6 billion which is 9% higher than
27 the NFAT plan. It should be noted that this is to be supported by a domestic load that is
28 expected to be 7% smaller than under the NFAT projection thus compounding the
29 vulnerability of Manitoba Hydro and its customers to a debt that will grow to at least 12
30 multiples of domestic revenues.

31
32 The chart below in **Figure 3.4** from Manitoba Hydro's Policy Panel Presentation (Exhibit
33 MH-64) demonstrates the relationship between debt and revenue dating back to the
34 early 1990's when the Limestone Generating Station was brought into service. Even

1 under the Manitoba Hydro Plan, debt levels will still be, on a relative basis, roughly 30%
 2 higher than they were in the period from 1990 to 2010.

3
 4

Figure 3.4



5
 6

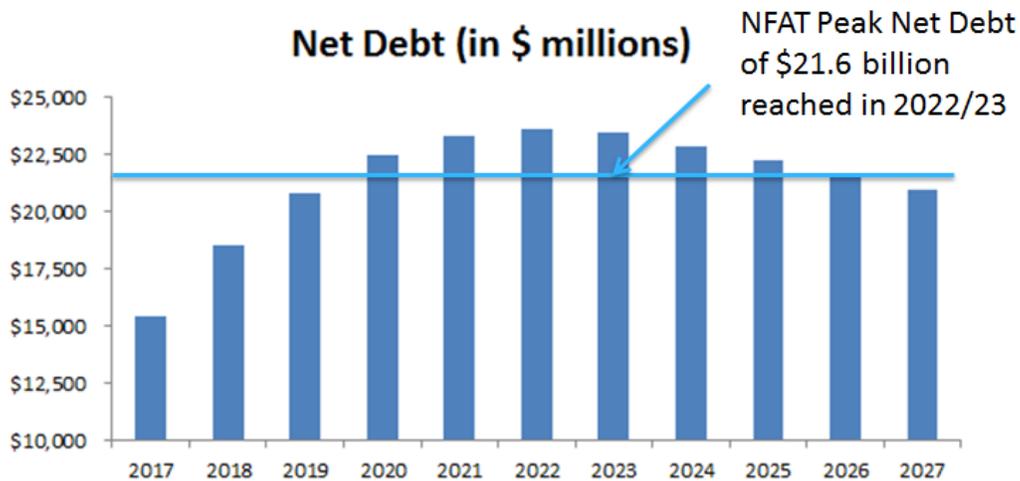
Source: Exhibit MH-64, Page 28

7

8 The chart below in **Figure 3.5** demonstrates how the Manitoba Hydro Plan will restore
 9 debt to levels contemplated under NFAT (Page 14 of Exhibit MH-93) on a longer time
 10 frame (5 years after first in service of Keeyask) than anticipated under NFAT and, as
 11 noted above, still requiring support from a smaller domestic rate base than assumed
 12 under NFAT. The Manitoba Hydro plan takes positive steps toward prudent debt
 13 management but should not by any means be understood to leave the Corporation and
 14 its customers at anything other than very high risk levels.

15
 16

Figure 3.5



17

Source: Appendix 3.8 of the Application, Page 3

Expectation of sub-inflationary increases or better

Manitoba Hydro provided a fulsome discussion of the long-term benefits of proactively addressing Manitoba Hydro’s weak and weakening balance sheet in its response to PUB/MH II-21. A reduction of debt translates to interest expenses avoided which results in reduced revenue requirement relative to plans that do not address unsustainable debt load. While Manitoba Hydro acknowledges its customers pay higher rates during the period of recovery, a residential customer using 1,000 kWh per month would experience lower bills over the period from 2017/18 to 2033/34, as shown in the table below.

Figure 3.6

	25% Equity Ratio <u>Achieved</u>	Cumulative Increase		Average Monthly Bill - 2033/34	Cumulative Bills <u>2017/18 to 2033/34</u>
		<u>To 2026/27</u>	<u>To 2033/34</u>		
PUB/MH II-21b Scenario based on MH16 - Update with Interim	2026/27	77.4%	38.8%	\$121	\$25,173
Coalition / MH II-19 Scenario even annual rate increases to 2033/34	2033/34	48.9%	97.7%	\$172	\$25,881
Difference			-60.3%	-29.9%	-2.7%

Source: PUB/MH II-21

This advantage applies even more so in a rising interest rate environment which has to be expected at some point in the next 20 years if not sooner. With significantly less debt to service and a healthier financial condition, Manitoba Hydro and its regulator will have established the flexibility to consider future rate changes with a then much clearer understanding of load growth, export pricing, interest rates and reinvestment needs for the years beyond 2027 than is available today.

Due to the inherent uncertainty associated with attempting to forecast results in the 2028 to 2036 time frame, it is impossible to predict the measures Manitoba Hydro would propose to abate equity growth to unnecessary levels. However, should Manitoba Hydro find itself in a relatively stable operating environment but with significant capital investment needs on the near to intermediate term horizon, it is reasonable to expect the pace and extent of rate increases necessary to support major renewal and growth investments will be significantly abated by entering this period with a balance sheet and rate levels capable of absorbing incremental debt financing needs.

1 In the alternative, without major expansion or other capital needs during or just beyond
2 the 2028-2036 horizon, rate relief may be affordable and prudent. What ends up being
3 appropriate in terms of rate action 10 or 15 years from now will be a function of events
4 between now and 2027. PUB/MH II-21b demonstrates how dramatically different the
5 future can be where the only difference is the time taken to restore the Corporation's
6 financial health. The long term interests of ratepayers and the economy is served by
7 taking steps today to bring debt back to levels that allow Manitoba Hydro to absorb risk.
8

9 **3.2 Interveners have a Lack of Comprehension with respect to Role and Ownership of** 10 **Equity**

11 Manitoba Hydro's review of Intervener evidence reveals fundamental
12 misunderstandings about the role of equity. A principal argument put forward by MPA
13 and Mr. Bowman (Transcript Pages 4916, and 6420 to 6424) is that Manitoba Hydro's
14 equity need only be scaled in some proportion to the financial erosion anticipated from
15 a five or seven year drought. This argument continues that Manitoba Hydro's plan to
16 build its equity to \$6.9 billion by the end of 2026/27 is excessive in the face of losses on
17 a five or seven year drought that are in the order of \$1.2 billion to \$1.5 billion.
18

19 The reality is that equity is not cash. MPA and Mr. Bowman both acknowledge this
20 (Transcript Pages 5114 and 6382). Mr. Bowman also acknowledges that of Manitoba
21 Hydro's \$2.9 billion of equity, 90% was created more than 5 years ago and 75% was
22 created during and before 2009 (Transcript Pages 6380 to 6382).
23

24 Equity in and of itself is of no useful service to Manitoba Hydro in the event of financial
25 distress. Regardless of the equity recorded on the balance sheet, in the absence of rate
26 adequacy to cover its costs, Manitoba Hydro will have to borrow money or raise rates.
27 Equity is not a reserve funded with cash that can be drawn down to absorb losses. The
28 value of a strong equity balance is it represents debt not borrowed and therefore
29 interest payments that do not need to be made. The notion, put forward by MPA that
30 equity represents Manitoba Hydro's capacity to borrow further and up to the value of
31 its assets (Transcript Page 4859) is preposterous. It suggests there is no consequence to
32 simply adding to the Corporation's debt burden in times of distress, forecast error or
33 otherwise. A fundamental principal of Manitoba Hydro's Application is that debt
34 growth in dollar terms must be curbed.
35

1 The financial risk facing Manitoba Hydro, its customers and the Province of Manitoba is
2 driven by the absolute level of debt on its balance sheet. The customers of Manitoba
3 Hydro are a finite group. \$25 billion of debt represents the actual liability of the
4 Company that must be met with cash payments of interest each year. It is a substantial
5 burden for the customers of Manitoba Hydro to bear regardless of the notional equity
6 balance (which is, in the Corporation's case, an accounting construct representing the
7 aggregate net income of the Corporation since its inception).

8
9 The Interveners are caught in a myopic worldview that drought is Manitoba Hydro's
10 largest financial risk and therefore reserves must only be scaled accordingly. In the
11 short term, drought is Manitoba Hydro's largest potential financial loss. But drought will
12 presumably have an end and therefore the erosion has a limit. Absent the rate
13 adequacy Manitoba Hydro is proposing, a drought will be entirely debt funded and, in
14 the 5 year example, add \$1.2 billion (PUB/MH II-40 Figure 2) to Manitoba Hydro's \$25
15 billion debt. This is dwarfed in comparison by the effectively limitless and perpetual
16 damage that will be delivered upon Manitoba Hydro's ratepayers if steps are not taken
17 to address the \$25 billion debt balance while it is still manageable (i.e. before interest
18 rates rise). If Manitoba Hydro and its customers find themselves on the wrong side of a
19 long-term systemic rise in interest rates, the financial consequences are almost
20 impossible to quantify. As can be seen in the response to MIPUG/MH II-19a, 10 years
21 ago, the Government of Canada long bond yield was 200 basis points (2%) higher than it
22 is today and 20 years ago it was over 500 basis points (5%) higher. On \$25 billion of
23 debt, even a return of interest rates to long term historical averages could cost
24 Manitoba Hydro ratepayers hundreds of millions of dollars per year and, unlike with
25 drought, no expectation of relatively near term abatement.

26
27 Manitoba Hydro's pursuit of the 75:25 Debt:Equity ratio is driven entirely by the need to
28 reduce absolute levels of debt to levels consistent with NFAT (i.e. \$21.5 billion)(Exhibit
29 MH-93) albeit further in the future which presents incremental risk. Were it not for the
30 importance of balancing rate action with customer impacts, more prescriptive action
31 would be advocated.

32
33 The PUB clearly understood the intrinsic relationships between the concepts of the
34 equity ratio, absolute debt levels, financial risk to ratepayers and ratepayer impacts in
35 Order 90/08, pages 3-7:

1
2 *“Notwithstanding the Board’s appreciation of the negative implications of rate*
3 *increases for MH’s customers, and the Board’s particular and on-going concern*
4 *for low-income households, particularly, in this case, those relying on electricity*
5 *for space heating, the Board will provide MH with a greater increase than the*
6 *Corporation sought. This, because of a combination of concerns that are briefly*
7 *cited below, matters the Board will elaborate on in more detail in a subsequent*
8 *Order:*

9
10 *a) In its application, MH advised that its proposed series of 2.9% increases were*
11 *required to maintain progress towards the eventual attainment of the*
12 *Corporation’s financial targets, primarily the achievement of the long-sought but*
13 *not achieved target debt to equity ratio of 75:25. MH projected that*
14 *notwithstanding its forecasts of annual rate increases and the assumption of*
15 *continuing success with export markets, and taking into account forecast net*
16 *income for 2007/09 to achieve or exceed \$300 million, it still did not expect to*
17 *achieve the debt:equity financial target of 75:25 by 2017/18 (let alone the*
18 *current or previous earlier target dates);*

19
20 *Herein, and to be discussed in considerable depth in the subsequent Order, **the***
21 ***Board reconfirms the validity of the targeted debt:equity ratio of 75:25, while***
22 ***expressing concern as to the likelihood of its achievement.***

23
24 *b) MH’s plans for capital expenditures may involve the expenditure of \$18 billion*
25 *or more over the next 15 years, expenditures predicated in part on what may or*
26 *may not be overly optimistic export prices – **this level of capital expenditure will***
27 ***result in significantly increased debt levels, export commitments and general***
28 ***business risks;...***

29
30 *g) **Continuing business risks related to interest rates (now at recent historic***
31 ***lows), the risk of further currency fluctuations, drought, inflation, market access***
32 ***problems, and other concerns...***

1 ***The Board is focused on the risks that lie ahead and determined to ensure as***
2 ***reasonably as possible that MH has the financial strength to meet the risks.***
3 (Emphasis Added)
4

5 MPA's views in this hearing on the value of equity during a drought, as canvassed by Mr.
6 Ghikas during cross-examination of Mr. Colaiacovo at Transcript Page 4992, stand in
7 contrast to views during NFAT when MPA was an Independent Expert Consultant ("IEC")
8 to the PUB. At that time its concern with debt levels was more apparent as noted at
9 CAC/MPA I-013
10

11 *"The critical issue is the magnitude of outstanding debt on the balance sheet, not*
12 *the size of the retained earnings. In the event of a persistent revenue shortfall*
13 *caused by prolonged drought, for example, interest charges related to a large*
14 *outstanding debt represent a real call on cash flow. A large pool of retained*
15 *earnings in this environment would be beneficial in that the company balance*
16 *sheet potentially could sustain a series of annual losses, but balance sheet*
17 *retained earnings bear little relationship to the availability of cash resources."*
18

19 A further confusion amongst the Interveners is the idea that Manitoba Hydro's equity
20 represents customer contributions "*held in trust*" and for their benefit as there is no
21 "*shareholder per se*". Therefore, such contributions must be limited to the greatest
22 extent possible so as to minimize the opportunity cost to ratepayers of having their
23 funds tied up in the reserves or retained earnings of the Corporation. This is false.
24 Manitoba Hydro has an owner. It is the Province of Manitoba. Even in a "*cost-recovery*"
25 framework, any residual revenue collected in excess of costs accrues to the equity
26 holder. Manitoba Hydro gave considerable testimony during the direct evidence of its
27 Policy Panel (Transcript Pages 230 to 236) regarding the nature of the relationship
28 between Manitoba Hydro, its customers and the Province of Manitoba as shareholders.
29 The Province of Manitoba is the beneficiary of Manitoba Hydro's equity as its owner.
30 While it does not earn a return (or dividend) on such equity, it is still entitled to the
31 assurance of sufficient reserves to be retained in the utility to severely limit the risk of
32 being called upon to assist in the funding and support of the utility. Therefore, the duty
33 of the ratepayer is to fund such reserve contribution with no expectation of refund or
34 return.
35

1 Funding of net income through rates is the cost of providing for the buffer (i.e. net
2 income reserves) that must be maintained and added to proportionately as the
3 Corporation's asset base and debt grows so as to limit the likelihood of taxpayer funded
4 intervention at any point including one of financial distress. This is the "quid pro quo" of
5 Manitoba Hydro's relationship with the Province of Manitoba under which it is able to
6 obtain financing at highly preferential terms to that which the Corporation could on its
7 own and all for the benefit and account of the ratepayer. Absolute dollar levels of equity
8 comprised of historical retained earnings are irrelevant to the fiscal management of the
9 Corporation. It is the addition to equity reserves from regular and sufficient net income
10 that abates the absolute level of debt which is the essential driver of Manitoba Hydro's
11 financial risk.

12 13 **3.3 Ratepayer Benefits**

14 MPA's assertion on page 55 of Exhibit CC-17 that Manitoba Hydro's "equity is essentially
15 dead money. It earns no return, but nevertheless has been taken out of the hands of
16 ratepayers who could otherwise use it" is also erroneous. This stands in contrast to
17 MPA's evidence at NFAT as a PUB IEC wherein the response to CAC/MPA 1-012(d) they
18 stated:

19
20 *"If Manitoba Hydro has a larger balance sheet, then it would be better able to*
21 *absorb shorter term or less severe financial shocks, without the risk that it might*
22 *be perceived as being no longer financially self-supporting. A more robust*
23 *corporation could simply wait for fortunes to turn, rather than immediately*
24 *seeking financial relief through higher rates. In this sense, a larger balance sheet*
25 *can be understood as a ratepayer benefit."*

26
27 MPA later confirms in this hearing (Transcript Page 5115) that debt does have a cost and
28 insofar as retained earnings result in avoided debt, ratepayers benefit in the form of not
29 having to pay the cost of that avoided debt. In other words, while the ratepayer is duty
30 bound to contribute to net income (in normal water years) as a trade-off for the
31 Province of Manitoba providing access to low-cost capital and standing still on a rate of
32 return, there is still substantial ratepayer benefit. It comes in the form of future interest
33 savings which accrue to ratepayers at the Corporation's cost of debt. While in 2016/17

1 the Corporation's average cost of debt (used to capitalize interest) was 4.89%⁵ which is
2 a modest discount to the 5.0% "social discount rate" advocated by Morrison Park as a
3 ratepayer cost of capital, it is entirely plausible in a prospective rising interest rate
4 environment that the savings provided by having reduced debt will exceed this notional
5 concept of a social discount rate. Moreover, the true benefit to ratepayers (and the
6 broader Manitoba economy) of rate stability from lower debt levels is not captured
7 anywhere in this calculus but is certainly a tangible benefit to customers.

8
9 Mr. Colaiacovo asserts at Transcript Page 5129 with respect to reserves:

10
11 *"So yes. If the 7.9 percent method -- rate is going to build up larger reserves, then*
12 *you will be able to resist more of the types of events that require reserves, but*
13 *that doesn't necessarily mean it's a good idea to build up those reserves because*
14 *you have to look at what the probability of those events are going to be and your*
15 *actual requirement for those reserves before you decide to build them up."*

16
17 The purpose of building up financial strength through sufficient positive net income and
18 cash flow, as Manitoba Hydro is proposing, is to limit the growth of debt and abate it to
19 more sustainable levels relative to the size of its customer base and the inherent risks in
20 its business. The benefit is not only derived from higher resistance to possible or even
21 probable negative events. The benefit is the interest savings in and of itself and the
22 relative rate stability that ensues. In PUB/MH II-21b, pages 4-23, Manitoba Hydro
23 demonstrates how this benefit holds regardless of actualities that present in comparison
24 to forecast.

25
26 MPA produced an analysis which compares the present value to customers of two
27 alternate rate paths and concluded that at a "social discount rate" of above 4.93%, the
28 3.95% rate path is preferable at least by this measure (Exhibit CC-17, Pages 47 to 48).
29 This conclusion is unsupportable, given the fundamental misunderstandings of the role,
30 ownership and benefits of equity described above.

31
32 Manitoba Hydro demonstrated in its Rebuttal Evidence that, with the appropriate
33 Weighted Average Term to Maturity ("WATM"), 3.95% rate increases are required

⁵ see Note 7 on page 66 of Manitoba Hydro Electric Board 66th Annual Report for the year ended March 31, 2017, filed in the response to PUB MFR 13 Updated)

1 throughout the forecast period in order to restore the 25% equity ratio (Exhibit MH-52,
2 Appendix 1.6 and 1.7). On this basis, the “equalizing” discount rate of the two
3 compared rate paths climbs to 6.4%, well above the 5% MPA asserts as the appropriate
4 social discount rate. At a social discount rate below 6.4%, the rate path assumed in
5 PUB/MH II-21(b) produces present value benefits to ratepayers in addition to any
6 advantages to Manitoba economic development that may stem from the prospect of
7 lower, more stable rates sooner.

8
9 Manitoba Hydro has also noted that it is inappropriate to attribute the same discount
10 rate to two rate paths with a wholly different likelihood of occurring. MPA confirmed in
11 its response to MH/Coalition-(MPA) 20(a) that the 3.95% rate path has a higher
12 likelihood of unexpected/unplanned rate action. Using the same discount rate to
13 compare two scenarios with a different risk profile is inconsistent with financial theory.

14
15 The 3.95% rate scenario places increased risk on ratepayers. Even in the base case,
16 equity falls to a level of 10% and is maintained for years. The PUB has indicated in the
17 past its discomfort with 10% equity levels as noted on pages 2 and 23 of Order 43/13:

18
19 *“The Board is concerned with the projected future deterioration of Manitoba*
20 *Hydro's financial targets, in particular the debt-to-equity ratio that will fall from*
21 *a current level of 75:25 to 90:10 by 2021, even with projected annual rate*
22 *increases of approximately 4%, which is twice the projected level of inflation. This*
23 *deterioration will put Manitoba Hydro in a weaker financial position given its*
24 *planned capital spending over the next two decades.”*

25 ...

26 *“The Board is concerned that, by moving towards a 90:10 debt-to-equity ratio by*
27 *the end of the decade, there will be an insufficient retained earnings reserve to*
28 *deal with droughts and other risks such as infrastructure failure or rising interest*
29 *rates.”*

30
31 The PUB further noted the significance of maintaining capital adequacy to alleviate
32 pressure on the Province of Manitoba in PUB Order 101/04 page 29:

33
34 *“With a debt:equity ratio of 75:25 ratepayers would have increased assurance of*
35 *future rate stability. Increased retained earnings would provide for a*

1 continuation of advantageous interest rates and finance costs. It would also
2 provide increased confidence that a direct financial contribution to MH's capital
3 would not be sought from the Province."
4

5 **3.4 A 20-Year Financial Plan does not work**

6 In the face of a rapidly changing industry, significantly higher capital investment needs
7 and a deteriorated growth outlook, the 20 year path to addressing Manitoba Hydro's
8 financial condition by 2033/34 advocated at NFAT and in the 2015/16 & 2016/17
9 General Rate Application ("GRA") is imprudent and unworkable.
10

11 While unpleasant, the reality is that Manitoba Hydro does not appear poised to grow its
12 way into the significantly increased and unsustainable levels of debt it is incurring to
13 complete major capital projects, such as the Keeyask Generating Station and the Bipole
14 III Reliability Project. As such, earlier and more aggressive action than what was
15 contemplated in previous 20-year financial plans is required to address a debt load that,
16 left unchecked, could compromise rate stability and affordability for generations of
17 Manitoba Hydro electricity customers.
18

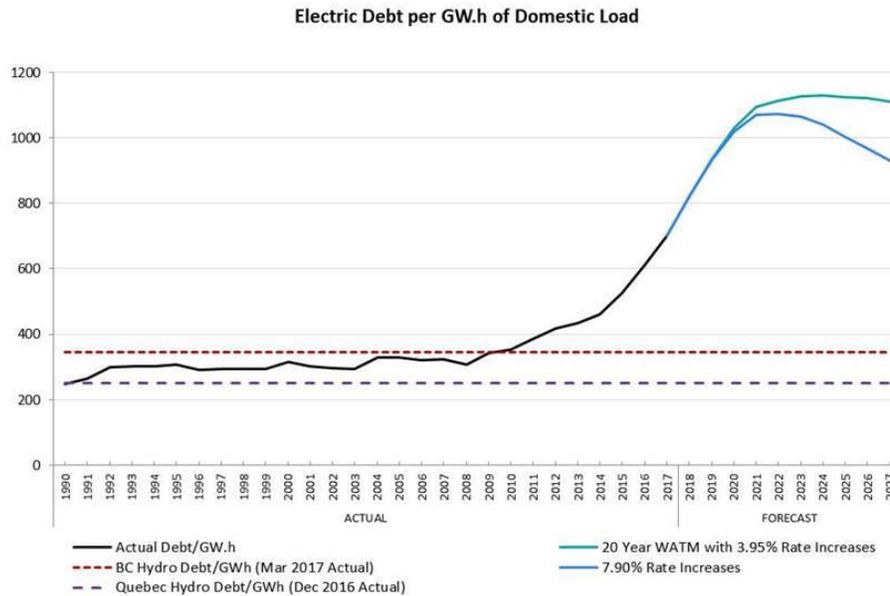
19 Taking almost two decades to address Manitoba Hydro's weak capitalization fails for a
20 number of reasons which are discussed in the sections that follow.
21

22 **3.4.1 Prolonged and unmitigated exposure to interest rate increases**

23 Section 3.2 above provides a discussion of the role of equity and net income in
24 maintaining Manitoba Hydro's financial stability. The issue with Manitoba Hydro is not
25 too little equity. The real issue is that too large a debt burden is being carried by a
26 stagnant customer base. **Figure 3.7** below demonstrates that absolute levels of debt
27 will grow to almost 4 times as indebted as Manitoba Hydro was immediately following
28 Limestone. This is clearly out of all historical proportion to the size of Manitoba Hydro's
29 business. Likewise, the debt burden on Manitoba Hydro's customers will be larger than
30 any previous plan brought in front of the PUB. Stronger action must be taken to address
31 this significant and unavoidable debt.
32
33

1

Figure 3.7



2

Source: Exhibit MH-52, Page 25

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Under the 3.95% rate path, net debt will grow to \$24.8 billion by the end of 2023/24 at which point the Keeyask Generating Station is fully in-service. Notwithstanding intervener conjecture (page 4-5 of Exhibit MIPUG-13) that Manitoba Hydro will be “rapidly” retiring debt, in fact net debt builds in the six years after Keeyask In-Service to \$25.1 billion at the end of 2026/27 under a 3.95% rate plan. It is of note that despite cumulative rate increases of almost 50% by the end of that period under the MH15 rate plan (3.95% until 2028/29) debt remains within roughly 5% of this peak level until 2033/34 - 16 years from now (Exhibit MH-52, Appendix 1.3). The failure to make any appreciable repayment of debt in the face of such cumulative rate increases demonstrates the inadequacy of the 3.95% plan.

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In financial terms, Manitoba Hydro has no greater risk than rising interest rates. Once Keeyask is in service, Manitoba Hydro will have annual interest expense of approximately \$1.25 billion per year, assuming its projection for both interest rates and the final capital needs of the major projects prove accurate. This compares to \$2.0 billion of domestic revenue in 2023/24 following the 3.95% rate path. In other words, Manitoba Hydro will be consuming 62.5% of every domestic revenue dollar paying interest expense (i.e. \$0.63 of every dollar, as shown on Slide 21 of Exhibit MH-64). On \$25 billion of debt, even a 1% increase in interest rates would have dire consequences.

1 Manitoba Hydro will see immediate and material increases in its revenue requirement
2 should interest rates begin a path back from historic low levels to long-term average
3 levels.

4
5 It has been of great benefit to Manitoba Hydro ratepayers to undertake such a
6 significant expansion program with the benefit of low interest rates. However, it would
7 be highly imprudent to not take action now to curb debt growth given the clear danger
8 and unaffordable consequences of unplanned interest rate escalation. The presumption
9 that interest rates will stay within sight of historic lows for more than the next decade is
10 too large a wager to expose ratepayers to. As seen on in the chart on page 10 of
11 Appendix 3.5 to the Application, interest rates have historically demonstrated the
12 capacity to increase and decrease significantly over 10 year time frames let alone 15 or
13 20 years.

14
15 The need to address the impact of lower forecast domestic load growth cannot be
16 overlooked. One way of considering debt load at the customer level is the amount of
17 debt per kWh of consumption. This is appropriate as the interest servicing of each
18 dollar of incremental debt load must be absorbed in customer rates which are
19 expressed in cents per kWh. At NFAT, when net debt crested at \$21.6 billion in 2022/23
20 (Exhibit MH-93, page 14), domestic load (at generation) was forecast at 26,567 GWh
21 (PUB/MIPUG 1, page 4). Net debt/GWh of domestic load (at generation) was therefore
22 forecast at \$813,000/GWh. Manitoba Hydro's current forecast sees only 25,175 GWh
23 of domestic load (at generation) in 2022/23 (PUB/MIPUG 1) which compares to forecast
24 net debt of \$24.8 billion (Appendix 1.3 to Exhibit MH-52). This translates to Debt/GWh
25 (at generation) of \$984,000. The consequence is that much greater debt is being
26 shouldered by much lower customer volumes. On a proportional basis to domestic load,
27 peak net debt per GWh will be almost 21% higher in 2022/23 under MH16 Update with
28 Interim (i.e. 7.9% rate path) as compared to NFAT.

29
30 MH16 Update with Interim, notwithstanding higher rate increases, is still reflective of
31 more financial risk than was contemplated at NFAT. The higher rate path assumed in
32 MH16 Update with Interim, beginning with the 7.9% rate increase effective April 1, 2018
33 requested by Manitoba Hydro in this GRA, is essential in order to abate debt growth to
34 levels more consistent with prior plans notwithstanding taking several years longer to
35 do so.

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3.4.2 Cannot Forecast Breakeven or Negative Income

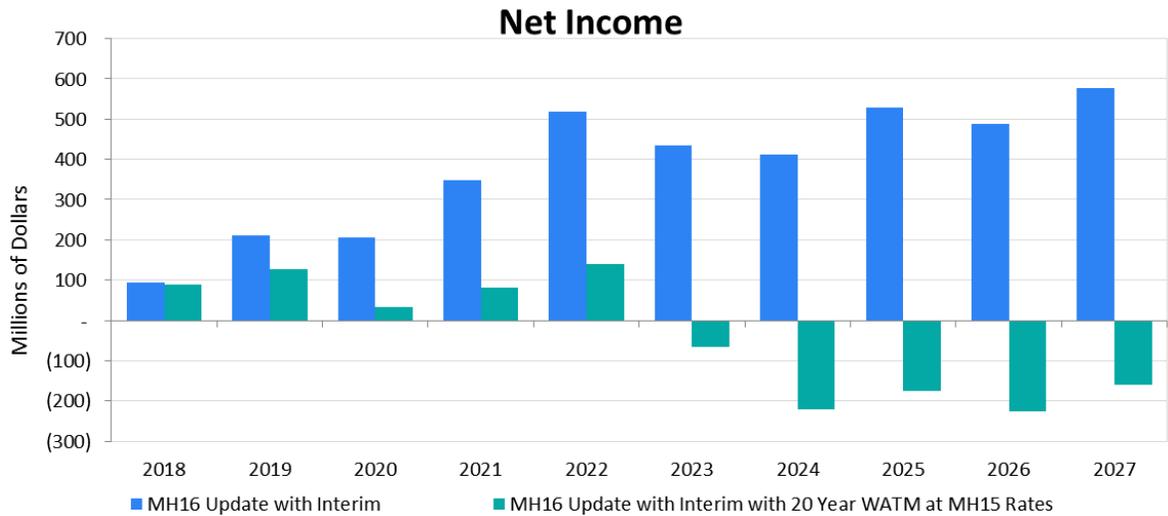
All of Manitoba Hydro’s integrated financial forecasts, including MH16 Update with Interim, are founded on the assumption of normal water conditions. Manitoba Hydro has been clear that it believes it is imprudent, as a planning matter, to pursue a rate strategy with a goal of negative net income in any one year let alone for a sustained period. It would appear that Mr. Colaiacovo from MPA agrees:

*“And if the rates are high enough, well, then, that helps guide you to a -- a decision that those rates are sufficient. Then, you would also ask yourself, if water was at more typical levels over that period, over that five (5) or seven (7) year period, what would be the effect? Would it be -- **would we be making progress on our financial targets more broadly? Would be -- we be repaying capital? Right?...** So, you know, you always want to make sure that in a challenging scenario, you have enough reserves, **but you also want to pay attention to what happens when water is at typical levels** and -- and -- and that -- that kind of an analysis, I think, would guide you to making a rate decision.”*
(Emphasis Added) (Transcript page 4941)

In the years following Keeyask ISD, implementation of the MH15 rate path results in: a) substantial, sustained net losses; b) significant deterioration in the equity ratio; and, c) increasing net debt levels.

1

Figure 3.8



2

3

Source: Exhibit MH-64, Slide 26

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5

Given Mr. Colaiacovo’s advice noted above, it is difficult to comprehend how he could endorse a plan that would see Manitoba Hydro losing in the range of \$200 million per year with Keeyask in service.

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Manitoba Hydro must have sufficient domestic revenue that is recovered from ratepayers such that it can expect to make meaningful, positive net income in normal water conditions. When the unforeseen arises, net income can flex downward to avoid the need for immediate borrowing or rate response. If the planned net income is achieved, this income can be contributed toward debt retirement. However, it is acknowledged by both MPA (transcript page 5114) and Mr. Bowman (Transcript Page 6382) that equity is not cash reserves and that in the absence of net income, Manitoba Hydro will have no choice but to raise rates or increase debt in the event of below forecast conditions let alone drought or sharply rising interest rates.

18

19

20

21

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23

The scale of targeted net income must take into account the scope of Manitoba Hydro’s activities. A decade ago, Manitoba Hydro earned net income in the order of \$250 million to \$350 million on net plant in service of approximately \$7.5 billion. (Exhibit MH-64, Slide 66). The PUB acknowledged the importance of net income relative to Manitoba Hydro’s scale when it wrote, in Order 143/04, on page 84:

24

1 *“While net income levels of \$50 million are significant in absolute dollar terms,*
2 *they are modest for a Corporation with the assets, debts, retained earnings and*
3 *responsibilities of MH. MH’s debt to equity ratio is below the Corporation’s target*
4 *and generally accepted industry standards.”*

5
6 At the time of that Order, Manitoba Hydro had net plant in service of approximately \$7
7 billion and net debt of approximately the same amount. When Keeyask comes into
8 service, Manitoba Hydro’s net plant in service will be roughly four times greater (\$27
9 billion) with debt, following the MH15 rate path, of \$25 billion. The MH15 rate path
10 produces a net loss in 2023/24 of \$222 million and continuing to follow this plan does
11 not lead to net income of greater than \$100 million before 2030/31.

12
13 In the same Order, at page 86, the PUB noted:

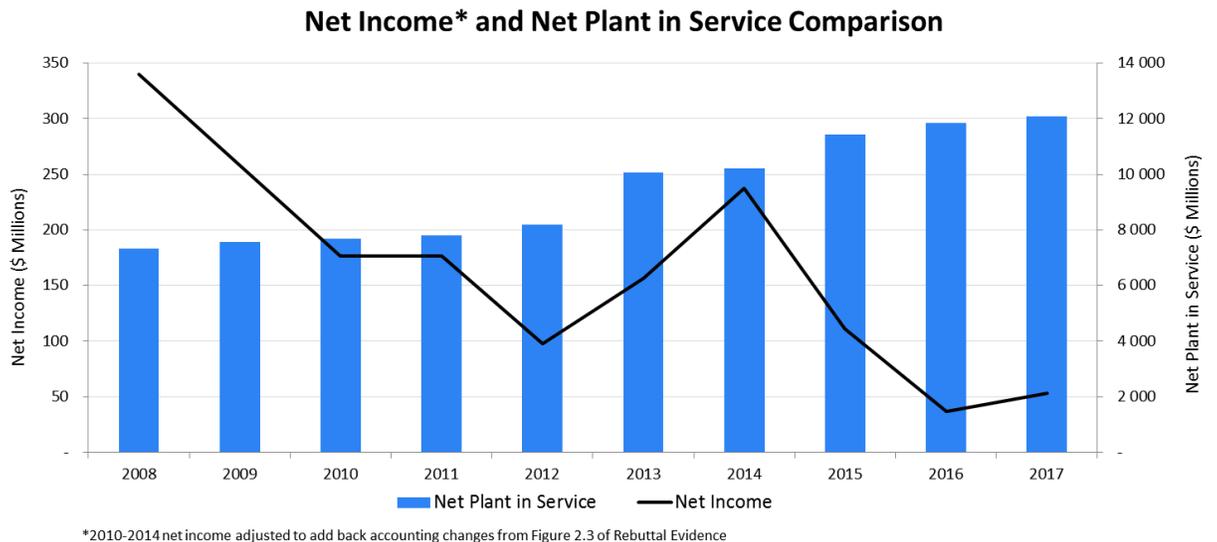
14
15 *“MH explained during the hearings that even in the absence of another drought*
16 *it would not reach its targeted debt to equity ratio by 2013/14, and provided no*
17 *plan to achieve its target within this 10-year planning horizon. The Board believes*
18 *that this situation is not reasonable.”*

19
20 Manitoba Hydro notes the PUB’s concern with both the debt to equity ratio and the 10
21 year path. Manitoba Hydro does not believe that the cause of the capital deficiency
22 (drought vs. a major period of expansion) impacts the requisite steps to address the
23 PUB’s well documented concerns in PUB Orders 101/04, 143/04 and 90/08 regarding
24 the risks of inadequate reserves and levels of debt. For example, in Order 90/08 page
25 18

26
27 *“It is not reasonable to assume that a Utility can expend over \$18 billion in new*
28 *capital expenditures without an up-front investment in its capital structure,*
29 *higher rate increases will provide that additional capital and reduce to some*
30 *extent the debt that MH will have to take on to complete these projects. Debt*
31 *comes with costs, interest and annual principle payments, and, as well, is*
32 *associated the risk of future increases in interest rates. The Corporation’s risks*
33 *rise as its export opportunities, investments and debts increase. In the Board’s*
34 *view, this warrants a larger rate increase.”*

1 Accepting a path of rate increases that are insufficient to generate positive net income
 2 would be a concerning continuation of a trend wherein net income (and therefore,
 3 reserve contribution and balance sheet management) have been systemically eroded
 4 while the assets and debts of the business continued to expand as demonstrated in
 5 **Figure 3.9** below. It should be noted as well that this erosion occurred notwithstanding
 6 above average water conditions in every year since 2004/05 and sharply declining
 7 interest rates throughout the period.

8
 9 **Figure 3.9**



10
 11 **Source: Exhibit MH-64, Slide 66**

12
 13 When normalized for water conditions and other unusual items, Manitoba Hydro has
 14 already been in a loss-making position for several years as discussed in detail in Section
 15 2.1.2.

16
 17 Net income is an essential feature of prudent financial planning for a business of the
 18 scale, complexity, importance and volatility of Manitoba Hydro. The PUB recognized
 19 this in Order 90/08, on page 7 when it wrote:

20
 21 *“It is prudent that known risks are addressed now, in part through the provision of*
 22 *additional revenue, so as to best ensure adequate financial reserves ahead of*
 23 *uncertain times.”*

1 **3.4.3 Prudent Financial Plans Do Not Depend on the Back-End of a Twenty Year**
2 **Financial Forecast Proving Accurate**

3 Forecasting is inherently unreliable. Manitoba Hydro believes limited value should be
4 ascribed to forecasts a decade or more in the future as the potential for volatility in key
5 assumptions, many of which are beyond Manitoba Hydro’s ability to control, reduces
6 the second half of a twenty year forecast to little more than a hypothetical modeling
7 exercise. The further out the forecast goes, the less likely it is to be accurate. As noted
8 by Mr. Shepherd:

9
10 *“A decade is a long time. In any business I've been around, forecasting ten (10)*
11 *years in the future, let alone fifteen (15) or twenty (20), is very difficult, perhaps*
12 *nearly impossible. So a plan that has you walking down a tightrope of essentially*
13 *no net income until the early 2030s is begging for trouble, especially when your*
14 *outlook for growth is as weak as ours has become. So in taking up to twenty (20)*
15 *years to deal with a serious problem, you're choosing to take insufficient action*
16 *upfront, action that is required to be in the position where you have some*
17 *flexibility to make different choices as the future unfolds.*

18
19 *Our previous plans relied to -- to far too great an extent on nothing adverse*
20 *happening over a very long period of time. That's relying on hope. **Put another***
21 ***way, your financial strategy is to stay lucky for a very long time.**”* (Emphasis
22 Added) (Transcript Page 163)

23
24 Consider the response to PUB/MH II-41 wherein the range of net income outcomes on
25 918 model runs is charted under the MH16 Update with Interim at MH15 Rate Increases
26 scenario. By 2027, the financial model under average of all 102 water flow conditions
27 shows a net loss of \$160 million; however, that level of net income is below the mid-
28 point of a range from a \$500 million net loss to \$230 million in net income. In other
29 words, with all the variables and assumptions that go into a financial forecast, actually
30 achieving a forecast level of net income 10-20 years from now will be as much a matter
31 of happenstance and luck as prescient forecasting. Therefore, Manitoba Hydro is of the
32 view that assuming achievement of a plan over such a long horizon is not a prudent
33 course of action.

1 Ratepayers should also take no confidence in such a plan. Businesses looking to invest
2 or expand in Manitoba will be well aware that Manitoba Hydro's interest expense alone
3 will be unpredictable and uncontrollable given the roughly \$20 billion in new borrowing
4 and refinancing Manitoba Hydro must execute in the next 10 years (Appendix 3.5 of the
5 Application). They will see that interest expense of \$1.251 billion (Appendix 1.3 of
6 Exhibit MH-52), in a normal water year and once Keeyask is in service, will represent
7 40% of Manitoba Hydro's cost structure, 44% of its total revenue and 60% of its
8 domestic revenues. The latter metric will be deeply concerning knowing that Manitoba
9 Hydro has no ability to increase its export pricing and therefore the domestic customer
10 will bear all of the volatility in interest rates. While a lengthy pattern of 3.95% rate
11 increases may, when presented in a spreadsheet, appear steady and predictable,
12 businesses will understand that more debt will foster more risk to rates. The 3.95% rate
13 path (or any derivative thereof) will rightly be thought of as academic and an aberration.
14 While conceptually interesting, it has a very low possibility of actually occurring.

15
16 Nonetheless, as demonstrated in the response to Coalition /MH II-19, the 20 year/3.95%
17 plans make inconsequential progress toward the Corporation's financial goals in the first
18 decade notwithstanding assumptions of significant rate growth, sustained low interest
19 rates, appreciating export prices, normal water conditions and no further deterioration
20 in capital costs. MH16 Update with Interim at MH15 Rates (Appendix 1.3 to Rebuttal
21 Evidence) is indicative. Debt does not actually peak until the 10th year of 2026/27 which
22 is well after the Keeyask in-service date of August 2021. The equity ratio deteriorates
23 steadily and unabated. The EBITDA to Interest target, which Manitoba Hydro notes is
24 favored by MPA, never comes close to being met. In the five years following the in-
25 service of Keeyask, Manitoba Hydro actually loses close to \$1 billion, increases its debt,
26 sees its equity ratio drop to 10% and moves further away rather than closer to its
27 financial goals.

28
29 It should not escape notice that Mr. Bowman's preferred 3.57% plan is based on the
30 achievement of the 25% equity ratio by 2035/36. This is two years subsequent to the
31 initial 2033/34 year time frame established at NFAT and repeated in IFF14 that was
32 reviewed as part of the 2015 GRA. As well, Mr. Harper proposes continuing the 3.95%
33 path for "*a few more years*" (five are actually required) in order to achieve the 25%
34 target in 2035/36. MPA also acknowledges the 3.95% path needs to continue for longer
35 time frames than forecast under NFAT, IFF14 or IFF15. The pattern should be clear. At

1 each rate application brought to the PUB for review, the advice will be to start working
2 toward achievement of its financial targets anew with another 20 year plan.

3
4 In addition to taking yet another two years, Mr. Bowman's preferred plan is also
5 characterized by requiring \$793 million of net income in its penultimate year (2034/35)
6 followed by \$883 million in its final year (2035/36) as two more years of 3.57% rate
7 increases are compounded on the 81% cumulative increases of the next 17 years
8 (Exhibit MH-93). This level of annual net income is respectively 62% and 59% higher
9 than under the Manitoba Hydro plan for 2025/26 and 2026/27 as it likewise completes
10 the restoration of its fiscal health and reaches 25% equity. See Section 3.4.5 for a
11 discussion of intergenerational equity paradoxes of Mr. Bowman's preferred plan.
12 Nonetheless, on this path endorsed by Mr. Bowman, the regulator would be accepting
13 that Manitoba Hydro would defer positive net income post-Keeyask until 2028/29. If
14 the regulator were prepared to accept that level of financial weakness for that length of
15 time, in Manitoba Hydro's view, it seems unlikely that the regulator would support the
16 kind of rate increases and net income projected from 2030 onward in Mr. Bowman's
17 preferred plan.

18
19 The end game is clear. The kinds of forecast errors that can befall such a razor-thin
20 financial plan are not imaginary or implausible. Each of the major risks – rising interest
21 rates, soft export prices, low water conditions or drought and capital overruns – have all
22 happened before. Manitoba Hydro arguably bears more financial risk than any other
23 Canadian hydro-based utility given its relative exposure to interest rate increases,
24 hydrology and export prices. A willingness to tolerate such a plan signals a bias to not
25 act proactively but rather wait until a crisis inevitably presents. It is ironic that the same
26 parties who have for many years criticized Manitoba Hydro's forecasting abilities are
27 now effectively encouraging the PUB to attribute a high degree of confidence in the
28 back end of a twenty year forecast.

29 30 **3.4.4 Capital markets are growing more concerned**

31 The principal benefit of dealing with Manitoba Hydro's unsustainable debt is the payoff
32 of lower, more stable electricity rates in the long run. There is no plausible future
33 scenario wherein lower debt levels do not return lower rates to Manitoba Hydro's
34 customers. PUB/MH II-21 provides some illustrative examples to demonstrate this
35 benefit. A corollary benefit of addressing absolute debt levels which are now set to grow

1 beyond any previous forecast level is the continued support and confidence of capital
2 markets participants which is vital to the Province of Manitoba and Manitoba Hydro's
3 borrowing programs and interest costs.

4
5 Credit rating agencies are a reasonable proxy for the types of analysis debt investors
6 undertake and the opinions they form. Any impartial review of recent credit rating
7 agency reports demonstrates clear and urgent signaling that markets are concerned
8 with the continued deterioration of Manitoba Hydro's financial profile.

9
10 **3.4.5 Intergenerational Equity argument is flawed and hypocritical**

11 The 19 year plan advocated by Mr. Bowman sees Manitoba Hydro building to \$25 billion
12 in debt post-Keeyask only to decline to below \$24 billion in the 2032/33 fiscal year,
13 which is over 15 years from today. The exposure to interest rate increases over that
14 timeframe is immense. Even by 2032/33, at which time this plan would result in having
15 implemented 75% cumulative increases while still not having increased equity beyond
16 17%, net debt will be more than 8 times domestic revenue (Exhibit MH-52, Appendix
17 1.3, Pages 2 and 4). Interest expense of \$1.24 billion will be consuming 40% of domestic
18 revenues even having increased rates cumulatively by 75% by that point. The argument
19 in favour of this is "*intergenerational equity*". In general terms, the theory is that it is
20 unfair for current ratepayers (and those of the next 10 years) to be unduly contributing
21 to the carrying costs of constructing the major new assets. Mr. Bowman's argument is
22 paradoxical in that the consequence of not having today's ratepayer make any
23 contribution to the continued erosion of the Corporation's balance sheet is exacerbated
24 risk and cost to the next generation. To do so in the name of intergenerational fairness
25 is disingenuous.

26
27 It is further hypocritical when the patterns of costs borne by ratepayers in each of the
28 first decade (2018-2027) and the second decade (2028-2036) are compared (see Figure
29 below):

1

Figure 3.10

	MH Plan 2018-2027	Bowman 3.57% Plan 2018-2027	Bowman 3.57% Plan 2028-2036
Cumulative Net Income	\$3.8 billion (over 10 years)	\$0.2 billion (over 10 years)	\$3.7 billion (over 9 years)
Net Debt post Keeyask	\$2.4 billion decrease (2023-27)	\$0.3 billion increase (2023-27)	\$3.6 billion decrease (9 years 2028-36)
Net Income in year target is achieved	\$577 million (2027)	Equity ratio and EBITDA/Interest targets not achieved	\$883 million (2036)
Cumulative Rate Increase	77.4% (to 2027)	41.7% (to 2027)	94.3% (to 2036)

2

3

Source: Manitoba Hydro Plan Appendix 3.8 and Mr. Bowman 3.57% Plan Exhibit MH-93

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As can be seen from **Figure 3.10** above, notwithstanding 42% cumulative rate increases, Mr. Bowman’s proposed plan makes no contribution to progress on financial targets or debt reduction, in fact the opposite. Debt increases during the period post-Keeyask while the equity ratio declines from 14% to 12% due to sustained net losses. Mr. Bowman’s plan only produces positive, albeit immaterial, net income in aggregate in its first 10 years due to the impact of arbitrary accounting choices and the assumption of an ill-advised debt terming strategy. Even so, the plan produces \$405 million of cumulative losses from 2022/23 to 2026/27.

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Further, the profile of net income and debt reduction borne by the first decade’s ratepayers under the Manitoba Hydro Plan (MH16 Update with Interim) is exactly the same as or better than the profile of net income and costs borne by the ratepayers in the second decade (in fact even further condensed into 9 years from 10) under Mr. Bowman’s 3.57% plan. In other words, Mr. Bowman is proposing to take essentially the same pattern of reserve contribution and cash contribution Manitoba Hydro is proposing to be shouldered over the next 10 years and instead bestowing it on the ratepayers of the following 9 years and doing so in the name of intergenerational equity. In fact, there is no sharing or spreading of the costs of restoring Manitoba Hydro’s financial health due to the simple fact that Manitoba Hydro’s financial health not only does not improve in the first 10 years of Mr. Bowman’s plan, it deteriorates. Mr. Bowman is simply making a choice of which generation to park the responsibility on. The next generation has the added burden of now paying rates 94% higher than today

1 (and only if things have gone to “plan” for more than a decade) and having done little to
2 nothing before the early 2030’s to reduce the rate volatility inherent in leaving debt
3 unchecked.
4

5 **3.5 Changing assumptions in the Financial Model in order to defer the need for rate 6 increases is not prudent**

7 The PUB has heard argument in favor of numerous alternate (and lower) trajectories
8 supported by questionable assumptions inserted into a forecast scenario with the sole
9 objective of providing support for deferring the rate action now required. A financial
10 forecast is a compilation of hundreds of assumptions all of which can be modestly
11 changed to engineer any outcome a party desires. Manitoba Hydro has put forward in
12 MH16 Update with Interim its best effort at a baseline forecast from which to make
13 longer term rate planning decisions. As the PUB has made clear, at issue is effectively
14 one rate increase, the request for 7.9% to take effect on April 1, 2018. The actual path
15 of future rate increase requests will be a function of updated assumptions and events
16 between now and Manitoba Hydro’s subsequent rate application(s).
17

18 However, it would be imprudent to make today’s rate decision – in the context of
19 important signaling on longer term financial goals the PUB wishes to support – based on
20 overly optimistic assumptions particularly in matters well beyond Manitoba Hydro’s or
21 the PUB’s ability to control. For example:
22

23 **3.5.1 Assumption of Capacity Values for Uncommitted Firm Energy.**

24 The proposition that there is capacity value recognized in the marketplace is not
25 something Manitoba Hydro takes issue with. However, to build a financial plan
26 incorporating such values in the absence of a contracted counterparty adds unnecessary
27 risk to the financial plan. Manitoba Hydro has given evidence (PUB/MH I-50) that the
28 likelihood of engaging a counterparty in the next 5 years is extremely low owing to the
29 planning horizons of these kind of bilateral agreements. Daymark endorsed this view as
30 follows:
31

32 *“MS. MARLA BOYD: And I understood your evidence to be that that wouldn't be a*
33 *significant source of revenue until -- at least for the next five (5) years, and*
34 *perhaps 2025?*

1 MR. DANIEL PEACO: We did not find a lot of evidence in -- in either individual
2 counterparties or the MISO market generally being short of capacity until that
3 time, right." (Transcript Pages 4280 to 4281)
4

5 Beyond 5 years, it must be recognized that simply having the firm energy available
6 provides no assurance of entering into a contractual agreement. Further, Manitoba
7 Hydro's uncommitted firm energy is a depleting resource particularly beyond the 10
8 year forecast horizon when Manitoba load growth starts absorbing excess supply.
9

10 **3.5.2 Change regulatory accounting policy to increase income in the near term.**

11 The frenzied debate over depreciation methodologies has obscured the fact that the
12 transition to IFRS has substantially reduced annual depreciation expense (even under
13 IFRS ELG) due to the removal of negative net salvage value. Nonetheless, as noted in
14 Exhibit MH-93, the proposed changes by Mr. Bowman, including 12 year debt, indefinite
15 capitalization of ineligible overheads amortized over 30 years and ELG/ASL depreciation
16 methodology differences not amortized at all, make an immaterial (0.15%) difference to
17 the annual rate path and no difference whatsoever to the critical debt and cash flow
18 issues facing Manitoba Hydro. Mr. Harper acknowledged the impact would be minimal
19 in the test years:
20

21 MS. PATTI RAMAGE: Okay, fair enough. You'd agree that if the Board adopted
22 these recommendations, it would have minimum impact on the requested rate
23 increases in this proceeding?

24 MR. WILLIAM HARPER: Yes, in terms of the two -- of the two -- of the two (2)
25 specific years we're looking at, yes.

26 (Transcript Page 5359)
27

28 Further commentary regarding Manitoba Hydro's proposed treatment of existing
29 Regulatory deferral accounts can be found in Section 17.
30

31 **3.5.3 Assume 12 Year WATM.**

32 Mr. Bowman opined that Manitoba Hydro's actions regarding reducing the WATM of
33 Debt are sensible and appropriate (Exhibit MIPUG-13, page 5-11) but took issue with
34 Manitoba Hydro's position that this strategy is only prudent under Manitoba Hydro's

1 7.9% financial plan and instead argued a 12 year WATM is an appropriate debt
2 management strategy when coupled with 3.95% rate increases.

3
4 Manitoba Hydro notes that Mr. Bowman acknowledges having no experience in capital
5 markets (Transcript Page 6202) nor does his CV indicate treasury management
6 experience. His willingness to place over \$9 billion of refinancing risk into the 2023 –
7 2027 timeframe in the absence of any prospective cash flow to manage the risk is
8 cavalier and indicative of an ongoing desire to maintain artificially low rates in the near
9 term, regardless of the risk it may impose on future ratepayers.

10 11 **3.5.4 Curtail DSM spending assumptions.**

12 The Efficiency Manitoba Act has been enacted in order to establish Efficiency Manitoba,
13 a new Crown Corporation charged with pursuing long range electricity savings targets
14 that are meaningfully in excess of the projected savings in Manitoba Hydro's integrated
15 financial forecast. The Efficiency Manitoba Act mandates cumulative 22.5 % energy
16 savings over 15 years, a figure well in excess of Manitoba Hydro's current plan of 17.3%
17 over 15 years.

18
19 Mr. Bowman's argument that Manitoba Hydro should assume lower DSM investment
20 and projected savings, as a path to lower rate increases, on the basis that *"it is*
21 *appropriate to consider that Efficiency Manitoba, its Minister, or the PUB will make a*
22 *finding that continuing large scale DSM is not cost effective for at least the next 5-7 or so*
23 *years"* (Pre-Filed Testimony of Patrick Bowman, Exhibit MIPUG-13, Page 6-25) is in the
24 face of mandatory legislation to the contrary is untenable and self-serving. In reality, it
25 is entirely plausible that once Efficiency Manitoba is formed and operational, that its
26 plans may require more investment and create greater load loss. Against that backdrop,
27 to assume significant savings on programming that is transitioning from Manitoba
28 Hydro's control (but not financial responsibility as a means to support lower rate
29 increases) is imprudent. For additional information regarding Manitoba Hydro's
30 Demand Side Management program and Efficiency Manitoba see Section 8.2.7.

31 32 **3.5.5 Curtail government payments.**

33 A number of Intervenor's have suggested the PUB recommend the Province of Manitoba
34 forego certain payments currently required be made by Manitoba Hydro to the
35 Province. To be clear, absent a signal from the Province of Manitoba of a willingness to

1 accommodate lower water rental, debt guarantee fees or capital tax payments from
2 Manitoba Hydro, it would be irresponsible to factor such an assumption into any
3 forecast underpinning a rate decision.
4

5 **3.6 MH15 Rate Plan Fails**

6 MPA concludes at page 34 of their report that, “...the 3.95% rate path is reasonably
7 robust from a cash flow perspective” by relying on the modeling results of the EBITDA
8 interest coverage ratio. MPA reaches this conclusion despite shortcomings of the
9 EBITDA to interest coverage metric identified at page 9 of Exhibit CC-17:
10

11 *“This measure alone does not clarify whether the company’s debt is increasing,*
12 *since there is no information captured in this metric about the size of capital*
13 *expenditures (if capital expenditures are greater than 0.8x Net Finance expense,*
14 *then Manitoba Hydro will have to borrow additional funds, but if capital*
15 *expenditures are less than 0.8x Net Finance Expense, then the corporation could*
16 *actually retire some debt principal). By the same token, this ratio provides no*
17 *information on whether the Debt : Equity Ratio is rising or falling.” (Emphasis*
18 *Added)*
19

20 Manitoba Hydro annually funds \$500 to \$600 million a year in Business Operations
21 Capital to continue to maintain and increase the capacity of the current system to meet
22 customers’ needs and to support its revenue projection. Additionally, Manitoba Hydro
23 must fund other costs like mitigation and other liability payments that do not flow
24 directly through the income statement and, therefore, EBITDA. In the very short term,
25 Manitoba Hydro may defer some costs to future periods but at the end of the day these
26 expenditures are not discretionary. Manitoba Hydro cannot defer system maintenance
27 and replacement indefinitely or the Corporation will not be able to meet the service and
28 reliability expectations of its customers. When system failure rates rise, Manitoba
29 Hydro is unable to maximize all the revenue it is able to generate and puts downward
30 pressure on the sufficiency of future revenues. Further, costs are deferred to periods
31 when replacement is generally more expensive. As a result, EBITDA to interest does not
32 provide a complete picture because it does consider whether the Corporation has
33 enough cash to continue to run its operation, and therefore, it does not inform as to
34 whether debt is going up or going down.
35

Regardless of the EBITDA to interest coverage metric limitations, the following table reproduced from Exhibit MH-64 shows that the ratio under the MH16 Interim with Update and MH15 Rate Increases scenario is well below the target of 1.80 times even before considering required investments in Business Operations Capital.

Figure 3.11

Financial Ratios:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Equity Ratio (Target > 25%)										
MH16 Update with Interim	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
MH15 Rates	15%	14%	13%	13%	13%	12%	12%	11%	10%	10%
Capital Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.40 x	1.48 x	1.47 x	1.88 x	2.34 x	2.25 x	2.37 x	2.34 x	2.20 x	2.29 x
MH15 Rates	1.39 x	1.33 x	1.15 x	1.36 x	1.59 x	1.30 x	1.21 x	1.20 x	1.10 x	1.18 x
EBITDA Interest Coverage Ratio (Target > 1.80x)										
MH16 Update with Interim	1.54 x	1.71 x	1.72 x	1.84 x	2.01 x	2.03 x	2.08 x	2.22 x	2.24 x	2.36 x
MH15 Rates	1.53 x	1.61 x	1.54 x	1.58 x	1.64 x	1.54 x	1.47 x	1.52 x	1.49 x	1.54 x
Other Metrics:										
EBIT Interest Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.10 x	1.21 x	1.20 x	1.31 x	1.45 x	1.38 x	1.36 x	1.47 x	1.45 x	1.54 x
MH15 Rates	1.10 x	1.13 x	1.03 x	1.07 x	1.12 x	0.95 x	0.83 x	0.86 x	0.82 x	0.88 x
Net Debt										
MH16 Update with Interim	\$ 18 473	\$ 20 743	\$ 22 407	\$ 23 296	\$ 23 609	\$ 23 388	\$ 22 831	\$ 22 201	\$ 21 613	\$ 20 947
MH15 Rates	\$ 18 474	\$ 20 825	\$ 22 657	\$ 23 809	\$ 24 496	\$ 24 761	\$ 24 811	\$ 24 877	\$ 24 994	\$ 25 060

Source: Exhibit MH-64, Slide 53

The table above also depicts Manitoba Hydro's former target ratio EBIT to interest coverage. Mr. Bowman points to this ratio as a critical test of rates sufficiency. The table shows that the 3.95% rate path that Mr. Bowman argues is adequate, grossly fails his own preferred test.

When the EBITDA to interest calculation is adjusted to incorporate Business Operations Capital and other non-discretionary cash needs as in the following table reproduced from Exhibit MH-64, the ratio of EBITDA to ongoing cash burdens is consistently below 1.0 times in all 10 years of the forecast period indicating that revenues are insufficient to fund interest and capital expenditures and the deficient portion must be borrowed. These tables demonstrate unequivocally that the 3.95 percent rate plan simply does not work.

1

Figure 3.12

(In Millions of Dollars)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
MH16 Update with Interim:										
EBITDA (Numerator)	1439	1676	1795	2068	2307	2308	2384	2495	2435	2508
Interest	936	982	1041	1121	1145	1138	1148	1125	1089	1060
Capital and Other Cash Needs	763	772	740	769	766	742	723	783	799	822
Cash Burdens (Denominator)	1700	1754	1782	1890	1911	1880	1871	1908	1888	1882
EBITDA / Ongoing Cash Burdens Equity Ratio	0.85 x 15%	0.96 x 14%	1.01 x 14%	1.09 x 15%	1.21 x 17%	1.23 x 17%	1.27 x 19%	1.31 x 21%	1.29 x 23%	1.33 x 25%
At MH15 Rates:										
EBITDA / Ongoing Cash Burdens Equity Ratio	0.85 x 15%	0.91 x 14%	0.91 x 13%	0.95 x 13%	1.01 x 13%	0.96 x 12%	0.94 x 12%	0.94 x 11%	0.92 x 10%	0.95 x 10%

2

3

Source: Exhibit MH-64, Slide 54

1 **4 THE FINANCIAL OUTLOOK HAS DETERIORATED SIGNIFICANTLY**

2 Intervener experts have asserted that there has been no deterioration in Manitoba
3 Hydro’s business such that the evidence advanced by the Corporation does not support
4 the 7.9% rate increase trajectory included in Manitoba Hydro’s current financial
5 forecast. This is a significant assertion to Interveners as it is the fundamental
6 underpinning of the belief that the 3.95% rate path put forward at NFAT and in the 2015
7 GRA (IFF14) remains viable (Section 5.0 of the Pre-Filed Testimony of Patrick Bowman,
8 filed on behalf of the Manitoba Industrial Power Users Group, Exhibit MIPUG-13 and
9 Section 3 of William Harper, Econalysis Consulting Services Evidence, filed on behalf of
10 the Consumers Coalition, Exhibit CC-20).

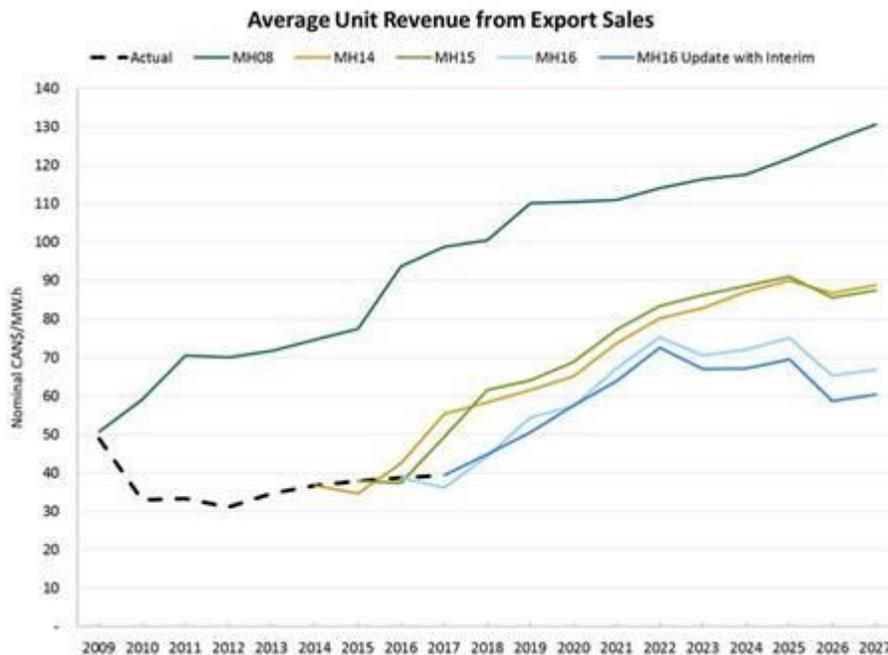
11
12 Manitoba Hydro submits that the conclusions advanced by such experts do not consider
13 all of the facts that are underpinning Manitoba Hydro’s current outlook and which are
14 summarized below:

15
16 **4.1 Export Revenues Are Materially Lower**

17 Since IFF14, the Corporation’s outlook for opportunity export prices, which is based on
18 third party forecasters, has decreased significantly (see chart below drawn from slide 39
19 from Manitoba Hydro’s Policy Panel Presentation, Exhibit MH-64). As shown in the
20 updated Schedule 10 provided in response to MH/Coalition (Harper)–5, forecast export
21 revenues in the 2018-2027 period have declined from \$8.0 billion under MH14 to \$6.4
22 billion under MH16 Update with Interim meaning \$1.6 billion of revenue has evaporated
23 from Manitoba Hydro’s expectations over the next 10 years.

1

Figure 4.1



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Source: Exhibit MH-64, Slide 39

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4.2 Domestic Load Growth and Revenues are Materially Lower

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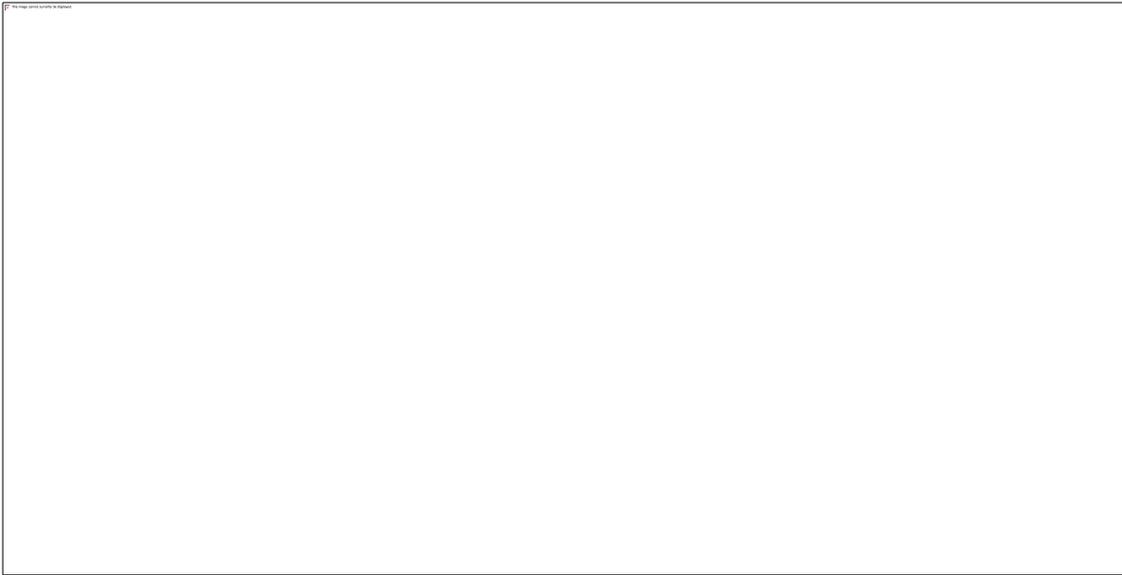
12

13

Manitoba Hydro’s outlook for domestic load growth has also declined sharply as seen in the figure below (reproduced from slide 38 of Exhibit MH-64). As shown in the updated Schedule 10 provided in response to MH/Coalition (Harper) – 5, forecast domestic revenues in the 2018-2027 period have declined from \$20.6 billion under MH14 to \$19.3 billion under MH16 Update with Interim (at MH15 rates) meaning \$1.3 billion of revenue has eroded from Manitoba Hydro’s expectations over the next 10 years.

1

Figure 4.2



2

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Source: Exhibit MH-64, Slide 38

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4.3 Debt Has Gone Up

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Since MH14 and MH15, the capital costs for the major projects currently underway have increased significantly. The Bipole III reliability project budget has increased from \$4.6 billion to \$5.0 billion while the Keeyask Generating Station budget has increased from \$6.5 billion to \$8.7 billion. These two projects combined represent a 23% increase in capital costs in MH16 Update with Interim as compared to prior forecasts which, in turn, significantly increases the revenue requirement in the updated forecast.

Since NFAT, Manitoba Hydro's outlook for peak net debt level has climbed by over 15% or \$3.4 billion dollars (Manitoba Hydro Follow-up to Undertakings 7 & 8, Exhibit MH-93, Page 14).

Combined with the above noted deterioration in load growth since 2014, the debt load on customers is rising to more than four times the relative debt levels after Limestone went into service as demonstrated at Figure 1.16 of Manitoba Hydro's Written Rebuttal Evidence (Exhibit MH-52). As explained by Mr. McCallum in his direct evidence (Transcript Page 134):

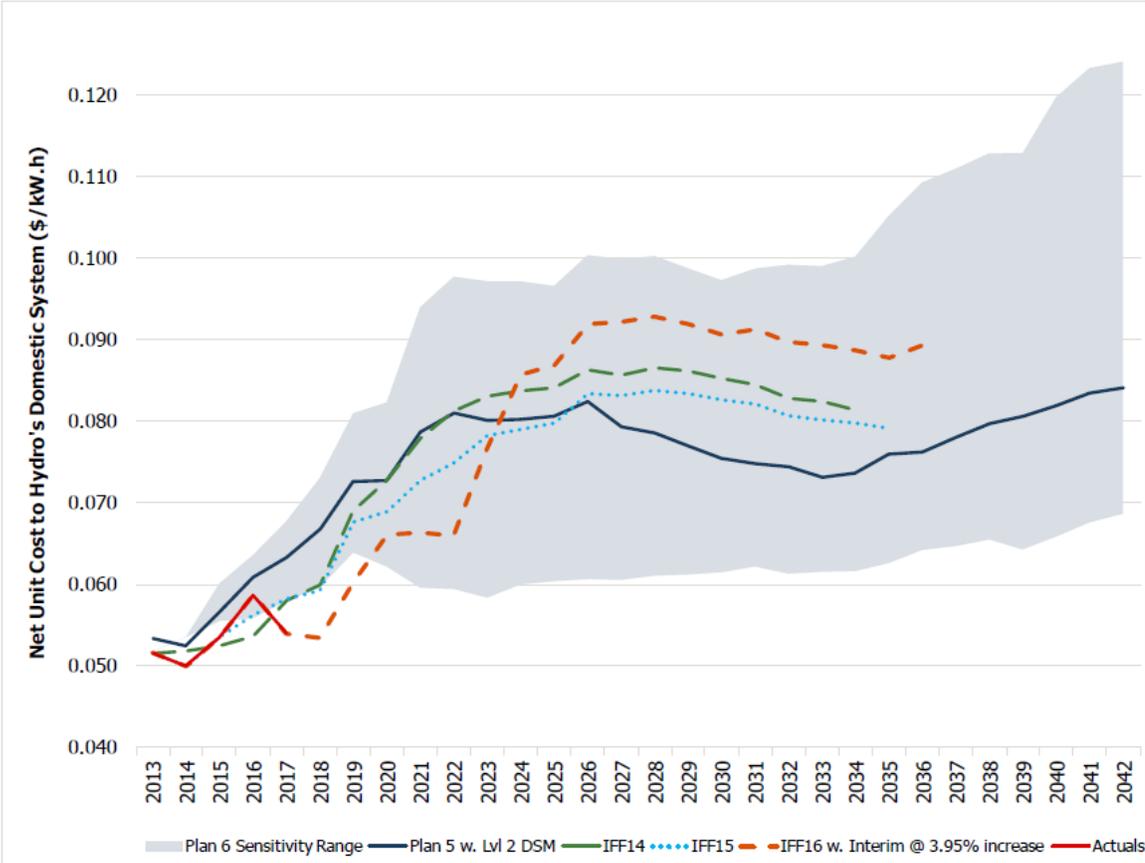
"The debt we will inescapably build over the next several years is, simply put, unsustainable. The only -- the old way of thinking about how to fix Manitoba

Hydro's finances, and how long to take to do it will simply not work. The old plans have clearly already failed. We cannot put this off any longer. Action to address today's immediate situation is required if we are to protect all stakeholders' long term best interests".

In PUB/MIPUG-1, Mr. Bowman provides a corrected chart (reproduced below) comparing net unit costs under NFAT Plan 5, IFF14, IFF15 and IFF16 Update with Interim (at MH15 Rates). While Manitoba Hydro takes issue with these calculations being done with an "at generation" domestic load, as seen in the chart below, under MH16 Update with Interim, net unit costs are now forecast to be significantly higher than under any of the prior forecasts.

Figure 4.3

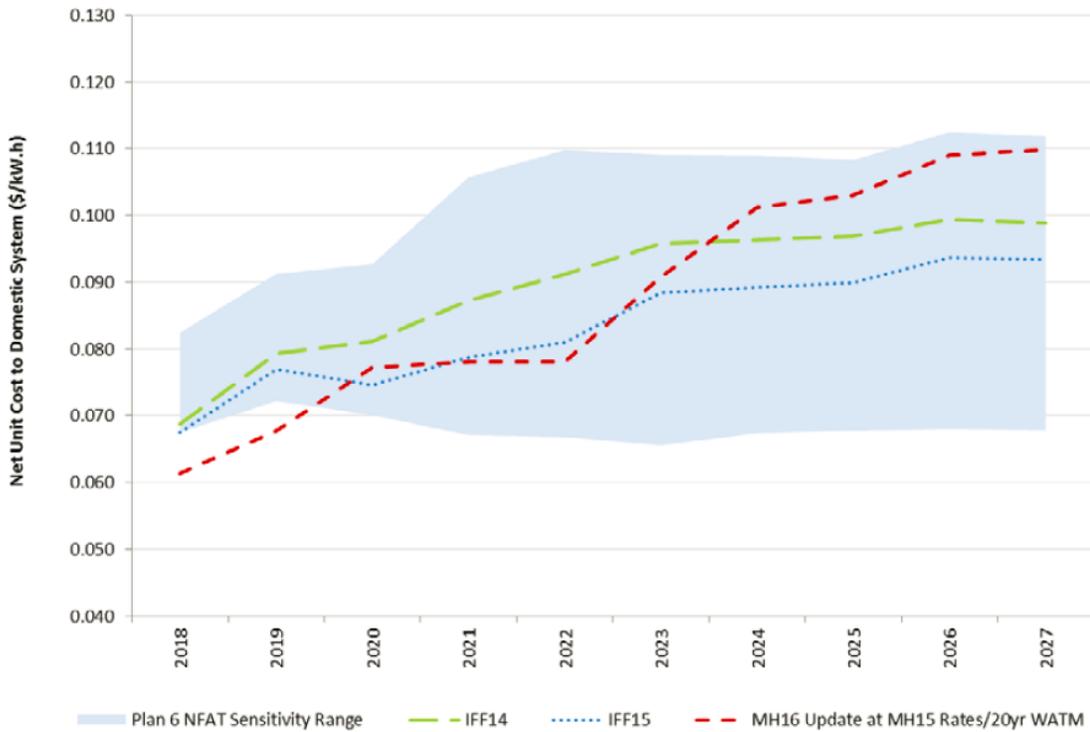
Figure 5-1: Net Unit Cost of Hydro's Domestic System (before reserves) Under NFAT Plan 5/6 versus IFF16 (assuming 3.95% increase scenario) – Updated for Load Forecast 2017 (PUB-MFR-65)



14
15

1 Manitoba Hydro reproduced at page 3 of Exhibit MH-52 the above chart using domestic
 2 load “at meter”, which is the relevant metric given it is “at meter” by which Manitoba
 3 Hydro bills its customers. As can be seen, net unit costs are pushing right to the top of
 4 the range from NFAT.
 5

6 **Figure 4.4 Net Unit Cost to Domestic Sales (\$/kWh)**



7
 8

9 Finally, in Figure 1.1 of Exhibit MH-52 Manitoba Hydro provided the following table:

10

11

1 **Figure 4.5 Comparison of MH16 Update with Interim (at MH15 Rate Increases and 20**
 2 **Year WATM) with MH15**

	MH16	MH15	Difference	% Difference
2017-2027 Domestic Revenue	\$20,865	\$22,265	(\$1,400)	-6.3%
2017-2027 Export & Other Revenue	\$7,193	\$8,746	(\$1,553)	-17.8%
2017-2027 Net Income	(\$325)	\$607	(\$932)	-153.5%
Adjusted for Current 2017/18 and 2018/19 Outlook*	(\$78)		(\$78)	
Adjusted for Keeyask In-Service delayed 21 months**	(\$750)		(\$750)	
Proforma 2017-2027 Net Income Comparison	(\$1,153)	\$607	(\$1,760)	-290.0%
2024 Net Income	(\$222)	\$56	(\$278)	-496.4%
2024 Net Debt	\$24,811	\$22,449	\$2,362	10.5%
2024 Equity Ratio	12%	12%	-	
2027 Net Income	(\$160)	\$232	(\$392)	-169.0%
2027 Net Debt	\$25,060	\$21,838	\$3,222	14.8%
2027 Equity Ratio	10%	14%	-4.0%	
2024 Net Cost per GWh***	\$0.1000	\$0.0900	\$0.0100	11.1%
Increase from 2017/18 Net Cost per GWh	65.0%	32.0%	33.0%	
Cumulative Rate Increase after 2017/18	30.0%	30.0%	0.0%	

3
 4
 5 This table reveals in comparison to MH15 a 500% decline in forecast net income for
 6 2023/24, a 170% decline in forecast net income for 2026/27 and an 11% increase in net
 7 unit costs. More urgently, this table shows that MH16 Update with Interim (at MH15
 8 rates) projects a 65% increase in net unit costs per GWh between 2017/18 and 2023/24
 9 wherein Keeyask is fully in service. Under MH15 the increase in net unit costs over that
 10 time frame was forecast at 32%. Cumulative rate increases of 3.95% from 2017/18
 11 would result in a 30% cumulative rate increase which Manitoba Hydro submits is wholly
 12 insufficient in the face of unit cost escalation of 65%.

13
 14 In Manitoba Hydro's view, there can simply be no basis for interveners to suggest there
 15 has not been any deterioration in Manitoba Hydro's financial outlook.

16
 17 Manitoba Hydro takes issue with the fact that not one intervener has brought forward
 18 an expert with any experience in operating a business, especially not one the size and
 19 complexity of an integrated utility like Manitoba Hydro. Not one intervener has brought
 20 forward an expert with any experience managing the risks associated with a multi-billion
 21 dollar balance sheet and debt portfolio. And not one intervener has brought forward an
 22 expert with any credible experience working in the capital markets and dealing with
 23 investors. Manitoba Hydro has this expertise and therefore can assert that growth and

1 the continued expectation of growth are fundamental in order to relieve financial
2 distress when it presents. Without growth, a business has lost the most vital tool a
3 business has to get itself out of trouble, which in Manitoba Hydro's case means too
4 much debt. The very best way to get out of this trouble is through growth; however, as
5 explained in the application materials, in direct evidence throughout the hearing, and as
6 summarized above, Manitoba Hydro cannot expect to do that anymore. As a result, the
7 business, as compared to its prior forecast, has deteriorated.

8
9 Between 2017 and 2027, aggregate net income has gone from a positive \$600 million to,
10 on a like basis, a loss of almost \$1.16 billion (not including any adjustment for the delay
11 in Keeyask planned in-service). Mr. Harper understood this in his evidence; it is
12 irrefutable (Transcript Pages 5406 to 5408).

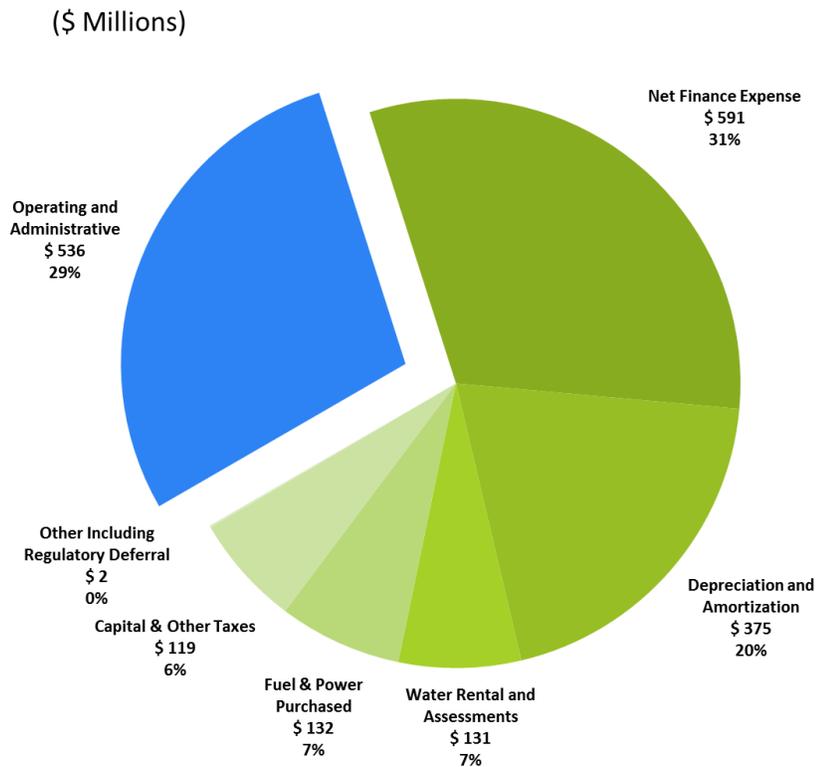
13
14 Manitoba Hydro feels it is important to remind the PUB that there was no commitment
15 at NFAT that if Manitoba Hydro got off track (with lower load growth, lower export price
16 appreciation, higher capital costs, drought or other events) that the proposed rate path
17 would remain at 3.95%. The 27 sensitivity scenarios reviewed at NFAT included
18 compensatory rate increases to deal with downside scenarios. As noted in the footnote
19 on page 5-3 of Exhibit MIPUG-13, Mr. Bowman's worst case scenarios included an
20 assumption of 5.48% rate increases until 2032 to offset the hypothetical downside
21 erosion that is now present in immediate effect. In other words, all of the analysis of
22 NFAT said Manitoba Hydro was going to need to act if things do not go to plan. As
23 demonstrated in MH16 Update with Interim, and throughout the GRA proceeding,
24 things are not going as planned and, to reiterate Mr. McCallum's testimony cited above,
25 Manitoba Hydro and the PUB must take action now.

1 **5 WITHOUT HIGHER RATE INCREASES MANITOBA HYDRO CANNOT SUPPORT ITS DEBT**

2 **5.1 Cost of Debt Financing is Manitoba Hydro’s Largest Expense**

3 As a capital intensive organization, Manitoba Hydro’s assets drive its costs. Interest
4 expense, incurred as a result of borrowing to fund asset investment, depreciation of
5 assets and capital taxes drives over 60% of the current corporate cost structure. Slide 10
6 from Manitoba Hydro’s Policy Panel Presentation, Exhibit MH-64, below, demonstrates
7 the breakdown of the expenses on the income statement for the 2016/17 fiscal year.
8

9 **Figure 5.1 Breakdown of Expenses**



10 **Source: Slide 10 of Exhibit MH-64**

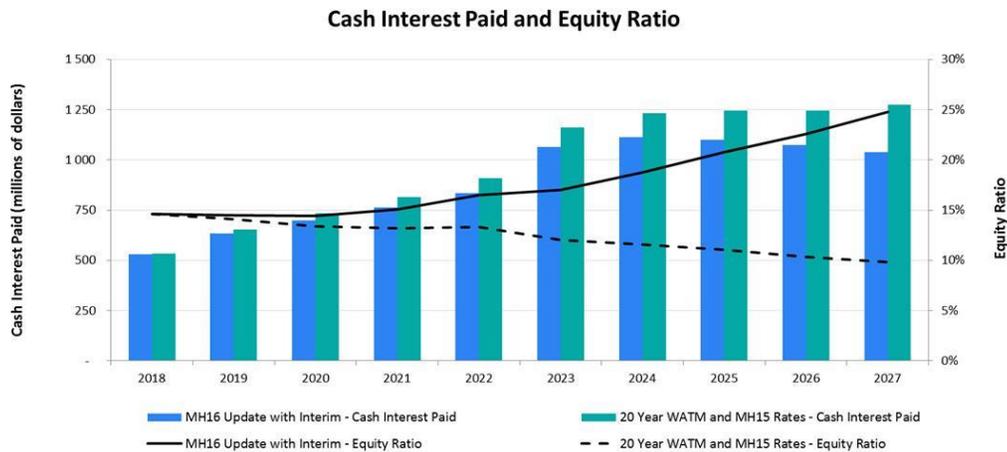
11
12
13 These costs will increase upon the completion of Bipole III and Keeyask adding nearly
14 another \$1 billion of annual depreciation and interest expense into Manitoba Hydro’s
15 revenue requirement once Keeyask is in service (PUB MFR 20).
16

17 Interest payments are, and will continue to be, Manitoba Hydro’s largest requirement
18 for cash outlays. As long as there are annual cash flow deficiencies, additional debt will
19 be needed to fund the business and cash interest paid will increase. This connection

1 between cash flow and capital structure supports the need for a deliberate and
2 sustained effort to restore the equity ratio (by lowering debt) in order to reduce the
3 need for cash (and rate revenue) to fund interest costs. The amount of debt is the most
4 significant driver of cash flow and financial health.

5
6 It is informative to consider the significant improvement to the Corporation's equity
7 ratio, and cost-savings available to ratepayers resulting from the reduction in total
8 interest by following the 7.9% rate path, rather than the 3.95% rate path, demonstrated
9 by Figure 1.11 from Manitoba Hydro's Written Rebuttal Evidence, Exhibit MH-52.

10
11 **Figure 5.2**



12
13 **Source: Exhibit MH-52, Page 16**

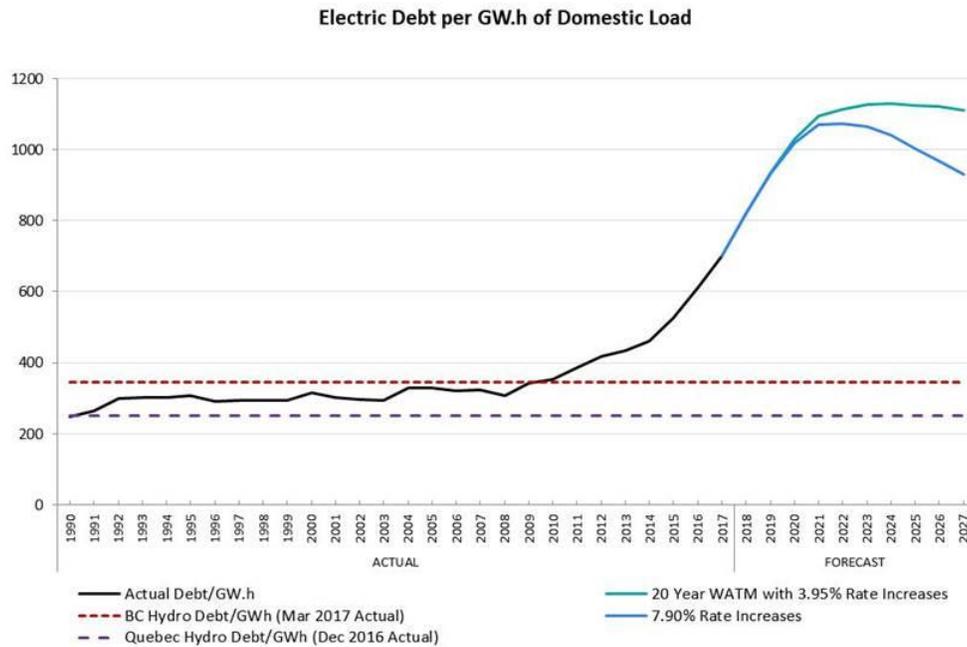
14
15 The negative net income and persistent annual cash flow deficiency under the 3.95%
16 rate path contributes to an equity ratio decline of 5% (from 15% down to 10%) over the
17 10-year forecast period. In contrast, the 7.9% rate path generates surplus cash
18 beginning in fiscal 2021, the cumulative cash flow deficiency is eliminated by fiscal 2022,
19 the equity ratio begins to improve, and cash interest paid is lower in each year of the
20 forecast and declines beginning in fiscal 2025.

21
22 **5.2 No Precedent for Pending Level of Debt Burden on Domestic Customers**

23 Manitoba Hydro's debt is growing out of all historical proportion to the size of the
24 business. Manitoba Hydro's debt per gigawatt hour of domestic load or consumption
25 has increased dramatically since 1990 as seen in Figure 1.16 of Exhibit MH-52.

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Figure 5.3



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Source: Exhibit MH-52, Page 25

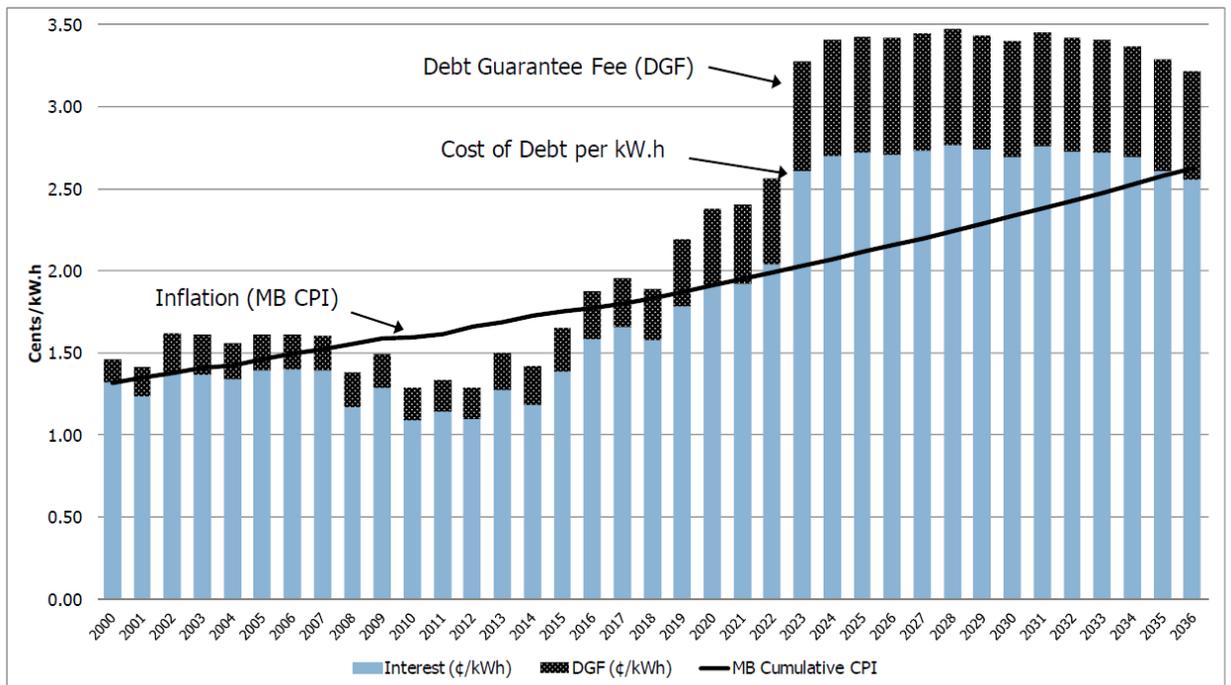
As shown on slide 20 of Exhibit MH-64, in 1990 Manitoba Hydro had almost \$250,000 of debt per gigawatt hour of annual domestic load. As borrowing increases for Keeyask and Bipole III, the debt per gigawatt hour of annual domestic load increases dramatically, and under a 3.95% rate plan this metric eventually climbs to over \$1.1 million per gigawatt hour and remains at that level. Relative to the size of Manitoba Hydro’s business, the Corporation is building to being roughly four times as indebted as it was immediately after the construction of Limestone. As compared to BC Hydro and Hydro Quebec, Manitoba Hydro is already much higher and will be multiples of their levels of relative indebtedness in the future. Domestic load is an appropriate measure by which to evaluate debt levels because it is a proxy for how much debt service will need to be carried by each kW.h of domestic sales. It is the domestic ratepayers that are responsible for this risk. If interest rates increase, every dollar of additional interest rate expense will need to be recovered from the domestic ratepayer. Understanding the degree of leverage which is placed upon domestic ratepayers is vital to appreciating the vulnerability of the situation. The MH16 Update with Interim rate path, beginning with the approval of the requested rate increases in this Application will begin to reduce the risk facing the Corporation and its ratepayers, but even this will not restore debt to the

1 relative levels consistent with past practice, or to the levels consistent with its peers, BC
2 Hydro or Hydro Quebec.

3
4 Figure 2 in the response to MH-MIPUG (Bowman) 23 illustrates the pressure debt is
5 going to put on domestic ratepayers (reproduced below).
6

7 **Figure 5.4**

Figure 1: Manitoba Hydro Cost of Debt (Interest Payments & Debt Guarantee Fee) Comparison to MB CPI (cents/kW.h) MH16 w. Interim Update and MH15 Rate Increases – 2000 to 2036



8
9 **Source: MH-MIPUG (Bowman) 23, Page 2**

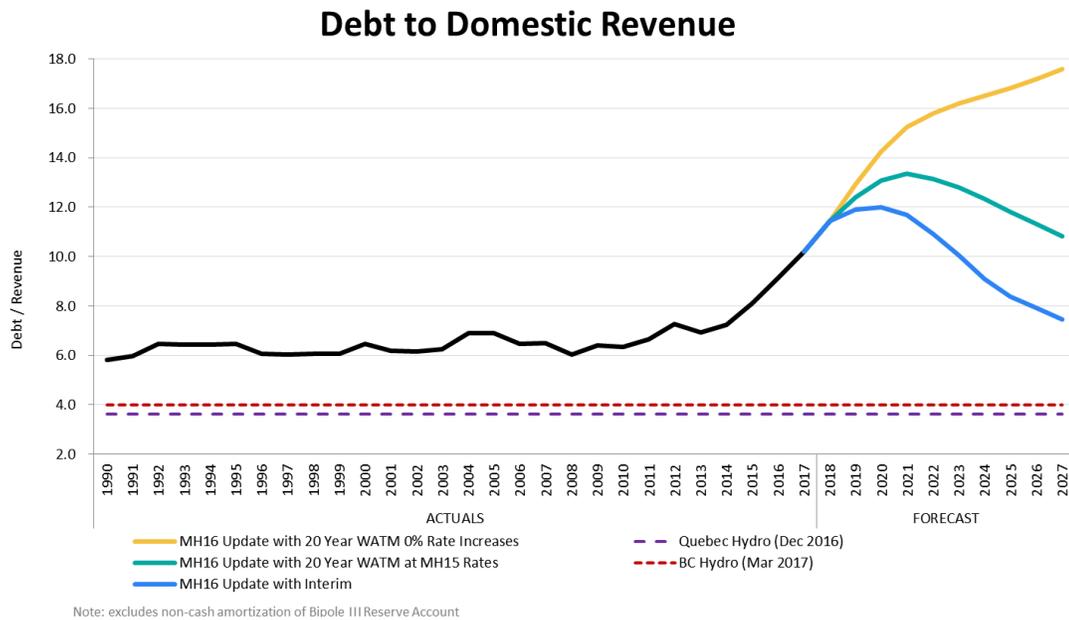
10
11 As can be seen from the chart above, the growth in the amount of interest expense per
12 kW.h is dramatically outpacing inflation, notwithstanding declining interest rates from
13 2010 to 2017. This chart is prepared based on hydraulic generation. This chart is
14 showing that the interest expense to be borne by each kW.h of generation will increase
15 by more than 100% between 2018 and 2024. Were it to be done on domestic load at
16 meter (which is the appropriate standard given where the liability for interest rate
17 volatility resides), the pace of escalation would be even more dramatic. As shown in
18 PUB MFR 18, cash interest paid in 2017/18 is approximately \$900 million which would
19 represent almost 60% of domestic revenue (including revenue allocated to the Bipole III

1 reserve). Therefore debt per kW.h is at least doubling for an annual cash burden that is
2 already 60% of domestic rate revenue.

3
4 Manitoba Hydro has provided evidence demonstrating the interest costs as a share of
5 domestic revenue. Once the major projects conclude and all of the interest flows
6 through to the income statement, over 60% of each domestic revenue dollar is going to
7 pay interest (Exhibit MH-64, Slide 21). There is not much revenue left with which to run
8 the business and maintain assets. Should interest rates increase more than anticipated,
9 this situation will only worsen, as shown in the Key Variable Sensitivity Impacts provided
10 in the response to PUB/MH I-45.

11
12 The following chart from Exhibit MH-64 compares debt to domestic revenue.

13
14 **Figure 5.5**



15
16 **Source: Exhibit MH-64, Slide 28**

17
18 Similarly, the relationship of debt to domestic activity is critical as it is domestic
19 customers who absorb 100% of the volatility that comes from any of the risks that face
20 Manitoba Hydro's business including interest rates, water conditions and export prices.
21 Since the in-service of Wuskwatim, debt has grown out of all proportion to Manitoba
22 Hydro's business activities. This metric is now double historic norms for Manitoba
23 Hydro and triple that of two of Manitoba Hydro's Canadian peers. MH16 Update with

1 Interim is more aggressive in bringing this relationship back toward pre-build norms
2 however at the end of 2027 Manitoba Hydro still forecasts debt levels, on a relative
3 basis, which are 30% above levels seen between 1990 and 2010. The 3.95% path does
4 not make much progress on improving this metric. While domestic revenue goes up
5 with the cumulative 47% rate increases over a decade, the lack of income and cash flow
6 do not allow for debt retirement.

7 8 **5.3 Debt Management Can't Mitigate Longer Term Risk**

9 Manitoba Hydro must manage interest rate risk in order to control finance expense. In
10 the short term this can be accomplished by managing refinancing risk through prudent
11 debt management strategies. However, in the intermediate and longer term interest
12 rate risk and finance expense can only be managed by reducing the total amount of
13 debt. Manitoba Hydro's volume of debt is dependent upon the growth of the
14 investment in assets. This growth must be funded by cash from operations or debt
15 financing. The additional revenue generated by the requested 7.9% rate increase is a
16 first step on a ten year path that, in the words of Mr. McCallum (Transcript Page 184), is
17 "about getting our debt under some control to take some of the risk out of a perilous
18 and unprecedented financial situation".

19
20 Manitoba Hydro will need to go to the markets to borrow between \$19 and \$23 billion
21 over the coming decade which will increase the Corporation's exposure to interest rate
22 risk. The table below illustrates borrowing requirements under two rate increase paths
23 and is drawn from Exhibit MH-64, slide 36. Over the period, virtually all of Manitoba
24 Hydro's debt will need to be initially borrowed and/or refinanced. This exposes
25 ratepayers to risks from increases to interest rates. Should those interest rates increase
26 unexpectedly, even in the order of 1%, this will have dire consequences for ratepayers.

1

Figure 5.6

In Billions of Dollars	MH Plan	3.95% / 12 Year WATM
2017/18 - 2021/22 Borrowing	\$13.5	\$14.1
2022/23 - 2026/27 Borrowing	\$8.8	\$9.7
2022/23 - 2026/27 Cash Flow	<u>(\$3.1)</u>	<u>(\$0.4)</u>
Total 10-Year Borrowing	\$19.2	\$23.4

2

3

Source: Exhibit MH-64, Slide 36

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In the 2023-2027 timeframe, the higher cash flows from the 7.9% rate path limit new borrowing requirements by approximately \$1 billion and create surplus cash of \$3.1 billion that can be used to pay down debt as it comes due instead of refinancing debt. In contrast, there is virtually no debt retirement under the 3.95% rate path. As a result, all of this debt will be exposed to refinancing risk as it comes due. This was acknowledged by Morrison Park Advisors (“MPA”) during cross-examination when Mr. Colaiacovo stated, “Anything that is being refinanced within a period is subject interest rate risk within that period” (Transcript Pages 5130 to 5131). Interest rate exposure will be lessened with a 7.9% rate path by removing \$4 billion of debt from the balance sheet.

15

5.4 Debt to EBITDA is a Troubling Metric

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Debt to EBITDA provides another way of understanding how much debt a corporation’s cash flow is expected to service. Ratios of 6 and 7x are often considered highly leveraged. During cross-examination, MPA was referred the ratings methodology of Fitch Ratings (MPA Evidence filed on behalf of the Consumer’s Coalition, Exhibit CC-17, Page 116) which describes Debt to EBITDA ratios of greater than 8x as “Weaker” and indicative of an insufficient rate structure. MPA acknowledged that Fitch Ratings would be looking for a suitable rationale for a corporation with a ratio of eight times, including perhaps investment in a major capital program, and admitted that if the ratio were in the order of 12 times, and projected to worsen to 13 times that they would expect after completion of the capital program that it would start to improve. (Transcript Page 5059).

1 “MR. MATTHEW GHIKAS: Okay. And if we go to the weaker row, then,
2 under that column, we see greater than eight (8) times debt with a
3 suitable rationale can indicate deficient rate structure.

4 MR. PELINO COLAIACOVO: I -- I think you meant without a suitable --

5 MR. MATTHEW GHIKAS: Sorry, without a suitable rationale [can] indicate
6 deficient rate structure?

7 MR. PELINO COLAIACOVO: Correct. And

8 MR. MATTHEW GHIKAS: Right. So -- so you would expect that Fitch would
9 be looking for a suitable rationale, for example, they had already been
10 over eight (8) times for six (6) years.

11 MR. PELINO COLAIACOVO: And I think a suitable rationale is investment in
12 a major capital program, and -- and that's what that is actually about.

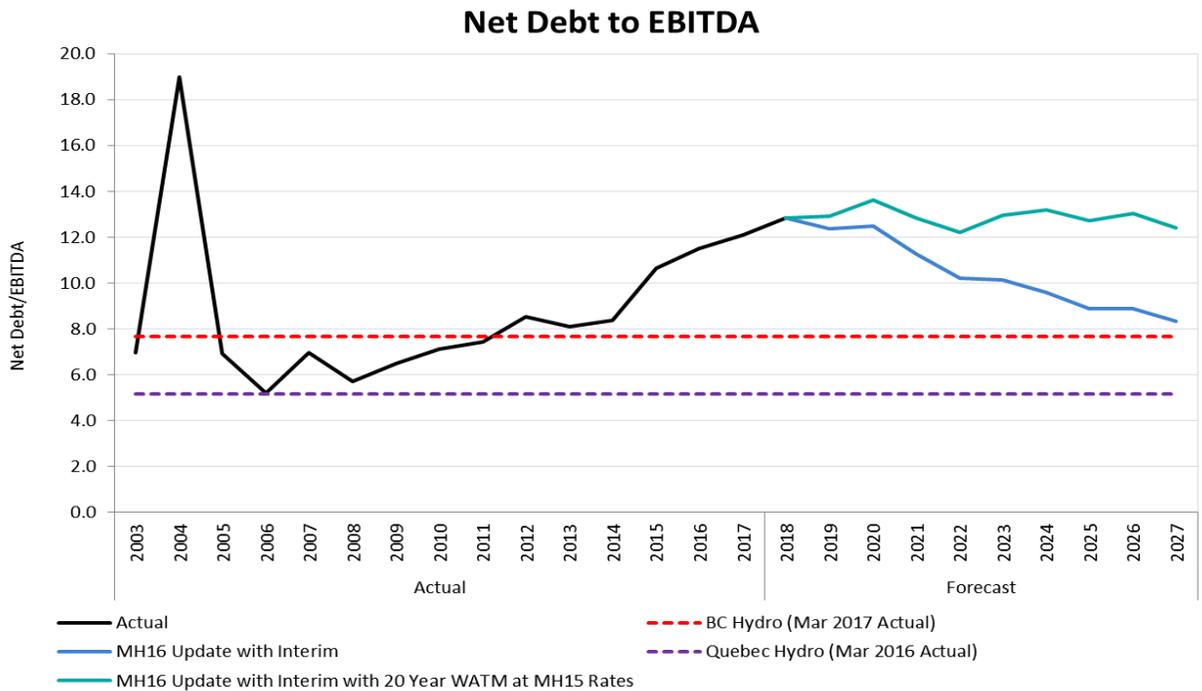
13 MR. MATTHEW GHIKAS: And they would be looking for a rationale. Would
14 you put it as the capital thing if the -- today it was a twelve (12) times and
15 was going to get worse to thirteen (13) times?

16 MR. PELINO COLAIACOVO: Yeah, and --but they would expect that after
17 the completion of the major capital expenditures, **that would start to**
18 **improve.**” (Emphasis Added)

19
20 The following graph from Exhibit MH-64 shows that Manitoba Hydro’s debt to EBITDA
21 has been steadily climbing even since before the start of the major build program.
22
23

1

Figure 5.7



2

3

Source: Exhibit MH-64, Slide 56

4

5

With a 3.95% rate path, this metric is forecast to reach nearly 14x before declining to the 13x range where it stays through 2027. This stands in stark contrast to what Mr. Colaiacovo asserts would be the expectation of ratings agencies who would expect to see recovery in the post-construction phase.

6

7

8

In 2003/04, when Manitoba Hydro lost over \$400 million during a drought, the Debt to EBITDA ratio spiked to over 18x before returning to historic levels on the back of lofty export revenues. It should be very concerning to the PUB that under a 3.95% rate path, Manitoba Hydro will be building debt to a level directionally consistent with the temporary level reached during a terrible drought – a time when the PUB was so concerned about Manitoba Hydro’s financial condition that it awarded the corporation a higher rate increase than requested (Order 101/04).

9

10

Mr. Colaiacovo spoke of the 2003/04 shock to cash flow in his testimony at Transcript Page 5053:

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12

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17

1 *“MR. MATTHEW GHIKAS: And in your – in your testimony yesterday, in*
2 *response to a question from member Kapitaný ...you referred back to the*
3 *early 2000s. 2003, you believed went -- that was an extremely short,*
4 *sharp shock in that period in the second lowest water year ever. Do you*
5 *recall that generally?*

6 *MR. PELINO COLAIACOVO: Yes.*

7 *MR. MATTHEW GHIKAS: Okay. And you indicated that Manitoba --*
8 *Manitoba Hydro's cash flow plummeted through the floor?*

9 *MR. PELINO COLAIACOVO: That's correct.*

10 *MR. MATTHEW GHIKAS: And were you aware that during that period, this*
11 *metric was only at nineteen (19) times?*

12 *MR. PELINO COLAIACOVO: That may well-- very well be the case.”*

13
14 MPA reports that the credit rating agency S&P regards Debt to EBITDA as one of two
15 primary metrics that it focuses on with respect to cash flow (Exhibit CC-17, Page 33).
16 MH16 Update with Interim takes action on this metric although by the end of 2027, it
17 remains elevated from historic norms for Manitoba Hydro, above peers' current metrics
18 and above levels categorized as evidence of rate inadequacy by Fitch Ratings.

19 20 **5.5 Capital Markets Are Concerned with Rate Inadequacy**

21 Manitoba Hydro's financial health and deteriorating financial metrics due to the
22 imbalance between the growth of debt and lack of revenues have been of concern to its
23 credit rating agencies.

24
25 In Moody's November 28, 2017 Report on the Manitoba Hydro Electric Board filed as
26 Exhibit MH-61 in confidence, the rating agency states:

27
28 *“While rates increases are nominally set on a cost-of service basis rate increases*
29 *in recent years have clearly not kept up with costs as evidenced by ongoing weak*
30 *financial metrics.”*

31
32 Additionally:

33
34 *“As part of its debt management strategy, Manitoba Hydro targets certain*
35 *financial metrics such as an interest coverage ratio greater than 1.8x and equity-*

1 *to-capitalization greater than 25%. However, both targets are not expected to be*
2 *met for an extended period of time due to the large generation and transmission*
3 *projects currently underway such as Keeyask and Bipole III and limited rate*
4 *increases. For example on a last twelve month basis Moody's adjusted EBITDA to*
5 *interest expense was 1.3x and debt to book capitalization was 88%. These*
6 *financial metrics are among the weakest, if not the weakest, of any of Manitoba*
7 *Hydro's peers, including vertically integrated provincially owned crown*
8 *corporations in Canada."*
9

10 In Exhibit MH-71 (DBRS Provincial Outlook Report November 28, 2017) it is reported
11 that Manitoba Hydro's debt as a percentage of GDP is larger than its Canadian peers. In
12 fact, by adding the Manitoba Hydro-Electric Board self-supported debt of 28.8% at
13 March 31, 2017 (Exhibit MH-71, Page 95), to the Manitoba debt percentage of
14 approximately 45% (Manitoba Hydro letter dated May 5, 2017, Exhibit MH-4, Page 6),
15 Manitoba rivals Newfoundland for the highest debt burden as a percentage of GDP.
16

17 Rating agencies and investors clearly understand that elevated debt leaves an issuer
18 much more susceptible to risks, particularly adverse interest rate movements. As noted
19 in the response to PUB/MH I-45, Figure 4.4 - Key Variable Sensitivity Impacts to Retained
20 Earnings filed in Tab 4 of the Application, has been updated based on MH16 Update
21 with Interim Rate. The projected impact of a + 1% increase in Interest rates results in a
22 cumulative decrease to retained earnings of \$885 million to 2027/28. This results in the
23 equity target not being reached until fiscal 2029 despite 7.9% rate increases for six
24 years. MH16 Update with MH15 rate increases, with a greater debt burden, is prone to
25 a greater degree of interest rate risk than MH16 Update with Interim. Given the 25%
26 equity target is not reached until fiscal 2034 with the base case MH15 rate increases, a +
27 1% increase in interest rates would further pressure Manitoba Hydro's poor financial
28 metrics.
29

30 **5.6 Financial Targets Are Not Met Without Higher Rate Increases**

31 On page 43 of their report (Exhibit CC-17), MPA makes a number of assertions about the
32 sufficiency of various rate paths including the statement that:
33

1 *“the 3.95% rate path is reasonably robust from a cash flow perspective for the*
 2 *first 10 years of the modeling period. After 2030, however, reducing the rate*
 3 *path down to 2% increase exposes the corporation to too much risk.”*

4
 5 MPA goes on to states “It is not clear why annual rate increases were not kept at 3.95%
 6 for additional years beyond 2028/29 but based on this modeling, it would definitely be
 7 necessary.” MPA points to sensitivity analysis drawn from PUB/MH II-41 and points out,
 8 in support of the need for the 3.95% rate increases to continue beyond 2028/29, that
 9 “net income actually becomes negative at the P20 position for more than half of the
 10 years of the model” (line 17-18, page 43).

11
 12 The following table, sourced from PUB/MH II-41, sets out annual net income and
 13 EBITDA to Interest ratio (both under the MH15 rate path) at the P20 level for the years
 14 from 2028/29 to 2035/36 when the target equity ratio of 25% is nearly met (at the P50
 15 level).

16
 17 **Figure 5.8**

	MH16 Update with Interim at MH15 Rates							
	2029	2030	2031	2032	2033	2034	2035	2036
P20 Net Income	(\$130)	(\$73)	(\$53)	\$16	\$67	\$137	\$217	\$216
P20 EBITDA to Interest	1.58x	1.64x	1.64x	1.70x	1.75x	1.83x	1.91x	1.93x

18
 19 **Source: PUB/MH II-41**

20
 21 The next table, sourced from Appendix 1.3 to Exhibit MH-52 lays out net income and the
 22 EBITDA to Interest ratio but instead at the P50 (i.e. reference) level. This scenario is
 23 MH16 Update with Interim with MH15 Rates and 20 Year WATM.

24
 25 **Figure 5.9**

	Exhibit MH-52 (Rebuttal), Appendix 1.3							
	2024	2025	2026	2027	2028	2029	2030	2031
P50 Net Income	(\$222)	(\$176)	(\$226)	(\$160)	(\$91)	\$17	\$100	\$182
P50 EBITDA to Interest	1.47x	1.52x	1.49x	1.54x	1.60x	1.69x	1.78x	1.87x

26
 27 **Source: Exhibit MH-52, Appendix 1.3**

1 In comparing the two tables Manitoba Hydro notes a paradox in MPA's assertions on
2 rate inadequacy. The "reasonably robust" rate path for the first 10 years produces large
3 losses in the reference case for many years along with, for the most part, the EBITDA to
4 Interest minimum target of 1.80x not being met. These losses are well in excess of the
5 P20 level losses Morrison Park cites in support of it being "too much risk to the
6 corporation" to reduce the rate path to 2% beyond 2028/29. Likewise the EBITDA to
7 interest ratio is considerably lower. It is especially noteworthy that the income levels
8 and EBITDA to Interest ratios cited as being "too much risk" occur at the P20 level
9 meaning there is only a 20% chance (according to this analysis) that net losses would be
10 worse. Meanwhile at the P50 level in the comparison, net losses are substantial larger
11 and the interest coverage levels lower while having a 50% chance of being even worse
12 and yet are "reasonably robust". Manitoba Hydro is unable to reconcile how a forecast
13 of comparatively modest losses and stronger interest coverage ratios with relatively
14 lower likelihood can be deemed "too much risk" and yet larger losses that have a higher
15 level of certainty of occurring are deemed "reasonably robust". Manitoba Hydro is
16 unable to reconcile how relatively stronger results much further in the future are a
17 cause for concern while even larger losses and weaker metrics 5-10 years from now are
18 "reasonably robust". This is particularly confusing given the increases in potential
19 variance are further into the future. For example, under the MH15 rate path, P50 net
20 income for 2034 is estimated to be \$530 million but with a range of a \$207 million loss
21 (P05) to \$1.6 billion of net income (P95).

22 23 **5.6.1 EBITDA to Interest**

24 EBITDA is a very commonly used proxy for cash flow before any interest payments or
25 capital expenditures. MPA describes it this way at page 8 of their report (Exhibit CC-17):

26
27 *"The Interest Coverage Ratio...is often considered an important metric when*
28 *assessing the credit-worthiness of an enterprise, because it provides information*
29 *about the sufficiency of cash flow to cover interest cost...while this ratio serves*
30 *as an indicator of the sufficiency of cash flow, it is an "accounting" measure and*
31 *not a true "cash flow" measure of the results of the period for which the*
32 *calculation is being made". (Emphasis by MPA)*

33
34 Manitoba Hydro concurs with the above statement. However, at page 42 to 43 of
35 Exhibit CC-17, MPA states:

1
2 *At the P01 position of the EBITDA to Interest plot on the 3.95% rate path, the*
3 *ratio is never below 1. It should be noted that a ratio of 1 means that operating*
4 *income is just sufficient to cover finance expense costs. In the parlance of the*
5 *Moody's and DBRS, as long as Manitoba Hydro is able to continue to cover all of*
6 *its costs – including operating costs and interest – it will continue to be regarded*
7 *as “self-supporting”, and not a burden to the Province”*
8

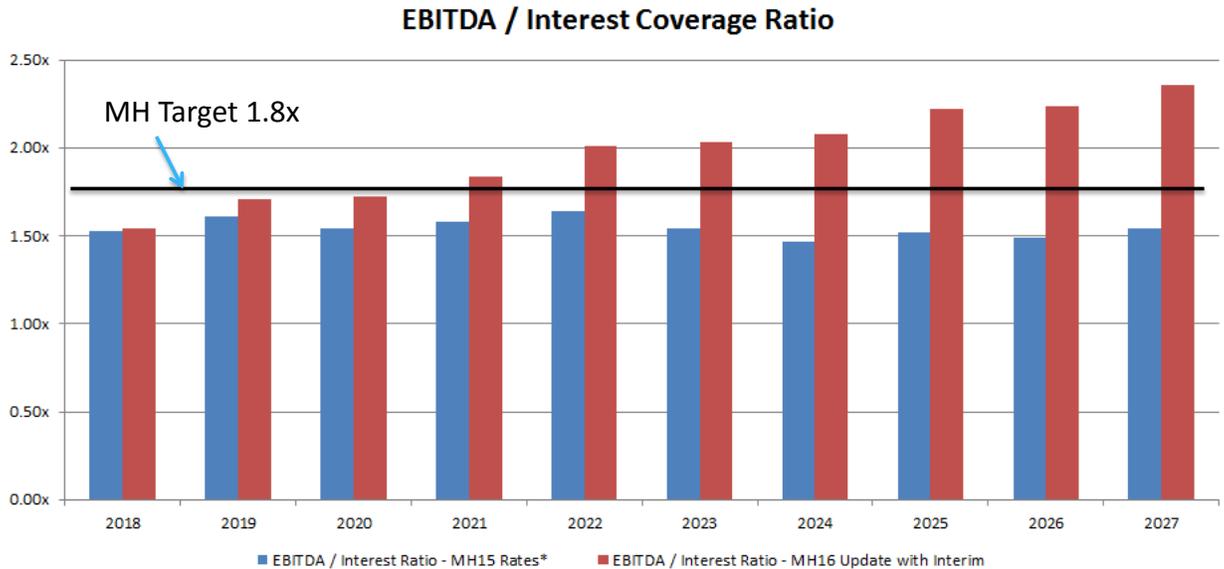
9 MPA's use of the EBITDA to Interest coverage ratio in support of assertions regarding
10 Manitoba Hydro's self-supporting status and overall rate adequacy is significantly
11 flawed. An EBITDA to Interest coverage ratio of 1.0x on a sustained basis necessitates
12 significant borrowing of new debt every year to meet sustainment capital needs and
13 ongoing obligations. There is no argument that this is a financially prudent path or one
14 that would be endorsed by capital markets participants as evidence of being self-
15 supporting. Manitoba Hydro cannot continue to operate and generate EBITDA in the
16 first instance without replenishing its assets. Manitoba Hydro cannot sell from inventory
17 like another business can when its plant fails. Manitoba Hydro requires its assets to be
18 in-service in order to generate revenue. During his testimony, Mr. Colaiacovo
19 acknowledged that at an EBITDA to Interest level of 1.0x, no cash would remain, after
20 meeting interest payments, to be used for any of capital expenditures, debt reduction,
21 mitigation or City of Winnipeg liabilities (Transcript Pages 5068 to 5071). Exhibit MH-52,
22 Figure 1.12 (reproduced in sub-section EBITDA to Cash Burdens below), demonstrates
23 that the annual capital expenditures and other cash burdens on Manitoba Hydro are in a
24 narrow range between \$723 million and \$822 million annually over the next 10 years.
25 At an EBITDA to Interest level of 1.0x this would reflect, dollar for dollar, the
26 incremental debt Manitoba Hydro would need to borrow to maintain its operations and
27 meet its mandate.

28
29 Without an EBITDA to Interest ratio significantly above 1.0x, Manitoba Hydro is deficit
30 funding its ongoing operations which, if sustained, is the very definition of not being
31 self-supporting.

32
33 The following chart compares Manitoba Hydro's EBITDA to Interest ratio under MH16
34 Update with Interim and the same scenario with MH15 rates and 20 Year WATM
35 (Exhibit MH-52, Appendix 1.3):

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Figure 5.10



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Source: Exhibit MH-52, Appendix 1.3

As can be seen from the above, under the 3.95% rate plan, Manitoba Hydro never reaches its minimum target and in fact barely crosses 1.50x throughout the period and with no pattern of improvement particularly after the in-service of Keeyask. Manitoba Hydro expects this would be deeply concerning to bond investors who watch trends carefully.

The table is a reproduction of Figure 1.10 from Exhibit MH-52, page 15. It sets out Manitoba Hydro's cash flows under the MH15 rate plan (Exhibit MH-52, Appendix 1.3):

1

Figure 5.11

millions of dollars

	Actual		Forecast									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Receipts from Customers	1 907	1 997	2 152	2 170	2 173	2 371	2 577	2 734	2 821	2 931	2 897	3 011
Payments to Suppliers and Employees	(736)	(933)	(892)	(843)	(870)	(885)	(894)	(903)	(935)	(953)	(952)	(966)
Interest Paid (Net of All Capitalized Interest)	(520)	(536)	(528)	(641)	(711)	(789)	(889)	(1 155)	(1 227)	(1 239)	(1 241)	(1 266)
Bipole III and Other Business Operations Capitalized Interest*	(107)	(141)	(197)	(93)	(21)	(18)	(16)	(19)	(19)	(19)	(18)	(20)
Business Operations and Deferred Capital Expenditures:												
Business Operations Capital Expenditures**	(616)	(578)	(586)	(566)	(554)	(544)	(525)	(532)	(544)	(601)	(627)	(646)
Demand Side Management	(54)	(50)	(55)	(97)	(92)	(87)	(85)	(64)	(58)	(60)	(64)	(68)
Mitigation and Other Deferred Expenditures	(22)	(5)	(27)	(26)	(23)	(23)	(22)	(22)	(21)	(22)	(21)	(22)
Ineligible Overhead	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	-	-	-	-
Cash From Operations Less Capex	(167)	(267)	(153)	(116)	(119)	5	126	19	16	38	(26)	24
Mitigation, Major Development & Other Liability Payments	(26)	(13)	(59)	(46)	(36)	(79)	(98)	(88)	(84)	(84)	(71)	(70)
City of Winnipeg Payments	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
Cash Flow (Deficiency)/Surplus	(209)	(296)	(228)	(178)	(170)	(89)	12	(85)	(84)	(62)	(113)	(62)
Cumulative Cash Flow (Deficiency)/Surplus			(228)	(406)	(576)	(665)	(653)	(739)	(823)	(884)	(998)	(1 060)

*Bipole III and Other Sustaining Capitalized Interest does not include any capitalized interest associated with Keeyask, MMTP or GNTL.

**Represents Business Operations Capital Expenditures and MNG&T Capital Expenditures of a sustaining nature (excluding Bipole III costs).

2

3

Source: Exhibit MH-52, Appendix 1.3

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As can be seen, and comparing with the EBITDA to Interest graph above, an interest coverage ratio in the order of 1.50x following the 3.95% rate path translates to significant, repetitive cash flow deficiency. Over the 10 year horizon, the ongoing operations of Manitoba Hydro require \$1.1 billion of additional borrowing over and on top of the borrowing necessary to complete the major capital projects. In only one year (2021/22 at \$12 million) does Manitoba Hydro generate any positive cash flow from its operations.

EBITDA to Interest Coverage is often regarded as a solvency metric in that it indicates a company's ability to service its interest costs out of operating earnings (before non-cash depreciation expense). However, as a test of financial durability and cash flow sufficiency, the metric has important shortcomings. It presumes that the cash interest requirements of the business can assert primacy over all the other cash burdens on the company such as capital reinvestment or payment of other contractual liabilities. In actual fact, EBITDA Interest Coverage does not consider that, other than under very short time frames, Manitoba Hydro must fund both its interest costs and its capital and other requirements. As Mr. McCallum noted (Transcript Page 225) *"When elements of the system wear out and fail, which happens every day, we have to replace them or we are not meeting our commitments to Manitobans."* If Manitoba Hydro does not have sufficient cash flow after interest payments to fund its ongoing capital and other cash

1 needs then it cannot support its revenue and meet its mandate without borrowing
2 money.

3
4 Mr. Colaiacovo, at Transcript Page 4944, describes Manitoba Hydro's EBITDA to Interest
5 target of 1.8x as *"reasonable because it's consistent with targets that public power*
6 *utilities in the United States use, and one point five (1.5) to two (2) times, as Moody's*
7 *recognizes is a reasonable target for a – a public power utility."* Likewise, at slide 33 of
8 MPA's direct evidence (Exhibit CC-45), MPA asserts that *"1.8x is a "healthy" margin that*
9 *gives comfort that under "normal" conditions, Manitoba Hydro will have **plenty of***
10 ***cashflow to satisfy obligations"** (Emphasis Added). MPA further states that "for Public*
11 *Power Utilities 1.5x to 2.0x interest coverage is consistent with an "A" rating" by*
12 *Moody's. This stands in direct contrast to page 9 of Exhibit CC-17 wherein at line 13-15*
13 *wherein it is stated "This measure alone does not clarify whether the company's debt is*
14 *increasing, since there is no information captured in this metric about the size of capital*
15 *expenditures".*

16
17 Manitoba Hydro asserts that the Moody's test is not EBITDA to interest but rather debt
18 service coverage given that is how it clearly labeled in the referenced Moody's report.
19 Mr. Colaiacovo acknowledged this at transcript page 5072. During cross-examination,
20 Manitoba Hydro questioned Mr. Colaiacovo as to whether adjusted debt service
21 coverage included principal payments:

22
23 *"MR. PELINO COLAIACOVO: Not always. It actually just depends on the*
24 *arrangements of the Utility.*

25 *MR. MATTHEW GHIKAS: In common financial discourse debt service*
26 *generally includes interest and principal, doesn't it?*

27 *MR. PELINO COLAIACOVO: So it depends on your financial arrangements.*
28 *Debt service coverage ratio is a typical term but in some instances debt*
29 *service coverage ratio refers only to interest and some instances it refers*
30 *interest and principal" (Transcript Page 5072).*

31
32 Manitoba Hydro submits that the evidence in this respect is unclear as to whether
33 Moody's debt service coverage test would be applied to Manitoba Hydro using a
34 calculation of interest or interest and principal payments. Nonetheless, even by the less
35 stringent measure, Manitoba Hydro does not sustain itself at even the bottom end of

1 Moody's standard on a sustained basis and in fact does not meet its own internal target
 2 of 1.8x until 2030/31.

3 4 **5.6.2 EBIT to Interest**

5 The following table shows Manitoba Hydro's key financial metrics as well as other
 6 informative metrics.

7
8 **Figure 5.12**

Financial Ratios:	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Equity Ratio (Target > 25%)										
MH16 Update with Interim	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
MH15 Rates	15%	14%	13%	13%	13%	12%	12%	11%	10%	10%
Capital Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.40 x	1.48 x	1.47 x	1.88 x	2.34 x	2.25 x	2.37 x	2.34 x	2.20 x	2.29 x
MH15 Rates	1.39 x	1.33 x	1.15 x	1.36 x	1.59 x	1.30 x	1.21 x	1.20 x	1.10 x	1.18 x
EBITDA Interest Coverage Ratio (Target > 1.80x)										
MH16 Update with Interim	1.54 x	1.71 x	1.72 x	1.84 x	2.01 x	2.03 x	2.08 x	2.22 x	2.24 x	2.36 x
MH15 Rates	1.53 x	1.61 x	1.54 x	1.58 x	1.64 x	1.54 x	1.47 x	1.52 x	1.49 x	1.54 x
Other Metrics:										
EBIT Interest Coverage Ratio (Target > 1.20x)										
MH16 Update with Interim	1.10 x	1.21 x	1.20 x	1.31 x	1.45 x	1.38 x	1.36 x	1.47 x	1.45 x	1.54 x
MH15 Rates	1.10 x	1.13 x	1.03 x	1.07 x	1.12 x	0.95 x	0.83 x	0.86 x	0.82 x	0.88 x
Net Debt										
MH16 Update with Interim	\$ 18 473	\$ 20 743	\$ 22 407	\$ 23 296	\$ 23 609	\$ 23 388	\$ 22 831	\$ 22 201	\$ 21 613	\$ 20 947
MH15 Rates	\$ 18 474	\$ 20 825	\$ 22 657	\$ 23 809	\$ 24 496	\$ 24 761	\$ 24 811	\$ 24 877	\$ 24 994	\$ 25 060

9
10 **Source: Exhibit MH-64, Slide 53**

11
12 Mr. Bowman points to the EBIT / Interest ratio as:

13
14 *“the normal regulatory basis for determining an annual Revenue Requirement.*
 15 *The best metric used by Manitoba Hydro to measure this is the previous EBIT*
 16 *Interest Coverage ratio. Achieving an EBIT Interest Coverage ratio above 1.0x*
 17 *means that debt costs for the year can be funded from revenues for the year.*
 18 *The previous EBIT Interest Coverage ratio targeted 1.2 or better, reflecting a*
 19 *cushion above break even” (MH-MIPUG (BOWMAN)-12).*

20
21 The preceding table demonstrates that the 3.95% rate plan which Mr. Bowman
 22 advocates grossly fails his preferred test. Under the MH15 rate plan, Manitoba Hydro's
 23 EBIT to Interest ratio declines below 1.0 indicating, according to Mr. Bowman, that debt
 24 costs are not being funded by revenues.

1
2 More importantly, as Ms. Stephen testified (Transcript Page 953), Moody's has
3 expressed concern to Manitoba Hydro with respect to the EBIT ratio falling below 1 for
4 several years under a 3.95% rate plan. Ms. Stephen also testified that Moody's
5 cautioned that if Manitoba Hydro is viewed as being unable to service its debt, and no
6 steps are taken to mitigate the circumstances, the rating agency may change the self-
7 supporting status of Manitoba Hydro's debt.

8 9 **5.6.3 Capital Coverage Ratio**

10 Mr. Bowman asserts that because the Capital Coverage Ratio is greater than 1.2x under
11 the MH15 rate plan that Manitoba Hydro is attaining its goal to "*meet all financial*
12 *obligations including debt service and capital reinvestment out of the revenues of the*
13 *Corporation*". However, as noted in its evidence, there are shortcomings in Manitoba
14 Hydro's capital coverage ratio which must be recognized in order to properly determine
15 the ratio.

16
17 Firstly, certain projects are included in "*Major New Generation and Transmission*" by
18 virtue of their individual size resulting in the true sustainment capital needs of Manitoba
19 Hydro's operations being understated. The exclusion of other non-discretionary cash
20 payments such as mitigation, development and other liability payments and the annual
21 payment to the City of Winnipeg compounds the understatement.

22
23 Secondly, without making any adjustment for capitalized interest on funds borrowed to
24 finance reliability and sustainment projects like Bipole III, cash flow from operations (the
25 numerator in the formula) essentially excludes the interest paid which is an immediate
26 and ongoing cash outlay by the Corporation. Mr. Bowman's conclusion that the capital
27 coverage ratio is maintained at or above target (1.2x) for the entire 20 year forecast
28 under the 3.95% rate path (Pre-Filed Testimony of Patrick Bowman, on behalf of the
29 Manitoba Industrial Power Users Group, Exhibit MIPUG-13, Page 5-10) fails to make the
30 adjustments noted above or to acknowledge the declining trend line over the forecast
31 period. Mr. Bowman asserts at lines 24-26, page 4-5 of MIPUG-13 that after 2022/23
32 Manitoba Hydro would be "*rapidly retiring debt*" in the absence of Major New
33 Generation and Transmission investments. In fact, as demonstrated in the table above
34 (Exhibit MH-64, Slide 53), Manitoba Hydro's net debt actually grows by \$300 million

1 between 2022/23 and 2026/27 under the MH15 rate plan disproving Mr. Bowman's
 2 assertion that a sufficient capital coverage ratio is indicative of "rapidly retiring debt".
 3

4 **5.6.4 EBITDA to Cash Burdens**

5 Manitoba Hydro's ongoing, repetitive capital and other cash obligation needs in its core
 6 operations are anticipated to range between \$700 million and \$800 million per year as
 7 noted in the line "Capital and Other Needs" from the table below. This table reproduces
 8 Figure 1.12 of Exhibit MH-52 wherein the EBITDA interest coverage ratio is adjusted to
 9 include all the fixed burdens on Manitoba Hydro under the MH15 rate path. As can be
 10 seen, and consistent with its evidence that it is and will be "deficit funding" its core
 11 operations, other than in 2021/22 Manitoba Hydro never reaches parity or 1.0x wherein
 12 it has sufficient EBITDA to meet all of its cash obligations.
 13

14 **Figure 5.13**

	<i>millions of dollars</i>									
	Forecast									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Net Income	90	128	33	80	141	(66)	(222)	(176)	(226)	(160)
Net Finance Expense	573	677	753	839	925	1 179	1 251	1 263	1 263	1 283
Capitalized Interest	359	320	318	333	290	55	19	19	18	20
Depreciation and Amortization*	408	482	548	596	643	735	823	840	856	870
Corporate Allocation	8	8	8	8	7	7	7	7	7	7
EBITDA Numerator	1 439	1 614	1 661	1 856	2 006	1 911	1 880	1 953	1 918	2 019
Interest	939	1 003	1 078	1 178	1 221	1 241	1 277	1 288	1 287	1 309
Capital and Other Cash Needs	763	772	740	769	766	742	723	783	799	822
Cash Burdens (Denominator)	1 703	1 775	1 819	1 947	1 987	1 983	2 000	2 071	2 087	2 131
EBITDA / Ongoing Cash Burdens	0.85	0.91	0.91	0.95	1.01	0.96	0.94	0.94	0.92	0.95
Equity Ratio	15%	14%	13%	13%	13%	12%	12%	11%	10%	10%

15 *Including related items in Net Movement.

16 **Source: Exhibit MH-52, Page 19**

17
 18 Under the MH15 rate plan, Manitoba Hydro never reaches parity or 1.0x wherein it has
 19 sufficient EBITDA to meet all of its cash obligations.
 20

21 At page 54 of Exhibit MH-64, Manitoba Hydro also presented this illustrative ratio under
 22 the MH16 Update with Interim rate path wherein by 2019/20 Manitoba Hydro is

1 essentially cash flow break-even and by later in the forecast has an adequate cushion
 2 which can be used to deleverage and de-risk unsustainable debt loads.

3
 4 **Figure 5.14**

(In Millions of Dollars)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
MH16 Update with Interim:										
EBITDA (Numerator)	1439	1676	1795	2068	2307	2308	2384	2495	2435	2508
Interest	936	982	1041	1121	1145	1138	1148	1125	1089	1060
Capital and Other Cash Needs	763	772	740	769	766	742	723	783	799	822
Cash Burdens (Denominator)	1700	1754	1782	1890	1911	1880	1871	1908	1888	1882
EBITDA / Ongoing Cash Burdens Equity Ratio	0.85 x 15%	0.96 x 14%	1.01 x 14%	1.09 x 15%	1.21 x 17%	1.23 x 17%	1.27 x 19%	1.31 x 21%	1.29 x 23%	1.33 x 25%
At MH15 Rates:										
EBITDA / Ongoing Cash Burdens Equity Ratio	0.85 x 15%	0.91 x 14%	0.91 x 13%	0.95 x 13%	1.01 x 13%	0.96 x 12%	0.94 x 12%	0.94 x 11%	0.92 x 10%	0.95 x 10%

5
 6 **Source: Exhibit MH-64, Page 54**

7
 8 **5.7 Past Leverage Levels of No Current Relevance**

9 Mr. Osler provided testimony attempting to put Manitoba Hydro's current circumstance
 10 in historical context. A large basis of the comparison was to the post-Limestone period
 11 (early 1990s onward) wherein Manitoba Hydro emerged from a period of major
 12 investment with an extremely low debt:equity ratio. Mr. Osler explains how this made
 13 sense in customary regulatory practice and should serve as a guide for the patient
 14 restoration of Manitoba Hydro's financial health in the current period.

15
 16 The circumstances of the Limestone-era are vastly different from the scale of issues
 17 facing Manitoba Hydro at present. Mr. McCallum outlined these at Transcript Pages 184
 18 to 186:

19
 20 *"After Limestone, we had \$4 1/2 billion of debt. That was about ten thousand*
 21 *dollars (\$10,000) of debt per customer. Today we have thirty- five thousand*
 22 *dollars (\$35,000) of debt per customer. We're heading to about forty-two*
 23 *thousand dollars (\$42,000) of debt per customer, four (4) times higher...*

24
 25 *In the ten (10) years after Limestone, we had net income of almost \$1 billion.*
 26 *Those are in then dollars, not even adjusting for inflation over twenty (20) years.*
 27 *That was earning -- earned operating a business that averaged about \$5 billion*

1 *of net plant in service over that decade. It was earned operating a business in a*
2 *significantly higher rate interest environment, three (3) to four (4) times higher,*
3 *and in a decade where we enjoyed above-average water conditions in two (2) of*
4 *the ten (10) years.*

5
6 *Let's turn to the 3.95 percent plan... our business is five (5) times larger. Our*
7 *relative debt levels are four (4) times greater... instead of making the... 1 billion*
8 *we did in the decade after Limestone, instead, if things go well, lose 400 million.*
9 *The suggestion we were in the same place as we have been before is*
10 *preposterous."*

11
12 The addition of the Limestone generating station, for \$1.43 billion (Manitoba Hydro's
13 Written Rebuttal Evidence on the MGF Report, Exhibit 117, Appendix A), reflected
14 roughly a 40% increase⁶ to the plant in service of the Corporation. The additions of
15 Keeyask, Bipole III and MMTP reflect a \$14.2 billion combined investment (Appendix 3.1
16 of the Application, page 51) which more than doubles the in service asset base of today.

17
18 In summary, the scale of assets and debt being added to Manitoba Hydro relative to its
19 pre-existing operations is entirely different. In every respect, the financial impact of
20 Manitoba Hydro's development plan dwarfs that of Limestone and comes on the heels
21 of a prolonged period of insufficient rates. Therefore the financial plan necessary to
22 absorb this growth in the business must be dramatically different.

⁶ Transcript page 185 notes an average \$5 billion net plant in service in the decade after Limestone.

6 FINANCIAL TARGETS AND THE ROLE OF RESERVES IN MANAGING FINANCIAL HEALTH

6.1 Overview of Financial Targets

As discussed in Tab 4 of the Application, Manitoba Hydro has revised its primary financial targets following internal review and an external review by KPMG in May, 2015. These targets are described below.

6.1.1 Equity Ratio:

The debt:equity ratio measures the relationship of long-term and short-term debt to equity. Effectively, Manitoba Hydro's calculation of its debt:equity ratio compares net debt to total capital (calculated as net debt plus equity). This ratio identifies the capital structure of the Corporation and assesses the overall financial risk to Manitoba Hydro.

As indicated in Appendix 4.1 of the Application on page 16, the capital structure as measured through the debt:equity (or debt to capital) ratio is universally accepted by the capital markets and financial and investment industry as one of the primary measures of financial strength.

Manitoba Hydro's objective is to maintain the appropriate balance between debt and equity. An adequate level of retained earnings is required to withstand the financial impacts of risks faced by Manitoba Hydro, including but not limited to drought and water flow, and is an important consideration in credit ratings and financing costs.

Manitoba Hydro's current debt:equity target of 75/25 is a reasonable long-term target. KPMG did note that a target of 70/30 would provide additional financial strength to address the utility's unique financial challenges and risks and recommended that the debt:equity ratio should fall within the range of 75/25 to 70/30. Following an internal review in 2016, the Manitoba Hydro Electric Board and senior management team determined that the target should remain at 75/25, and that the Corporation should target attainment of the 25% equity in a period not longer than 10 years in order to reduce the financial risks to the Corporation (Tab 4, page 7).

6.1.2 Interest Coverage Ratio:

The Interest Coverage Ratio assesses the degree to which Manitoba Hydro can meet its interest obligations with the operating income generated annually. An EBITDA-based metric includes the cash flows associated with the accounting of depreciation and

1 amortization expense in the numerator of the interest coverage calculation. As these
2 cash flows can be used to make interest payments, this indicator uses an approach for
3 calculating coverage that is more cash-flow based than that using EBIT.

4
5 EBITDA, however, is not an exact measure of cash flow since it does not incorporate
6 capital expenditure requirements or working capital adjustments. Nevertheless, it is
7 closer to a cash-flow metric than EBIT.

8
9 KPMG recommended a minimum EBITDA interest coverage ratio at a target level of 1.8
10 or greater. Previously, Manitoba Hydro had maintained a minimum target for the EBIT
11 interest coverage ratio of 1.2. The KPMG recommendation for an EBITDA interest
12 coverage ratio with a minimum target of 1.8 was adopted by the Manitoba Hydro
13 Board in December, 2015.

14 15 **6.1.3 Capital Coverage Ratio:**

16 The Capital Coverage Ratio measures Manitoba Hydro's ability to fund its sustaining
17 capital expenditure (e.g. ongoing maintenance and replacement capital expenditure
18 "capex"), excluding Major New Generation and Transmission, from its current cash flow
19 from operations. KPMG found that the current target of 1.2 or greater for the capital
20 coverage ratio is reasonable, and the Manitoba Hydro-Electric Board endorsed the ratio
21 and target in December 2015. An inherent limitation of this ratio is that it does not
22 reflect the financial challenges associated with major expansion programs. Hence it
23 may be misunderstood or misinterpreted by stakeholders.

24 25 **6.2 Financial Targets are a Measure of Financial Health**

26 Achieving and maintaining financial targets is important for the financial health of the
27 utility, supporting the interest of domestic ratepayers who ultimately bear the cost of
28 operating, maintaining and renewing the system. Given the credit support provided to
29 Manitoba Hydro by the Province of Manitoba, it is also fundamental that Manitoba
30 Hydro be self-supporting in the eyes of credit rating agencies and lenders to avoid the
31 unacceptable risk of having the Province's cost of borrowing impaired and implicitly or
32 explicitly having to subsidize the continued financial viability of the electricity system.
33 Presently, Manitoba Hydro enjoys a cost of financing that is significantly lower than
34 what it could obtain without the Provincial Guarantee, while the quantum of borrowing
35 required would likely be unattainable given the Corporation's current credit profile.

1
2 The equity ratio along with an EBITDA coverage ratio and a Capital Coverage ratio are
3 conventional measures of financial health and credit-worthiness. Positive cash flow
4 from operations inclusive of servicing debt is also relevant to a determination of self-
5 supporting status.

6
7 As indicated in the response to PUB/MH I-42, Manitoba Hydro's financial targets are set
8 in the context of being a government-owned entity with a modified cost of service rate
9 regime. As such, targets are set based on a minimum level of financial strength that
10 reasonably minimizes the risk of any contagion impact of the Corporation's financial
11 profile on the credit rating and/or borrowing costs of the Province of Manitoba as well
12 as ensuring Manitoba Hydro has the wherewithal to absorb adverse conditions such as
13 below average water conditions or rising interest rates, or event risks such as asset
14 failures, without having to look to ratepayers for emergency relief.

15
16 Such wherewithal stems from appropriate levels of income, cash flow and reserves.
17 Manitoba Hydro's equity position can only be enhanced through net income and, as
18 such, building an adequate equity position over a reasonable planning horizon. This is
19 particularly critical in the early years of the current financial plan where the capacity to
20 absorb risk is low due to current deficiencies in income and equity levels along with an
21 unavoidable escalation in debt and operating costs as two major new projects are
22 completed and commissioned. Attainment and maintenance of a 75/25 debt equity
23 ratio also positions Manitoba Hydro to manage its unique set of risks including
24 hydrology risk, export market risk, interest rate risk and its limited financial flexibility.

25 26 **6.3 There is No Need to Adjust Targets for Purposes of Ratemaking**

27 At Transcript Page 4938, Mr. Colaiacovo of Morrison Park Advisors ("MPA") states:

28
29 *"And I would suggest that having a rule of some kind would help guide*
30 *rate-making and allow you to make the kind of determination that I think*
31 *you would like me to offer."*

32
33 Manitoba Hydro has established financial targets for the purposes of guiding, managing
34 and reporting on its financial health. The financial targets used by Manitoba Hydro
35 were established with the assistance of recommendations from two leading, globally

1 recognized experts (RBC Dominion Securities in 1995, KPMG in 2015). MPA asserts that
2 some new vaguely defined “rule” is now required to address an unsupported argument
3 of deficiency in Manitoba Hydro’s current practices.
4

5 The PUB has acknowledged the importance of Manitoba Hydro having a sound plan to
6 return to financial strength, and endorsed the 75/25 debt:equity ratio. For example, in
7 Order 101/04, the PUB provided the following comments on Manitoba’s Hydro’s debt
8 to equity financial target:
9

10 *“Achieving a debt:equity ratio of 75:25 would provide increased rate*
11 *stability benefits, and hold down financial charges. The 75:25 benchmark*
12 *represents a modest target, one comparable with the current debt:equity*
13 *ratios of similar Crown hydroelectric utilities in other Canadian provinces*
14 *(BC Hydro and Hydro-Quebec). In summary, meeting this target within a*
15 *reasonable period of time would reduce long-term pressure on domestic*
16 *electricity rates, better assure bondholders and thus constrain financial*
17 *charges and provide a hedge against a future drought” (Page 31 of PUB*
18 *Order 101/04).*
19

20 The PUB also commented on the importance of Manitoba Hydro’s financial strength in
21 Order 116/08:
22

23 *“It is the Board’s [PUB] understanding that rating agencies look prominently*
24 *at MH’s financial strength in assessing the credit rating of the Province. A*
25 *weakening of the financial strength of MH would not be viewed favourably*
26 *by those credit agencies and may have implications impacting the credit*
27 *rating of the Province, making provincial borrowing more expensive. Such a*
28 *development would not be in the public interest” (Page 130 of Order*
29 *116/08).*
30

31 The PUB reiterated the importance of Manitoba Hydro’s Financial Strength in Order
32 43/13:
33

34 *“The Board is concerned that, by moving towards a 90:10 debt-to-equity*
35 *ratio by the end of the decade, there will be an insufficient retained earnings*

1 *reserve to deal with droughts and other risks such as infrastructure failure*
2 *or rising interest rates....*

3
4 *The Board notes that Manitoba Hydro shares the benefit of the flow-*
5 *through credit rating of the Province, which affords it preferential interest*
6 *rates on its debt and access to funds to meet its major capital spending*
7 *program. However, as its debt grows, there is a potential for Manitoba*
8 *Hydro's financial condition to affect the credit rating of the Province. It is*
9 *important that Manitoba Hydro remains a financially strong and viable*
10 *organization” (Page 23 of Order 43/13).*

11 12 **6.4 The Role of Reserves in Managing Manitoba Hydro's Risks**

13 At numerous points in the evidence, Manitoba Hydro as well as a number of intervenors
14 acknowledged that reserves are essential to the corporation and in fact required by
15 Section 40 of the *Manitoba Hydro Act*. Mr. Bowman acknowledged that operating with
16 little or no equity is not a good idea and that it is clear that Manitoba Hydro requires
17 substantial reserves:

18
19 *“MR. MATTHEW GHIKAS: Right. Now, in terms of your reference to the many*
20 *Crown utilities, both electrical and other, that have operated for long periods*
21 *with little or no equity, first of all, irrespective of whether there have been other*
22 *entities operating with little or no equity over time, doesn't necessarily mean*
23 *that's a good idea when it comes to Manitoba Hydro, does it?*

24
25 *MR. PATRICK BOWMAN: I'm not suggesting this statement is -- is setting out that*
26 *it's a good idea. I'm suggesting this statement is setting out the fact that -- that*
27 *it's possible. And, as matter of fact, the very next line says **it is clear Manitoba***
28 ***Hydro requires relatively substantial reserves”** (Emphasis Added) (Transcript*
29 *Page 6279).*

30
31 Mr. Coloaiacovo of MPA stated:

32
33 *“So, you know, you always want to make sure that in a challenging scenario, you*
34 *have enough reserves” (Transcript Page 4942)*

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And later

“There’s no question that Manitoba Hydro requires reserves. The only thing that we’re debating is what the size of those reserves should be” (Transcript Page 5138).

As Manitoba Hydro’s cash deficit evidence has amply demonstrated, current rates are not adequately funding maintaining operations and reinvesting in the utility (see Section 2.1.2 for further information regarding cash deficits).

MPA has asserted that reserves are important and that the 3.95% rate path appears *“reasonably robust”*. Manitoba Hydro notes that the trajectory of net income under the 3.95% rate path forecast over the next 10 years is worse than the net income actually earned by Manitoba Hydro over the prior 10 years. As such Manitoba Hydro sought to at least have MPA defend the conclusion that historic cash flows and income levels created or maintained sufficient financial reserves as a precursor to evaluating the sufficiency of the forward projection. At MH/Coalition (MPA) – 16, MPA responds:

“MPA does not assert that historic cash flows and income levels created “sufficient” financial reserves, merely that any reserves (or “equity”) that are in place were the result of ratepayer contributions”.

As demonstrated at slide 66 of Manitoba Hydro’s Policy Panel Presentation, Exhibit MH-64, Manitoba Hydro’s net income has been dropping precipitously in the last 10 years notwithstanding above average water conditions, declining interest rates and a growing asset base. This is evidence that no contribution to reserves is being made in rates charged to current ratepayers. Moreover, the analysis Manitoba Hydro provided in response to new evidence introduced in the hearing by MPA reinforces the erosion of reserves over the last 5 years. Ignoring the impacts of the major capital projects, rate inadequacy has led to debt increasing 20% while equity decreased 10% resulting in a 5.4% decline in Manitoba Hydro’s equity to debt ratio just as a result of core operations.

1

Figure 6.1 Deterioration in Capital Structure

	Net Equity	Net Debt	Equity Ratio	Debt Ratio	Accounting Standard
2017 Capital Structure per MPA Adjusted Analysis	\$3,289	\$8,961	26.8%	73.2%	Adjusted
Conawapa Construction Work in Progress	\$0	(\$379)			
Bipole III Deferred Revenues ¹	(\$196)	\$196			
Wind Farm Loan Repayment ²	\$0	\$250			
Bipole III Interest Capitalized ³	(\$55)	\$55			
Export Revenues Attributable to Above Average Water ³	(\$219)	\$219			
Non-Recurring Gain ⁴	(\$20)	\$20			
Adjustments	(\$490)	\$361			
2017 Capital Structure per MPA Adjusted for Above (A)	\$2,799	\$9,322	23.1%	76.9%	Adjusted
2012 Capital Structure - excluding Bipole III, Conawapa and Keeyask (B)	\$3,102	\$7,788	28.5%	71.5%	CGAAP
Deterioration in Capital Structure (A - B)	(\$303)	\$1,535	-5.4%	5.4%	
Change from 2012	-10%	20%			

¹ The Manitoba Hydro-Electric Board 65th Annual Report, Note 26, p.84

² Appendix 6.1, The Manitoba Hydro-Electric Board 64th Annual Report, Note 21, p.83

³ Manitoba Hydro Exhibit #64, slide 44

⁴ The Manitoba Hydro-Electric Board 65th Annual Report, Note 26, p.84

2

3

Source: Exhibit MH-135, page 6

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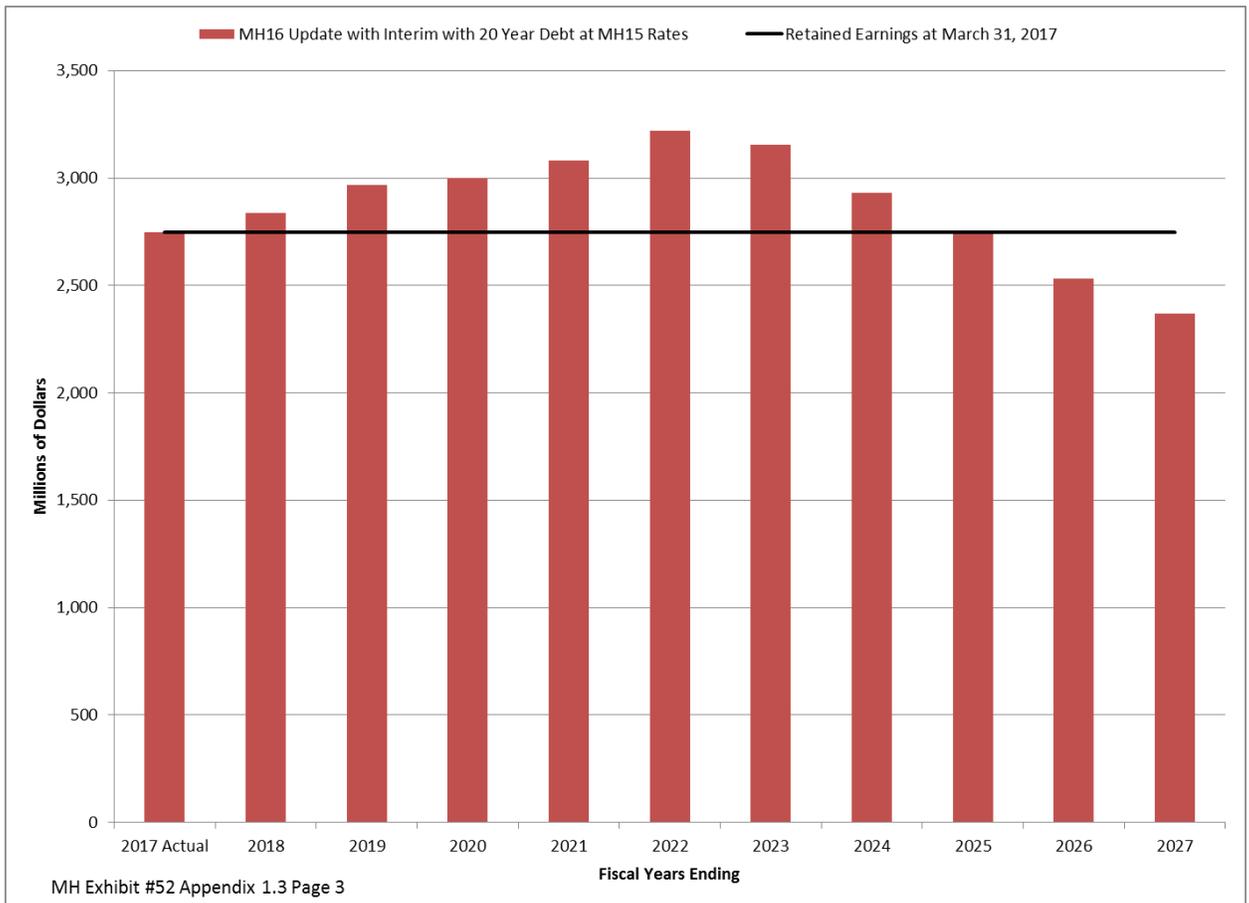
12

13

Looking forward, the following **Figure 6.2** compares Manitoba Hydro's retained earnings from the MH16 Update with Interim scenario which assumed 20 year debt and the previous plan's 3.95% rate increases (MH Exhibit #52, Appendix 1.3, page 3) to the retained earnings as at March 31, 2017. **Figure 6.2** shows that customer revenues are just sufficient to make modest annual contributions to retained earnings until 2022, but that following Keeyask in-service, financial losses deplete retained earnings to a level below the current \$2.7 billion at March 31, 2017.

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Figure 6.2 Manitoba Hydro Retained Earnings at 3.95% Rate Increases



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Depletion of retained earnings is evidence customer revenues are not sufficient to cover the operating and carrying costs of assets. Manitoba Hydro must borrow to cover these costs on top of the increased leverage resulting from the investments in Bipole III and Keeyask.

At MH/Coalition (MPA)–16(c), Manitoba Hydro asked how MPA concluded that the 3.95% rate plan effectively contributes to financial reserves to manage unforeseen risks or rate stabilization and received the following response:

“MPA does not make that conclusion....”

Rates must be set inclusive of proper reserve contributions. This comes in the form of a rate path that is expected to generate positive net income in normal water flow years.

1 At Transcript page 4941, Mr. Colaiacovo appears to agree that the forecast ought to
2 include the assumption of progress on financial targets in normal water years:

3
4 *“And if the rates are high enough, well, then, that helps guide you to a -- a*
5 *decision that those rates are sufficient. Then, you would also ask yourself, if*
6 *water was at more typical levels over that period, over that five (5) or seven (7)*
7 *year period, what would be the effect? Would it be -- would we be making*
8 *progress on our financial targets more broadly? Would be -- we be repaying*
9 *capital?”*

10
11 That reserves come in the form of ongoing expectations of net income (and cash flow) is
12 critical given, as demonstrated above and confirmed by Intervener witnesses, retained
13 earnings is non-cash and powerless to abate debt growth in the face of financial
14 distress, poor hydrology or forecast error.

15
16 During NFAT, MPA (then as IEC to the PUB) made this statement at page 38, lines 15-18
17 of its January 2014 report (included as Tab 8 of Manitoba Hydro’s Book of Documents
18 #1, Exhibit MH-116-1):

19
20 *“Retained earnings are driven in part by the rates approved by the PUB for*
21 *electricity in Manitoba, which nominally should include a “return on equity”*
22 *component in order to ensure that Manitoba Hydro actual (sic) earns net income*
23 *that can be retained.”*

24
25 Likewise at NFAT, in the response to PUB/MPA 1-030 (a) (included as Tab 3 of Exhibit
26 MH-116-1) as follows:

27
28 *“Since Manitoba Hydro’s cash flows fluctuate dramatically with hydrology and*
29 *export prices, and **Manitoba Hydro’s target equity ratio is a comparatively thin***
30 ***25%**, the use of an equity risk premium as low as 4.5% is notable. On the other*
31 *hand, Manitoba Hydro is governed by “cost of service” legislation, which*
32 *nominally requires Manitoba ratepayers to bear all of Manitoba Hydro’s costs,*
33 *and Manitoba Hydro benefits from a Province of Manitoba guarantee of*
34 *substantially all of its debt. Assuming the legislation is accepted at face value and*
35 *domestic rates could rise to whatever level were required at any given time to*

1 *maintain Manitoba Hydro solvency, under any circumstances, then a legitimate*
2 *question is whether an “equity risk premium” is applicable? On its face, the*
3 *legislation coupled with the provincial debt guarantee suggests that there is no*
4 *risk to equity, and hence the premium should be 0%. **In reality, however, rates***
5 ***do not rise and fall annually, but are smoothed over time. This suggests that***
6 ***equity returns should be built into rate structures to provide a cushion for***
7 ***inevitable swings in cash flow that derive from non-controllable events, such as***
8 ***hydrology and export prices. Moreover, the possibility of prolonged financial***
9 ***distress also suggests that equity premiums (and a healthy equity ratio target)***
10 ***are required.”** (Emphasis Added))*

11
12 Manitoba Hydro was perplexed by the new assertion MPA makes in these proceedings,
13 as an Intervener expert witness, that now reserves ought to only be maintained for
14 hydrology risks (Transcript Page 4911). MPA takes the position that it is not appropriate
15 to address interest rate risk or export price risk through reserves on the basis that
16 because interest rates change slowly, Manitoba Hydro does not have large quantum of
17 debt subject to interest rate risk in any one period, and that export prices cannot be
18 forecast in the longer term due to unidentifiable technology change. As a result, MPA
19 concludes (Transcript Page 4913) that the financial impacts of these risks cannot be
20 smoothed over the longer term. Of interest, at Transcript Page 5011 Mr. Colaiacovo
21 confirms that export prices and interest rates are “*noncontrollable*” which would be
22 precisely the argument he makes at NFAT (per above quote) as necessitating a rate
23 structure that contributes to reserves such that rates can be “*smoothed over time*”.

24
25 In Manitoba Hydro’s view, neither the current rate increase request nor the
26 Corporation’s longer term financial plan are intended to shield customers from
27 legitimate and enduring changes in cost drivers over the long term by absorbing them
28 into reserves. Manitoba Hydro’s objective in this Application has been quite the
29 opposite – the request to advance rate increases from 3.95% to 7.90% is specifically
30 intended to address the reductions in revenues attributable to reduced expectations for
31 domestic load growth and export prices. As Mr. Shepherd indicated “...[Manitoba
32 Hydro] missed a great opportunity to add to our reserves and avoid more debt by taking
33 advantage of many, many years of excellent water conditions which should have been
34 used to boost net income.” (Transcript Page 243).

1 MPA's conclusion that "...the amount of [Manitoba Hydro's] debt that is exposed to
2 interest rates in any one (1) year is a relatively small portion; notwithstanding the fact
3 that they're in the midst of issuing a lot of debt." (Transcript Page 4911) is incorrect.
4 Slide 62 of Exhibit MH-68 and pages 12-13 of Manitoba Hydro's Written Rebuttal
5 Evidence (Exhibit MH-52) indicate that assuming adoption of a 7.9% rate path, between
6 2018 and 2022, Manitoba Hydro is projected to borrow \$13.5 billion This means that a
7 moderate 100 basis point (1%) increase in interest rates over that forecast in MH16
8 Update with Interim will result in an increase to finance charges of \$130 million annually
9 (not including the compounding effects over multiple years) or an equivalent one-time
10 rate increase of 8%. Under a 3.95% rate path, the amount of new borrowing and
11 refinancing risk exposure over the first five years of the forecast increases to over \$20
12 billion. In Manitoba Hydro's respectful submission, \$13 billion of new borrowing and
13 refinancing over the next five years is not a "small portion" of Manitoba Hydro's net
14 debt (forecast to end 2017/18 at \$18.5 billion per Appendix 3.8) and should be
15 considered in addition to the risk of drought in setting an appropriate level of reserves.
16

17 Manitoba Hydro noted with great interest MPA's disagreement in this proceeding with
18 Manitoba Hydro's view that when managing distress caused by events such as drought,
19 the critical issue is the magnitude of the outstanding debt on the balance sheet, not the
20 size of the retained earnings:
21

22 *MR. MATTHEW GHIKAS: Okay. Now, I'd suggest to you that when it comes to*
23 *managing distress that comes with an event such as drought, the critical issue is*
24 *the magnitude of the outstanding debt on the balance sheet, not the size of the*
25 *retained earnings.*

26 *MR. PELINO COLAIACOVO: I don't think I would necessarily agree with you. I*
27 ***don't think magnitude of debt in isolation has any relevance.** Debt in relation to*
28 *assets so, you know, if your assets are highly leveraged it wouldn't matter but if*
29 *you have \$50 billion of assets and \$25 billion of debt is 25 billion an important*
30 *number? I don't actually think so. So the magnitude of the debt in isolation is just*
31 *a fact. (Emphasis Added) (Transcript Page 4991)*
32

33 MPA's evidence in this regard once again directly contradicts its response provided to its
34 current client (Consumers Association of Canada) during the NFAT proceeding when,
35 acting in the capacity of PUB Independent Expert Consultant it stated:

1
2 ***“The critical issue is the magnitude of outstanding debt on the balance sheet,***
3 ***not the size of the retained earnings. In the event of a persistent revenue***
4 ***shortfall caused by prolonged drought, for example, interest charges related to a***
5 ***large outstanding debt represent a real call on cash flow. A large pool of retained***
6 ***earnings in this environment would be beneficial in that the company balance***
7 ***sheet potentially could sustain a series of annual losses, but balance sheet***
8 ***retained earnings bear little relationship to the availability of cash resources”***
9 (NFAT IR CAC/MPA-13 reviewed during cross-examination by Mr. Ghikas,
10 (Emphasis Added) (Transcript Page 4992).

11
12 Upon being presented with this contradictory statement during cross-examination by
13 Mr. Ghikas (Transcript Page 4992), while no explanation was provided for this dramatic
14 about-face, MPA did acknowledge that retained earnings are not cash and that cash
15 flow is the issue:

16
17 *“The magnitude of the outstanding debt tells you how much interest, as it says*
18 *here, the interest charge is related to the large outstanding debt represent a real*
19 *call on cash flow because cash flow is the issue. And so if drought causes your*
20 *cash flow to fall, you have a problem that you have to manage”* (Transcript Page
21 4993).

22
23 Presumably the “[cash flow] problem that you have to manage” is an issue regardless of
24 whether it is caused by drought, interest rates increasing, export prices being non-
25 responsive or capital costs going up. This position is consistent with the evidence of
26 Manitoba Hydro’s President, Mr. Kelvin Shepherd, regarding the role of reserves relative
27 to the need for cash flow:

28
29 *“Equity in and of itself does nothing for you. This is particularly the case when*
30 *almost all of our equities is derived from cumulative earnings generated more*
31 *than ten (10) years ago. Even more recently, the entirety of the growth in our*
32 *equity has been a byproduct of unexpected profits owing to near record water*
33 *conditions over the last several years.*

1 *Equity is not cash. This is essential to understand. Equity is not a store of cash*
2 *that we can use to mitigate rate increases when bad things happen. The only*
3 *cushion to absorb unforeseen events and risk without having to raise rates even*
4 *more and/or borrow yet more money is having rates at sufficient levels where*
5 *your generating income and cash flow. And as we make clear, the old plan with*
6 *its 3.95 percent rate path comes nowhere near close to doing this for us. Without*
7 *this cushion when adverse events occur, the only choices available are to increase*
8 *rates, potentially a lot, or borrow more money. We should not and cannot as a*
9 *planning matter knowingly put ourselves in that position” (Transcript Page 240).*

10
11 Depleting Manitoba Hydro’s reserves over a period of years under average water flow
12 conditions and expected assumptions in the previous 3.95% rate plan as shown in **Figure**
13 **6.2** is neither sustainable nor prudent. As noted by Mr. McCallum,

14
15 *“...as a planning matter, we don't believe you can target nil or breakeven net*
16 *income for a businesses as large, complex, asset intensive, volatile, and indebted*
17 *as ours. We have to plan, inclusive of in our rate strategy, for a cushion that*
18 *allows for a margin of error and to create reserves in the form of paying down*
19 *debt when things go right” (Transcript Page 154).*

20
21 It is interesting to note that despite Intervenors acknowledgement of the need to
22 maintain adequate reserves, none presented evidence of a plan which in anyway served
23 to contribute to and rebuild reserves.

24
25 It is of critical importance to move off the rate path of 3.95% to build reserves annually.
26 As Ms. Carriere correctly observed *“...there is simply no additional capacity for the 3.95*
27 *percent rate plan to absorb any further increases in costs or deterioration in financial*
28 *position [and]...the level of debt has grown out of proportion with our assets and the*
29 *current level of revenues” (Transcript Page 720).* It should be noted that in the event
30 Manitoba Hydro’s forecasts of load and export revenues prove conservative and actual
31 results turn out more favourably, customer contributions to reserves do not *“leak out”*
32 as dividends as they would in a typical investor-owned utility. Customer contributions
33 stay within Manitoba Hydro and under cost of service regulation, the PUB has an
34 opportunity in future proceedings to adjust customer rates accordingly.

1 **6.5 Debt Markets Care about Debt:Equity Ratio**

2 On Pages 34 to 35 of MPA’s Evidence filed on behalf of the Consumer’s Coalition, Exhibit
3 CC-17, MPA suggested that analysts serving the capital markets appear to place a higher
4 priority on cash flow metrics and the ability to adjust rates as required to match
5 operational requirements. It noted that, *“Certainly, the capital structure of a utility is*
6 *important, and all analysts do recognize that, but few if any appear to make capital*
7 *structure a centerpiece of their analysis in the way Manitoba Hydro does.”*

8
9 The suggestion advanced by MPA that debt markets do not prioritize the strength of the
10 equity ratio is not correct. Equity ratio is a good proxy for overall debt levels and
11 investors care very much about that. Markets and rating agencies understand the
12 intrinsic relationship between equity ratio and cash flow and all of the other financial
13 metrics that analysts take into consideration.

14
15 Nonetheless, Section 2.2 of Manitoba Hydro’s Application along with slide 46 of Exhibit
16 MH-64 emphasize just how concerned the Corporation is with the level of forecasted
17 cash flow and its ability to meet critical ongoing business requirements.

18
19 Manitoba Hydro presented a cash flow analysis *“Cash Flow from Operations to Capital*
20 *Expenditures”* in Section 2.2 of the Application to better represent its capacity to meet
21 its core obligations under different rate paths. Without the proposed rate increases, this
22 metric demonstrates how cash flows will not be sufficient to cover the projected
23 increase to interest payments associated with the unprecedented investment in major
24 projects and the unavoidable capital requirements related to system renewal and
25 expansion. This is consistent with what MPA suggests is a higher priority for analysts
26 serving the capital markets.

27
28 In the August 2017 Supplementary Update to Manitoba Hydro’s Financial Target Review,
29 KPMG commented that, *“We note that Manitoba Hydro has developed an additional*
30 *metric that examines adjusted cash flow to adjusted capital expenditures. This metric is*
31 *intended to reflect overall cash flow impacts and related challenges in a more complete*
32 *way during periods of major capital investment.”* (Appendix 4.5 of the Application, page
33 11)

1 Manitoba Hydro's rate proposal was established to provide increased cash flow to meet
2 two key objectives: (i) avoid deficit funding the ongoing business over the next five years
3 and (ii) partially abate the increase in debt as the major capital projects are concluding
4 and then begin retiring debt following Keeyask's in-service so as to mitigate future rate
5 increases that may be required should interest rates rise. As such, Manitoba Hydro's
6 plan to restore financial strength is centered on generating positive cash flow and
7 managing the absolute level of debt.

8 9 **6.6 The Importance of Manitoba Hydro Being Viewed as Self-Supporting**

10 The key to preserving the credit of the province is for Manitoba Hydro to be viewed as
11 self-supporting. MPA notes agreement with this concept and the importance of
12 messaging to the markets:

13
14 *"... I do think that managing the message to the capital markets is,*
15 *indeed, important and in their application, Manitoba Hydro has talked*
16 *about credit quality and the impact on credit ratings and the treatment of*
17 *Manitoba Hydro in the province of Manitoba by the markets. And the very*
18 *fact that Manitoba Hydro has made this application and has requested a*
19 *series of 7.9 percent increases is in itself a message to the markets; a*
20 *partial message, an initial message but nonetheless a message. And so,*
21 *the Board's response to that application is also a message and I think the*
22 *crafting of those messages is-- is important and has to be taken into*
23 *account"* (Transcript Pages 4850 to 4851).

24
25 Credit rating agencies have indicated that they will continue to monitor the progress on
26 the capital projects, rate increases, Manitoba Hydro's financial metrics and the financial
27 outlook. Credit rating agencies monitor a variety of financial metrics as evidenced in this
28 quote from DBRS on page of its credit rating report on the Manitoba Hydro-Electric
29 Board from November 26, 2015 (Appendix 4.4 of the Application):

30
31 *"The Utility has forecast leverage (81.0% as at March 31, 2015) to increase*
32 *to around 88% during this period of high capex. Additionally, due to the*
33 *significant lag before electricity rates fully reflect the cost of the ongoing*
34 *major projects, Manitoba Hydro has forecast weaker earnings, including*
35 *two years of negative net income, and significant free cash flow deficits for*

1 *the medium term in its 2015 Integrated Financial Forecast. This will result in*
2 *further pressure on the Utility's key financial metrics, which could be*
3 *exacerbated in the event of an adverse circumstance (i.e., severe drought)."*
4

5 MPA asserts at page 3 and 4 of Exhibit CC-17 that *"While the capital structure of a*
6 *prospective borrower like Manitoba Hydro is important, it appears to be a secondary*
7 *issue for the capital markets."* Yet in MPA's own evidence on page 33 MPA identifies
8 seven metrics tracked by S&P in assessing financial risk and identifies that the two
9 primary metrics are both associated with relative debt levels (not cash flow sufficiency
10 alone). This is discussed at Transcript Pages 5043 to 5044:

11
12 *"MR. MATTHEW GHIKAS: Now, you go on to line 21 there, where you say: "S&P*
13 *further defined seven (7) -- seven (7) metrics that it focuses on with respect to*
14 *cash flow. Note the first two (2) are the primary metrics, and the other five (5)*
15 *are secondary, the sheer number of which provides an illustration of the level of*
16 *focus on cash flow in S&P's typical financial risk analysis. These are..." And then*
17 *you set them out?*

18
19 *MR. PELINO COLAIACOVO: Yes.*

20
21 *MR. MATTHEW GHIKAS: So the first two (2) are the primary ones, right?*

22
23 *MR. PELINO COLAIACOVO: Yes.*

24
25 *MR. MATTHEW GHIKAS: And both of those metrics are a function of debt?*

26
27 *MR. PELINO COLAIACOVO: They are."*
28

29 Furthermore, notwithstanding MPA's assertions as to the primacy of cash flow, in their
30 own report (Exhibit CC-17) at page 101, credit rating agency Fitch states:

31
32 *"Fitch's analysis of financial metrics focuses principally on three core areas:*
33 *cash flow, liquidity and capital structure. **No single financial ratio stands***
34 ***apart from the rest.** On the contrary, the ratios are examined together,*

1 *providing a context for a utility's financial position that informs a complete*
2 *analysis."*

3
4 Finally, on page 103 of Exhibit CC-17, Fitch indicates:

5
6 *A rising equity ratio is viewed favorably, as it typically suggests **adequate***
7 ***cost recovery in rates, load growth and a component of internal funding of***
8 ***capital investments."***

9
10 Manitoba Hydro would observe that the 3.95% rate plan endorsed as "*reasonably*
11 *robust*" by MPA results in the exact opposite which is to say an equity ratio that
12 continue to decline following the in-service of Keeyask and thus, per Fitch, suggesting
13 continued inadequacy of cost recovery in rates.

14
15 The financial viability and creditworthiness of the Corporation is assessed by credit
16 rating agencies using debt:equity and interest coverage ratios as well as other relevant
17 financial and risk profile information. The debt:equity and interest coverage ratios
18 indicate the Corporation's ability to provide an "*equity cushion*" for possible losses and
19 the Corporation's ability to meet all of its financial obligations when due. These ratios
20 are used to assess whether the Corporation is financially self-supporting and capable of
21 absorbing a variety of financial risks.

22
23 The overall debt level is inextricably linked to the cash flow of the corporation. Interest
24 expense will be, by far, the largest cash flow burden on Manitoba Hydro's revenues.
25 The pursuit of a 25% equity ratio target within a 10-year planning horizon triangulates
26 with and reinforces generating the net income and cash flow sufficiency that lead to
27 creation of necessary reserves against unforeseen events and contribute to overall debt
28 reduction and support more stable and ultimately lower rates in the long-run than if the
29 3.95% rate path is pursued. Equity is not cash or a cash reserve that can be used to
30 mitigate rate increases to address adverse / unforeseen events. The equity ratio can also
31 be thought of as the Debt Ratio; the goal of the equity target is to get absolute levels of
32 debt down. The equity ratio is the best indicator of progress on rate adequacy,
33 sustainability and risk.

1 On cross-examination (Transcript Page 5010), MPA acknowledged his comment from
2 the NFAT hearing that rate smoothing: *"... suggests that equity returns should be built*
3 *into rate structures to provide a cushion for inevitable swings in cash flows that derive*
4 *from noncontrollable events such as hydrology and export prices. Moreover, the*
5 *possibility of prolonged financial distress also suggests that equity premiums and a*
6 *healthy equity ratio target are required."* In addition, on page 5006 of the transcript,
7 MPA states that: *"...in a company like Manitoba Hydro where revenues go up and down*
8 *with exports and with water, you can't actually predict these things perfectly in advance.*
9 *It makes sense to have some cushion, to have some equity in the Company and to adjust*
10 *your rates accordingly over time."*

11
12 In addition at Transcript Pages 5006 and 5007, MPA agreed that over time a healthy
13 business should generate sufficient cash flows to pay for its capital expenditures and
14 necessary interest and returns on equity associated with that capital, and that a sign
15 that a business has been retaining net income over time is that the equity portion of the
16 capital structure is increasing.

17
18 Manitoba Hydro agrees with MPA's comments that stipulate a healthy business should
19 generate sufficient cash flows to generate net income and that net income is effectively
20 a contribution to retained earnings.

21
22 MPA also discussed the importance of the Corporation's ability to maintain its self-
23 sufficiency during an extended drought. *"...So, if there's a drought and the drought*
24 *results in a Company having to issue lots more debt and rates do not go up in concert*
25 *with the drought conditions, then the debt will continue to accumulate and, eventually,*
26 *that will, you know, bring into question the Company's self-supporting status if it didn't*
27 *have enough reserves to begin with."* (Transcript Page 5137). Mr. Colaiacovo went on to
28 confirm that, consistent with his evidence during the NFAT, credit rating agencies which
29 currently do not include Manitoba Hydro debt as an obligation of the province of
30 Manitoba may reconsider that position, at least for a portion of Manitoba Hydro's debt,
31 which could have a significant implications for the government.

32
33 Manitoba Hydro believes this commentary underscores the value of an appropriate
34 level of equity for Manitoba Hydro as well as the Province of Manitoba.

1 **6.7 What a Supportive Regulatory Regime Really Means**

2 The Pre-Filed Testimony of Patrick Bowman, on behalf of the Manitoba Industrial
3 Power Users Group, Exhibit MIPUG-13, states on page 4-7,

4
5 *“... all indications are that there is no need to move to a 7.9%/year annual rate*
6 *increase regime to achieve a utility that is self-supporting. If anything, a key*
7 *conclusion... is the lack of need for a 7.9%/year rate increase today, but instead a*
8 *significant requirement to communicate regulatory support and a reliable*
9 *regulatory regime to lenders and credit rating agencies.”*

10
11 The argument that showing a reliable and predictable regulatory regime to rating
12 agencies and investors means maintaining a 3.95% rate increase regime is specious. A
13 regulatory regime which is not responsive to changing business conditions under the
14 guise of *“predictability”* would send the message to rating agencies and investors that
15 Manitoba Hydro’s financial health is not a high priority to the regulator. By not acting
16 to address obvious financial health issues, Manitoba Hydro risks making its financial
17 results and future rate increases even more unpredictable.

18
19 As indicated in the response to MIPUG/MH I-8, S&P’s criteria indicate that the
20 regulatory advantage assessment is MHEB’s largest business risk component, at 60%
21 weighting. The response quotes directly from S&P’s Criteria| Corporates| Utilities: Key
22 Credit Factors For the Regulated Utilities Industry (attached to the response) as follows:

23
24 *When assessing regulatory advantage, we first consider four pillars and*
25 *sub-factors that we believe are key for a utility to recover all its costs, on*
26 *time and in full, and earn a return on its capital employed:*

27
28 *Regulatory stability:*

- 29 • *Transparency of the key components of the rate setting and how these*
- 30 *are assessed*
- 31 • *Predictability that lowers uncertainty for the utility and its stakeholders*
- 32 • *Consistency in the regulatory framework over time*

33
34 *Tariff-setting procedures and design:*

- 35 • *Recoverability of all operating and capital costs in full*

- *Balance of the interests and concerns of all stakeholders affected*
- *Incentives that are achievable and contained*

Financial stability:

- *Timeliness of cost recovery to avoid cash flow volatility*
- *Flexibility to allow for recovery of unexpected costs if they arise*
- *Attractiveness of the framework to attract long-term capital*
- *Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments*

Regulatory independence and insulation:

- *Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers*
- *Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event*

Mr. Bowman focuses on just two pillars to the exclusion of the remaining two. Financial stability to permit the timely recovery of costs and capital support during construction to avoid cash flow pressure, and the ability to recover all costs cannot be ignored. In Manitoba Hydro's case where the utility has been operating with insufficient cash flow for cost recovery for several years, regulatory support through the approval of required rates is especially critical for the utility to be self-supporting.

It is a fallacy to suggest that credit rating agencies will take comfort in the utility being permitted a rate increase insufficient to meet its needs simply because it is "predictable". "Predictable" in this context must be understood to mean rate increases, the need for which have been communicated to ratepayers (as has been the case since May, 2017 when Manitoba Hydro first sought a 7.9% rate increase)⁷, approved by a regulator who has demonstrated the willingness to respond to events as they unfold, having been satisfied that the request is supported by the weight of the evidence.

⁷ See also the evidence of Dr. Yatchew at Transcript Page 4458

1 **7 MYTH OF THE 3.95% RATE PROMISE**

2 In the opening comments made by Consumers Coalition, Dr. Williams opined that,
3 “...[rate] promises that were made during the NFAT process have been broken by
4 Manitoba Hydro” (Transcript Page 81).

5
6 Similarly, Manitoba Keewatinowi Okimakanak (“MKO”) stated in its opening comments
7 at Transcript Page 115:

8
9 *The MKO First Nations took an active role in the in the NFAT hearings on*
10 *the understanding that if rate increases were necessary, they would be*
11 *looked at, they would be examined, they would be made appropriate. And*
12 *that's what was done, and the rate increases approved at that time were*
13 *substantially lower than was being done right now (Emphasis Added)*

14
15 In MKO’s cross-examination of Mr. Shepherd and Mr. McCallum, Manitoba Hydro legal
16 counsel clarified for the record that the Needs For And Alternatives To (“NFAT”) was not
17 a rate hearing and the NFAT did not seek approval of any rate increases. The
18 Chairperson affirmed the panel’s understanding of the purpose of the NFAT and
19 2015/16 & 2016/17 General Rate Application (“GRA”) as it related to rate increases:

20
21 *NFAT dealt with a number of issues that -- as I understand it, the 3.95*
22 *arose in the GRA that was following NFAT in the 2015 hearing, which was*
23 *a rate-setting hearing, and that one (1) did not relate to the other*
24 (Transcript Page 603).

25
26 In the presentation by Manitoba Hydro’s Revenue Requirement Panel (Exhibit MH-68),
27 Ms. Carriere addressed the myth of the NFAT and 2015/16 & 2016/17 GRA rate
28 promise:

29
30 *With respect to the rate projections for each of the development plans,*
31 *Manitoba Hydro was explicit in stating that the rate plans presented were*
32 *developed for the purposes of comparing development plans (Transcript*
33 Page 714);

1 *Manitoba Hydro emphatically stated that minimum rate increases were*
2 *necessary under all plans... (Transcript Page 715); and*

3
4 *Importantly, Manitoba Hydro cautioned the NFAT panel that the rate*
5 *projections set forth for each of the development plans were not*
6 *applicable for rate-setting purposes (Transcript Page 716).*

7
8 At no point has Manitoba Hydro ever made rate promises based on its long term
9 forecasts and has always been careful to distinguish between proposed and indicative
10 rate increase projections – a distinction which the Chairperson and panel have also been
11 acutely cognizant of through the course of this proceeding:

12
13 *Notwithstanding the indicative information in the IFFs, the only rate*
14 *approval requests by Manitoba Hydro before this Board at this time are*
15 *the confirmation of the two (2) existing interim 3.36 rate increases, as*
16 *well as the request to grant a 7.9 percent rate increase effective April 1st,*
17 *2018 from Manitoba Hydro's 2018/'19 fiscal year (Transcript Page 4120)*

18
19 In reality, forecasting is inherently unreliable. The further out the forecast goes, the less
20 likely it is to be accurate. This view is confirmed by Daymark Energy Advisors.

21
22 *...the use of [a forecast] is really in -- in understanding and preparing*
23 *yourself for change. Forecasts are inherently wrong (Transcript Page*
24 *3879).*

25
26 As noted in Section 3.4.3 Manitoba Hydro believes limited value should be ascribed to
27 forecasts a decade or more in the future. While the mid to latter years of forecasts
28 provide important information on directional trends of financial results, they should not
29 be relied upon for rate-setting purposes in specific test years. Forecasts are updated at
30 least annually and future rate decisions are better made based on forecasted
31 information available at that time.

32
33 Ms. Carriere reminded the panel that, at NFAT, Manitoba Hydro was careful to advise:
34

1 *“...that due to the uncertainty of forecasting, the rate increases are*
2 *indicative and are showing general directional trends in -- in rates. Actual*
3 *rate increases will vary from those, and will depend on many other factors*
4 *and not just the choice of development plan but due to changing water*
5 *flows, weather and costs to maintain the system and economic variables”*
6 (Transcript Page 715 to 716).

7
8 Historically in past orders, the Public Utilities Board of Manitoba (“PUB”) has
9 acknowledged and accepted that there is risk of forecast uncertainty and no “promise”
10 in the rate increases in Manitoba Hydro’s applications, and in certain circumstances,
11 even in the rate increases approved by the PUB. In January 2004 in the midst of one of
12 the lowest water flow conditions on record, Manitoba Hydro sought PUB approval for a
13 3% rate increase for April 1, 2004 and 2.5% for April 1, 2005 to recover reserves
14 following the extreme financial loss of 2003/04, on the heels of other significant events
15 such as the acquisitions of Centra Gas and Winnipeg Hydro and the special payment to
16 the province, all of which contributed to the depletion of reserves. Prior to the 2004
17 application, Manitoba Hydro had last appeared before the PUB in 1996, where average
18 increases of 1.5% effective April 1, 1996 and a further 1.3% effective April 1, 1997 were
19 approved, and in the 2002 Status Update Filing, where the corporation sought no rate
20 adjustment but the PUB directed rate reductions to the General Service Large and Small
21 classes.

22
23 In the Order arising from the 2004 filing, the PUB approved more than Manitoba Hydro
24 requested; 5% for August 1, 2004 and two conditional rate increases of 2.25% for April
25 1, 2005 and October 1, 2005. In granting the two conditional rate increases, the reasons
26 cited by the PUB at the time are remarkably familiar:

27
28 *In making the last two increases conditional, the Board provides a level of*
29 *protection for the long-term interests of ratepayers. At the same time,*
30 *these conditional increases provide reasonable assurance to MH that its*
31 *revenue base will be strengthened if the need is present. In particular,*
32 *conditional increases recognize the uncertainties present with respect to*
33 *forecasting export sales and net income. These uncertainties are related*
34 *to water levels and storage issues, export demand, pricing and other*
35 *related matters (Order 101/04, Pages 23 to 24).*

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Both conditional rate increases were subsequently approved as final.

The PUB further demonstrated an absence of rate “promises” in Orders 90/08 and 32/09. In Order 90/08, the PUB granted Manitoba Hydro a 5% rate increase for July 1, 2008 and a further 4% conditional rate increase for April 1, 2009. Manitoba Hydro had only sought 2.9% for each of 2008/09 and 2009/10; however, the PUB expressed a lack of confidence that the requested 2.9% were sufficient.

The PUB subsequently varied and approved a final rate increase in Order 32/09:

After a thorough and intense consideration of the evidence, and considerable contemplation, the Board will approve rate increases as of April 1, 2009 but will vary the level of the increases to 2.9%, to apply to all classes excepting for the Area and Roadway Lighting class.

...

By so doing, the Board balances MH’s evidence of recent improvements in the Utility’s financial situation and the pressures on its customers due to the recession with the Board’s ongoing concern respecting the many risks faced by MH (PUB Order 32/09, Page 1).

1 **8 PROJECTED REVENUES ARE DOWN**

2 **8.1 Overview**

3 Manitoba Hydro's projected revenues are down, primarily as a result of the combined
4 effect of a flattening of the domestic load forecast, export prices not rebounding as
5 previously expected and increased capital costs associated with the major projects,
6 Keeyask and Bipole 3.

- 7 • Manitoba load growth has not materialized as previously forecasted and the
8 Corporation is now faced with 10 years or more of no net load growth (Slide 38 of
9 Manitoba Hydro's Policy Panel Presentation, Exhibit MH-64);
- 10 • The forecast of export prices continues on a downward trend since MH15 (Slide 39
11 of Exhibit MH-64);
- 12 • The Keeyask control budget has increased by \$2.2B to \$8.7B and there has been a 21
13 month delay to the in-service date (Slide 40 of Exhibit MH-64).

14
15 The impacts of these risks have been somewhat offset by the following:

- 16 • Interest rates have remained at record low levels;
- 17 • Manitoba Hydro has enjoyed 14 consecutive years of greater than average system
18 inflows (Slide 33 of Exhibit MH-64).

19
20 To assess the reasonableness of Manitoba Hydro's revenue projections, the Public
21 Utilities Board of Manitoba ("PUB") retained Daymark Energy Advisors to review the
22 corporation's Load Forecast, Export Price Forecast and Export Revenue Forecast.
23 Daymark was provided unfettered access to Manitoba Hydro's information, including
24 commercially sensitive information not available on the public record. In addition, Dr.
25 Adonis Yatchew reviewed the price elasticity values incorporated in Manitoba Hydro's
26 load forecast. While areas for enhancement were identified, no issues were reported
27 that materially impacted forecast results or revenue projections.

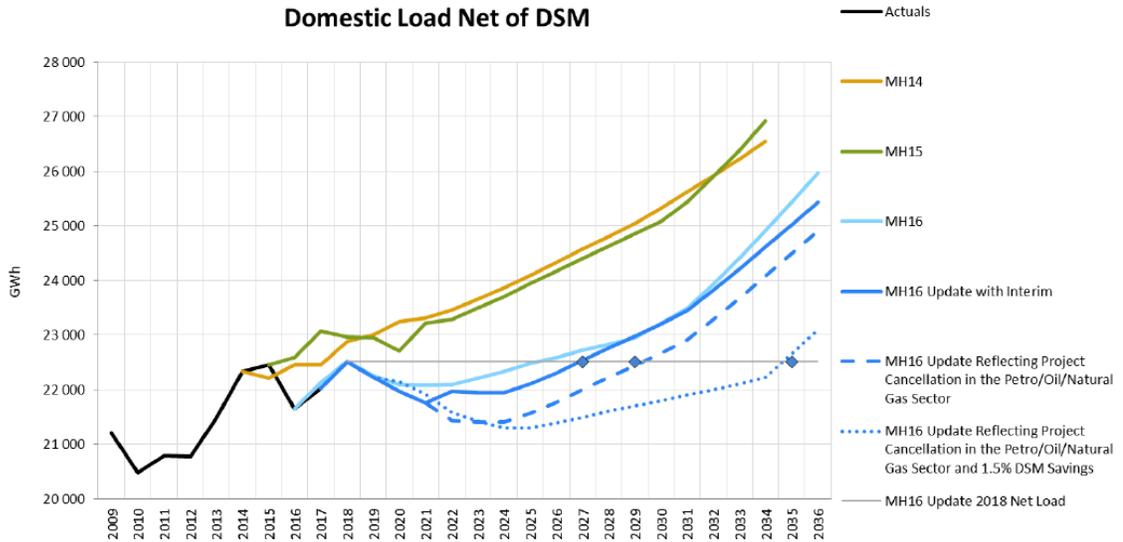
28 29 **8.2 Load Forecast**

30 **8.2.1 Future Manitoba Load Forecast is Trending Down**

31 Manitoba's future domestic load requirements and domestic revenue expectations have
32 deteriorated compared to previous load forecasts and including the impact of future
33 demand side management ("DSM") programs are expected to exhibit no net load
34 growth for the next 10 years as indicated in Manitoba Hydro's direct evidence (Exhibit
35 MH-64).

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2

Figure 8.1 Domestic Load Net of DSM



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Source: Slide 40 of Exhibit MH-64

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Ms. Morrison in her testimony provided preliminary indications as to where the 2017 Fall Update Load Forecast is compared directionally to the 2017 Forecast (Transcript Page 647). Manitoba Hydro has been forthcoming on the reasoning underlying the reduction in domestic load. Ms. Morrison advised that a large project in the petrol, oil and natural gas sector was recently cancelled which results in a reduction of approximately 530 GWh (Transcript Page 1126) to the 2017 Load Forecast (PUB MFR 65 Attachment 1).

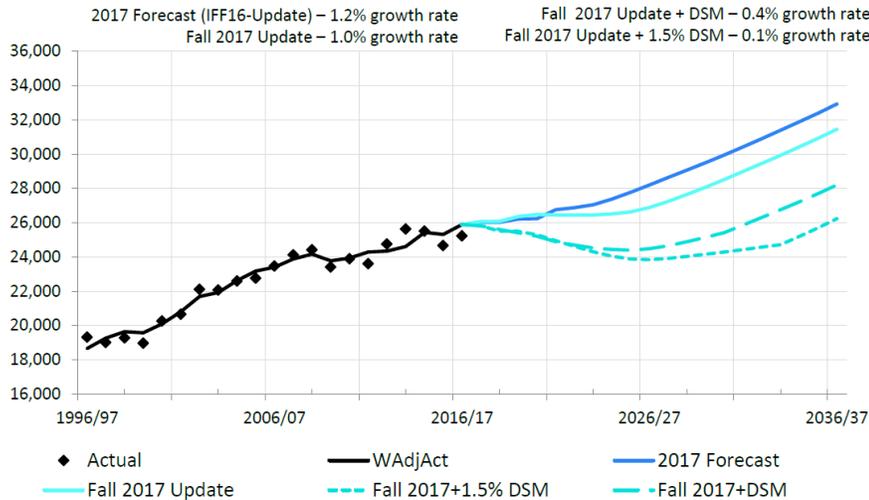
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Slide 20 of the Revenue Requirement Panel Presentation, Exhibit MH-68, compares the 2017 Electric Load Forecast with the preliminary 2017 Fall Update Forecast including the future DSM programs currently forecast in Manitoba Hydro's Power Smart Plan. It is noteworthy that Efficiency Manitoba has a mandate in the Efficiency Manitoba Act of achieving 22.5% over 15 years of overall energy savings targets as compared to Manitoba Hydro's current 2016/17 15-Year DSM plan, which has a cumulative target of 17.3% over a 15 year period. (Transcript Pages 646 to 647). Also presented below in Figure 8.2 is a representation of the 2017 Fall Update Forecast including Efficiency Manitoba's mandated efficiency target of 1.5% of load.

1

Figure 8.2 Preliminary Indications for 2018 Load Forecast

Preliminary Indications for 2018 Load Forecast



2

3

Source: Slide 20 of Exhibit MH-68

4

5

Further discussion on DSM programming and Efficiency Manitoba is contained in Section 8.2.7 of Manitoba Hydro’s written final argument.

6

7

8

8.2.2 Load Forecast Methodology is Reasonable

9

Manitoba Hydro respectfully submits that its 2017 Load Forecast (PUB MFR 65, Attachment 1, page 1) and the supporting methodologies underpinning this Application are reasonable and are a reliable estimate of future energy requirements.

10

11

12

13

Manitoba Hydro’s the load forecast is updated annually to include current information about Manitoba Hydro customer groups in order to produce a reasonable estimate of future load requirements. Key changes incorporated since the 2014 load forecast include updates to the economic inputs such as the forecasts of electricity and natural gas prices, population, GDP and income, and a change for potential long term growth in the Top Consumers sector (Transcript Pages 641 to 643). As Ms. Morrison stated at Transcript Page 641, “some model enhancements were pursued with the change to the top consumers having a notable impact upon the long-term forecast. This enhancement was explored specifically to address past PUB concerns regarding the potential inappropriate upward adjustment in the forecasting for this sector”.

14

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1
2 As noted above, Daymark was contracted to review the reasonableness of Manitoba
3 Hydro's Load Forecast and its supporting methodologies. In summarizing the overall
4 findings of the Daymark Energy Advisors review of Manitoba Hydro's load forecasting
5 methodologies, Ms. Kelly concluded:

6
7 *"Manitoba Hydro's forecast methodologies are reflective -- fully reflective of*
8 *industry practice. I've seen exactly what they're doing in other places before, and*
9 *other - - most utilities are relying on similar tools and technologies to do their*
10 *forecasts"* (Transcript Page 3895)

11
12 Daymark identified the following key findings regarding Manitoba Hydro's base forecast
13 for consideration:

- 14 • The Top Consumers projected long term growth was considered conservative in
15 comparison to the method utilized in previous forecasts;
- 16 • The population forecast may be under-forecasting based on the historical evaluation
17 of previous population forecasts;
- 18 • Electricity price elasticity values may be incorrectly estimated based on the
19 evaluation of the econometric models currently in use by Manitoba Hydro;
- 20 • The possibility of fuel switching/substitution to an alternative fuel type or fuel
21 source due to the increase in electricity prices in all sectors.

22 (Page 5 of Daymark Energy Advisors Report - Forecast Revised, Exhibit DEA-2-1)

23
24 Although Daymark Energy Advisors identified key findings and possible enhancements
25 regarding several elements of the load forecast and indicated that the load forecast may
26 directionally be conservative, Ms. Kelly acknowledged during her testimony that
27 Manitoba Hydro regression equations of each sector is appropriate in total based on the
28 statistics of the regressions evaluated (Transcript Pages 3993 to 3994).

29
30 Daymark also identified a number of enhancements for consideration by Manitoba
31 Hydro in development and reporting of future Load Forecasts (Page 64 of Exhibit DEA-2-
32 1):

- 33 • Consider scenario analyses by developing alternative load forecast to complement
34 the base forecast and evaluate uncertainty utilizing stochastic risk assessments;

- 1 • Incorporate additional years of data in the development of the weather-normalization methodology;
- 2
- 3 • Move to a shorter period in the definition of defining the weather normal year from
- 4 the existing 25 year period;
- 5 • Provide greater transparency in the review and testing of econometric models
- 6 underlying the electric load forecast.
- 7

8 As noted in Manitoba Hydro's Written Rebuttal Evidence on Daymark, Exhibit MH-83, a
9 number of these proposed enhancements have already been considered and some
10 reviewed by the PUB, such as the use of 25 years for determining Weather Normal.
11 (Page 13 of Exhibit MH-83).

12

13 **8.2.3 Top Consumers and Potential Large Industrial Load ("PLIL")**

14 As discussed at page 21 of PUB MFR 65 Attachment 1, Manitoba Hydro's Top Consumers
15 segment is comprised of a limited number of customers spread across a broad grouping
16 of differing industry sectors. The number of customers within each sector is relatively
17 small with no one sector having an overwhelmingly larger concentration of customers
18 than other sectors. Variables related to facility age and technologies employed within
19 industrial facilities located in Manitoba reflect different levels of competitiveness within
20 a global industrial landscape.

21

22 Daymark's Ms. Kelly acknowledged, as a former forecaster, that preparing a forecast of
23 the Top Consumers sector is challenging:

24

25 *"It's -- it's a very difficult job to predict, as pointed out earlier in some of the work*
26 *that the Consumer Coalition was -- was showing us. They are very large*
27 *consumers. They are very lumpy. They have their own business plans and they --*
28 *they are driven by their own business indices. It's very difficult to forecast."*

29 (Transcript Page 4036)

30

31 Manitoba Hydro recently changed its approach in forecasting Top Consumers where the
32 threshold to be considered a Top Consumers changed from a load of approximately 6
33 MW to 25 MW in the 2017 Load Forecast (Page 2 of Exhibit MH-83). The PLIL
34 methodology change made in the 2017 Load Forecast was undertaken in response to
35 recommendations and concerns expressed by the PUB following the Needs For and

1 Alternatives To (“NFAT”) and 2015/16 & 2016/17 General Rate Application (“GRA”) proceedings. For example, the PUB in Order 73/15 found that:

2
3
4 *“There is evidence that Manitoba Hydro consistently over-estimates the Top*
5 *Consumers load growth. The first year of each load forecast for the past five*
6 *years over-estimated the Top Consumers load in the greater-than-100 kV sub-*
7 *class. The PLIL does not recognize the last test years of near-zero load growth in*
8 *the Top Consumers sector, or than using PLIL in addition to large pipeline load*
9 *additions overlaps in some years and may be double-counting. The Board sees*
10 *Manitoba Hydro’s PLIL as an in appropriate upward adjustment that does not*
11 *reflect the recent Top Consumers load growth history. The Board recommends*
12 *that Manitoba Hydro take a more rigorous approach to forecasting the Top*
13 *Consumers load.”* (Page 78 of PUB Order 73/15)

14
15 Daymark’s Scope of Work directed it to review Manitoba Hydro’s 2017 Load Forecast
16 and assess the changes with respect to the 2014 Load Forecast (DEA Exhibit-2-1,
17 Appendix A, Item #8). Daymark noted that the more conservative PLIL method used in
18 2017 forecasted 523 GWh less load than using the 2014 method and 2017 data over the
19 20-year forecast period. This result is not unexpected and was implemented to address
20 the concerns expressed by the PUB. The change in forecasting methodology for PLIL
21 better represents the expected growth in this sector (Page 2 of Exhibit MH-83).

22 23 **8.2.4 Population Forecast**

24 In its initial report, Daymark identified a possible area for improvement with respect to
25 Manitoba Hydro’s treatment of population forecast within the Load Forecast.
26 Recognizing that Manitoba Hydro utilizes external agencies for Manitoba’s population
27 forecast, Daymark’s concern was driven by its evaluation of previous population
28 forecasts, which on average were under-forecasting population trends.

29
30 Manitoba Hydro addressed the Population forecast accuracy regarding the impact of the
31 Provincial Nominee Program when comparing to population forecasts prior to the
32 announcement of the Provincial Nominee Program in 1999 (Exhibit MH-83). When
33 evaluating recent forecasts since the inception of the Provincial Nominee Program,
34 Daymark confirmed in response to Coalition/IEC Daymark Load 7(b) and further

1 confirmed in Undertaking 45, Exhibit DEA-12 that Manitoba Hydro's more recent
2 population forecasts have not been under-forecast.

3 4 **8.2.5 Price Elasticity well within Literature Review**

5 Manitoba Hydro currently utilizes econometric models incorporating the impacts of
6 electric price elasticity. Future forecasted price increases are included as part of the
7 analysis to capture the reduction in electrical consumption by customers as a response
8 to increasing electric prices.

9
10 Although Dr. Yatchew's review of Manitoba Hydro's electricity price elasticities initially
11 suggested that Manitoba Hydro electric price elasticities are somewhat lower than
12 those suggested by his research, he acknowledged that Manitoba Hydro's price
13 elasticities are well within the range of price elasticities identified by the literature
14 referenced within his expert testimony (MH/Yatchew I-1(b)).

15
16 While studies from other jurisdictions may be useful in providing certain insights, they
17 should be used with caution as the production of price elasticities values are not
18 necessarily applicable to Manitoba, and it is not prudent to simply adopt a price
19 elasticity found in any specific study without understanding the conditions and drivers
20 underpinning that value. Differences between Manitoba and other jurisdictions that
21 should be taken into consideration include starting price, rate structure, and average
22 versus marginal pricing and cross price effect with other fuels. All non-price effects must
23 be accounted for in order to minimize the potential for double counting, such as double
24 counting the effects of an economic downturn, codes and standards, conservation rate
25 programs and DSM programming. Dr. Yatchew identifies that Manitoba Hydro electric
26 prices are low by national standards and it is possible that the response to price
27 increases could be attenuated until the price crosses a certain threshold (Page 32 of Dr.
28 Adonis Yatchew Report, Exhibit AY-1). Although Dr. Yatchew acknowledges the difficulty
29 in assessing the threshold in his response to MH/Yatchew I-5, it is certainly plausible for
30 Manitoba to have slightly lower price response than jurisdictions with higher electricity
31 prices.

32 33 **8.2.6 Evidence presented during public presentations**

34 Dr. Garland Laliberte's submitted both a paper and PowerPoint presentation presenting
35 his view of Manitoba Hydro's Load Forecast and Load Forecasting in general. Manitoba

1 Hydro must address a few of the assertions and recommendations presented by Dr.
2 Laliberte, which demonstrates that Dr. Laliberte misinterpreted the data, and thus made
3 erroneous conclusions regarding Manitoba Hydro's Electric Load Forecast.
4

5 Dr. Laliberte discussed during the presentation that Manitoba Hydro's annual load
6 growth of 1.2% is higher than projections in other areas within North America, which
7 are forecasting load growth from about a .5% to 1% (Transcript Page 3567). While other
8 jurisdictions are predicting on average less than 1 percent, those growth rates include
9 the impacts of energy efficiency initiatives in other jurisdictions whereas the 1.2% load
10 growth for Manitoba Hydro referenced by Dr. Laliberte does not include future program
11 based DSM. In the 2017 Load Forecast (Page 58 of PUB MFR 65 – Attachment 1),
12 Manitoba's expected annual load growth including the impacts of program-based DSM
13 initiatives is forecast to be 0.7%, well within the range of annual growth rates currently
14 forecast in other jurisdictions.
15

16 Dr. Laliberte also presented financial impacts on domestic revenue from calculations
17 based on a simple 10-year linear extrapolation in comparison to Manitoba Hydro's
18 electric load forecast. During cross examination by the Consumer Coalition, Dr. Laliberte
19 admitted that a simple linear regression for the purpose of Load Forecasting is not what
20 he is suggesting Manitoba Hydro undertake as a methodology enhancement. When
21 asked about the technique utilized by Dr. Laliberte, Ms. Kelly of Daymark Energy
22 Advisors stated:
23

24 *"this...approach of... using just a simple trend line, ...as Suman pointed out,*
25 *misses a lot of underlying explanatory variables and relationships that -- that*
26 *change the forecast from time to time. Back in the '50s and '60s, before I went*
27 *into forecasting, there was the better opportunity to use this kind of approach,*
28 *because they were building like crazy, everybody was growing. It was -- it was*
29 *postwar make-up. For a lot of time, that wasn't happening. And I remember*
30 *talking to my mentors and trainers who talked about the days when they just*
31 *took a log-linear, a piece of paper, and drew a line, and that was forecast, and it*
32 *was going to be right, which is not something that you can see today. And simp -*
33 *- making this simple is crazy."* (Transcripts Page 4100, lines 1-15)
34

1 Manitoba Hydro submits that no weight should be placed on Dr. Laliberte's assessment
2 of Manitoba Hydro's forecast, its methodologies or potential financial impacts resulting
3 from his analysis.
4

5 **8.2.7 Demand Side Management and Efficiency Manitoba**

6 Manitoba Hydro's DSM plans have played a key role in meeting energy needs in a
7 sustainable manner and assisting customers in reducing their energy bills. The most
8 current 2017/18 DSM Plan was filed in response to PUB MFR 61.
9

10 There has been much discussion during this hearing about what level of DSM should be
11 included in Manitoba Hydro's long term financial projections. Mr. Bowman testified that
12 Manitoba Hydro's baseline IFF includes DSM activities that *"are benchmarked too high,*
13 *given the facts facing us"*. (Transcript Page 6079)
14

15 The 2016/17 DSM Plan – 15 Year Supplemental Report, filed as Appendix 7.2 of the
16 Application outlines the corporation's current DSM plan over the next 15 years, and
17 includes the best projections available at this time. As Ms. Morrison has testified, it
18 would be inappropriate for Manitoba Hydro to propose a different plan on behalf of
19 Efficiency Manitoba. As Ms. Morrison testified:
20

21 *"The reason we did not -- we did not include this table in the 2017/'18 one year*
22 *DSM plan is that we did not undertake a 15 year analysis or plan for '17/'18. This*
23 *is because we were aware that the Efficiency Manitoba legislation was being*
24 *tabled and in our discussions with the provincial government, we were basically*
25 *holding constant on the programs we had in place. And so we went and*
26 *undertook in our consultations to develop a one year plan, as we have in the*
27 *past, and that one year plan then became the new plan and we are simply*
28 *carrying forward the -- what was developed under the 2016/'17 15 year plan*
29 *until Efficiency Manitoba can come forward with a revised, updated long-term*
30 *plan."* (Transcript Page 1569)
31

32 Ms. Morrison further clarified this position during cross examination by PUB Counsel,
33 *"That mandate is moving over to Efficiency Manitoba. We are not making any changes*
34 *until that has successfully transferred. That will then be the direction of Efficiency*
35 *Manitoba."* (Transcript Page 2622)

1
2 The 2016/17 DSM Plan – 15 Year Supplemental Report projects average annual DSM
3 savings of 1.2% of load which, although lower than the 1.5% targets identified in the
4 Efficiency Manitoba Act, are at least in the range of the legislated targets and therefore
5 appropriate for the review of this Application. These savings are certainly not greater
6 than those mandated by the Efficiency Manitoba Act and as such cannot be said to be
7 benchmarked too high as suggested by Mr. Bowman.

8 9 **8.2.8 Forecast Conclusion**

10 Manitoba Hydro respectfully submits that the evidence in this proceeding supports its
11 position that the Load Forecast methodologies underpinning this application are
12 reasonable and are a reliable estimate of future energy requirements.

13 14 **8.3 Export Revenue Projections are Reasonable**

15 **8.3.1 Consensus Price Forecast Process is Reasonable**

16 For the MH16 Update, Manitoba Hydro prepared a Reference Case long-term export
17 price forecast in spring 2017, using the consensus of four external price forecast
18 services. In simple terms, the “consensus” is a simple average of the price forecast
19 consultant forecasts. In connection with the review of Manitoba Hydro’s Export Price
20 Forecast, Daymark was provided individual price forecaster data in electronic format in
21 confidence for their review.

22
23 In its Export Pricing and Revenues Review report, Daymark confirmed this approach
24 stating:

25
26 *“MH received electronic information from each vendor, which represented the*
27 *entirety of the information available for reviewing and characterizing the*
28 *forecast received. For all four vendors that information was provided via one or*
29 *more spreadsheets. All four vendors provided annual energy and capacity prices.*
30 *Some provided monthly energy prices as well. MH used a consensus approach,*
31 *taking the average of the annual energy and capacity prices to create a single*
32 *forecast, which MH called their reference energy price forecast” (Page 36 of*
33 *Daymark Energy Advisors Report – Export, Exhibit DEA-1).*
34

1 Manitoba Hydro's consensus approach to long term price forecasting has been
2 externally reviewed a number of times, including during the NFAT and the 2010 Risk
3 Review/ KPMG External Quality Review. It is the accepted approach.
4

5 On Slide 22 of Daymark Energy Advisors Export CSI Presentation, Exhibit DEA-9 CSI and
6 Transcript Pages 4348 to 4350, Daymark makes comparisons to other forecasts,
7 including information from the U.S. Energy Information Administration. Comparisons
8 of the Reference Price forecast with other older price forecasts or other unidentified
9 price, natural gas or carbon forecasts are not meaningful or useful. Manitoba Hydro
10 incorporated the current price forecast information from its independent price forecast
11 consultants regarding natural gas and carbon into its forecast at the time MH16 Update
12 was prepared. The price forecast represented the best independent estimates available
13 to Manitoba Hydro at that time.
14

15 Daymark provided in Exhibit DEA-9 CSI the identities of each individual consultant, the
16 individual price forecast detail, and the consensus price forecast. Daymark did not raise
17 any objections to the consensus price forecast process, finding that *"MH used the
18 average of the four forecasts as its reference case"* (Page 50 of Exhibit DEA-1).
19

20 **8.3.2 Other Export Revenue Projections are Reasonable**

21 The export revenue projections in the MH16 Update also incorporate information
22 including revenues sourced from contracted energy and capacity sales (Page 60 of
23 Exhibit DEA-1) and the exportable energy and capacity volumes (Page 52 of Exhibit DEA-
24 1).
25

26 Daymark noted that Manitoba Hydro's firm contract revenue forecast is a contract-by-
27 contract analysis of the terms of each contract (Slide 34 of Daymark Energy Advisors
28 Export Presentation, Exhibit DEA-7). With regard to the contracted energy and capacity
29 sales (firm contracts revenues), Daymark found that

- 30 • *"Manitoba Hydro's revenues forecast from existing export contracts is reasonable"*
- 31 • *"The treatment of those contracts is consistent with the analysis of those contracts in
32 NFAT"*
- 33 • *"The treatment of the new contracts is consistent and the resultant revenues
34 forecast is reasonable"*

35 (Slide 35 of Exhibit DEA-7)

1
2 Daymark also reviewed the forecasting methodology used by Manitoba Hydro to
3 determine the exportable energy and capacity volumes, considering the flow and inflow
4 conditions, reservoir levels, as well as other hydrologic inputs that are applied to the
5 computer modeling of the hydro system. Daymark found *“that the methodology used by*
6 *MH for both the short-term and the long-term periods appeared to be reasonable.”*
7 (Page 52 of Exhibit DEA-1). With regard to the forecast surplus capacity and energy
8 volumes, Daymark found that:

- 9 • *“MH’s forecasting methods are consistent with past practices”*
- 10 • *“The forecast reasonably represents the average supply considering the range of*
11 *hydrologic uncertainty.”*

12 (Slide 38 of Exhibit DEA-7)

13
14 These findings are significant. The export revenue projections also depend on the
15 surplus volume estimates and the firm contract revenue estimates, and Daymark found
16 these key components to be reasonable and appropriate.

17 18 **8.3.3 Manitoba Hydro Uses Multiple Sources in its Short-Term Export Price Forecast**

19 Manitoba Hydro has used a total of four vendor forecasts along with Intercontinental
20 Exchange (“ICE”) forward power prices and recent historic prices experienced in the
21 market in preparing the short term forecast of export revenues for IFF16 and IFF16
22 Update. Manitoba Hydro notes that Daymark’s evidence (Transcript Page 4362) in this
23 respect is incorrect, and that it appears that Daymark did not apprehend the multiple
24 sources used in the development of the short-term export price forecast used in
25 operations and in projecting export revenues in the early years of its Integrated
26 Financial Forecast.

27
28 Manitoba Hydro’s use of multiple forecast sources for the first two years of the IFF is a
29 more thorough approach than what Daymark understood to be the process. Daymark
30 concluded based on its review and understanding of the data and methodology that it
31 was reasonable (Page 35 of Exhibit DEA-1). Manitoba Hydro submits that this conclusion
32 remains valid, and, if anything, is strengthened by the use of additional forecast sources.
33

1 **8.3.4 Review of SaskPower Sale and Transmission Construction Deemed Beneficial**

2 Mr. Cormie provided an overview of the 100 MW SaskPower sale starting at Transcript
3 Page 663 and Slide 30 of Exhibit MH-68. Daymark reviewed the economic justification
4 for the sale and associated transmission project and found *“The transaction, including*
5 *the transmission project, remains in the best interest of Manitoba Hydro and its*
6 *ratepayers”* (Slide 18 of Daymark Energy Advisors - Saskpower Presentation, Exhibit
7 DEA-10). The revenues and costs associated with this sale were included in Manitoba
8 Hydro’s financial forecast MH 16 with Update.

9
10 **8.3.5 No Additional Capacity Resources Required in MISO Until 2023 Time Frame**

11 Midcontinent Independent System Operator (“MISO”)’s conclusion in its MISO
12 Transmission Expansion Plan (“MTEP”) 2017 regarding the need date for additional
13 capacity resources in its market region was *“Beginning in 2023 MISO capacity is*
14 *projected to fall below the PRMR [Planning Reserve Margin Requirement] and remain*
15 *there for the rest of the assessment period (Table 6.2-1)”* (MH/DAYMARK (EXPORTS) I –
16 1). MISO’s conclusion is significant, as if there is no demand for additional capacity,
17 there can be no value for generation capacity and in turn no premium in Manitoba
18 Hydro’s revenue projections until 2023. At page 72 of Exhibit DEA-1, Daymark agreed
19 with MISO’s conclusion in stating *“that it is likely that MISO will be short capacity within*
20 *the next ten years, possibly as soon as 2025”*. In their Direct Evidence Daymark changed
21 their position somewhat, stating in various places that *“2022 MISO predicted need for*
22 *new capacity”* with a reference MISO MTEP Table 6.2-1 (Slide 53 of Exhibit DEA-7), and a
23 *“2023/2024 Year of Need”* (Slide 23 of Exhibit DEA-7) assuming new resources but not
24 new, low certainty resources currently under development are completed.

25
26 Manitoba Hydro accepts MISO’s projection of the summer of 2023 as the need date for
27 additional capacity resources. MISO’s finding is consistent with NERC which stated in its
28 2017 Long Term Reliability Assessment (Page 42 of the NERC - Long Term Reliability
29 Assessment, Exhibit CC-39) that *“The Anticipated Reserve Margin remains above the*
30 *Reference Margin Level of 15.8 percent through the summer of 2022”*. As noted on Page
31 30 of Exhibit MH-83, this need date is subject to uncertainty, and has been deferred
32 over the last five MISO MTEP assessments.

8.3.6 Long Term Dependable Product Premium No Longer Exists

In Tab 3 of the Application at page 14, Manitoba Hydro states, “... *the premium that has historically been applied to the long-term dependable forecast prices has been removed as the achievability of this premium has reduced significantly in the MISO market*”. Historically, the Long Term Dependable Product Premium was applied by Manitoba Hydro based on its ability to leverage what was once an almost unique fixed price carbon free product in the MISO market.

As outlined on Page 25 of Exhibit MH-83, the premium was reviewed during the NFAT and Manitoba Hydro notes that both the PUB and Daymark were previously skeptical of the premium. Daymark (then LaCapra) stated, “*MH provides little justification for the amount of the premium*” (Page 6-61 of Appendix 6 in Manitoba Hydro’s NFAT Submission). In their current report, Daymark now advocates for the inclusion of the premium stating, at Page 61 of Exhibit DAE-1, “*The elimination of the premium in the longer term is not consistent with the longer-term outlook for energy, capacity and clean energy requirements in the Northern MISO region*”. On page 115 in the June 2014 PUB NFAT report, the PUB itself expressed its skepticism of the premium stating, “*The Panel is concerned with the risk that future export contracts may not attract the premium pricing that Manitoba Hydro assumes*”.

Subsequent to the NFAT, Manitoba Hydro made the decision documented in the 2016 Energy Price Forecast, that the addition of the Long Term Dependable Product Premium was no longer appropriate as a result of five changes/ concerns in the export market. Details of the five concerns were included as CSI on Page 59 of Exhibit DEA-1, which was reviewed at Transcript Page 4359.

Manitoba Hydro agrees with Daymark’s finding “*The elimination of the premium appears reasonable for the near term*” (Page 61 of Exhibit DEA-1). However, Manitoba Hydro does not see the return of the Long Term Dependable Product Premium in the longer term, in 2023 and beyond, when new capacity resources may be needed in MISO. As noted on page 27 of Exhibit MH-83, wind generation and more recently solar generation have increased significantly in the MISO market, with the four states in Manitoba Hydro’s immediate market already generating from 17 to 36% of their own supply from wind generation in 2016. Accordingly, Manitoba Hydro is no longer the only renewable option for potential customers seeking a carbon free renewable product

1 at a fixed price. Competition from low cost renewables does not support a premium for
2 long-term dependable products at this time, and Manitoba Hydro expects the situation
3 is unlike to improve in the future as wind and solar costs are falling, even as subsidies
4 for wind generation are being phased out.

6 **8.3.7 Value of Generation Capacity in the Future is Uncertain**

7 Potential capacity revenue is a significant uncertainty in the projections of future export
8 revenue. In times of oversupply, the value of generation capacity can be very low. This
9 uncertainty was recognized by the PUB in its NFAT report when it stated on page 108
10 *“However, it has not been conclusively demonstrated that all of this surplus dependable*
11 *energy will achieve capacity revenues in addition to energy revenues”.*

12
13 Given MISO and NERC findings that MISO’s regional surpluses and potential resources
14 are sufficient to meet requirements in the 2019 - 2022 timeframe, it follows that there is
15 expected to be little or no demand for additional capacity resources in the MISO market
16 through the end of 2022. In times of capacity surplus, as in the current situation, the
17 capacity price is likely to be close to zero. For 2023 and beyond, if MISO load forecasts
18 prove to be correct, there is the potential for a need for new capacity, and in turn a
19 potential for some yet to be determined value for generation capacity at that time.

20
21 In determining the export revenue forecast, and in consideration of significant
22 uncertainty associated with the value of generation capacity in the long term, a policy
23 decision has been made by Manitoba Hydro to remove the potential capacity revenue
24 associated with unsold capacity and dependable energy from the revenue forecast. This
25 policy decision reflects the uncertainties and delay in the need for additional capacity
26 resources in MISO (described as the Receding Horizon for the Capacity Need Date in
27 MISO) (Page 30 of Exhibit MH-83). The continued delay in the need for additional
28 capacity resources in MISO is a result of:

- 29
- 30 • Load growth, which for the US as a whole, and for MISO in particular, is low by
31 historical standards, and has been trending even lower for 20 years. MISO’s most
32 recent projections of load growth are in the 0.3% (MH/DAYMARK (EXPORTS) I-1
33 Attachment 1) to 0.5% (Page 31 of Exhibit MH-83) range.
 - 34 • Increasing wind and solar renewables, which MISO considers as providing some
35 capacity to meeting regional peak load requirements in their supply and demand

1 analysis. In MTEP 17, MISO allocated wind generation a 15.6% capacity credit and
2 solar generation a 50% capacity credit (MH/DAYMARK (EXPORTS) I-1 Attachment 1),
3 as a portion of the installed or gross capacity rating, to meet peak load in their
4 supply and demand analysis. This generation capacity from wind and solar reduces
5 the need for generation capacity from other resource types.

- 6 • The deferral of emissions requirements in the US resulting from the Trump
7 administration’s rollback of environmental regulations, the lack of pending carbon
8 legislation, and the pending plans to terminate the Clean Power Plan have (PUB MFR
9 79U) allowed existing thermal power plants, which may have been forced to close
10 due to environmental regulations, to stay open, deferring the need for new capacity
11 resources.
- 12 • Resource planners and generation developers within MISO already have under
13 development significant generation with which to replace any expected generation
14 retirements within MISO. As stated in MTEP 2017 *“MISO’s West Region alone faces
15 more than 22 GW of generation under study”* (MH/DAYMARK (EXPORTS) I-1
16 Attachment 1).

17 18 **8.3.8 Export Prices are Continuing to Fall**

19 Electricity prices in MISO have been on a general downward trend since 2008 driven in
20 large part by falling natural gas prices. The August 2017 Staff Report to the Secretary on
21 Electricity Markets and Reliability prepared by the US Department of Energy (DOE Staff
22 Report) has an entire section titled *“Falling Natural Gas Prices”* (MH/DAYMARK
23 (EXPORTS) I-1 Attachment 1). In discussing falling natural gas prices, the DOE Staff
24 Report notes at page 36 that *“natural gas plants and gas prices have been the largest
25 single driver of spot electricity prices”*. The DOE Staff report also states:

26
27 *“Shale gas development has significantly expanded the availability of natural gas
28 and lowered its cost across the United States and the world. Before the
29 widespread use of horizontal drilling techniques in the past decade, U.S. natural
30 gas prices averaged more than \$7 per million British thermal unit (MMBtu)
31 between 2003 and 2008, and approached \$14/MMBtu in several short periods
32 (including in 2005 after Hurricanes Katrina and Rita reduced production and
33 delivery from Gulf of Mexico sources). Hydraulic fracturing practices spread and
34 made previously inaccessible gas sources economic, causing natural gas prices to*

1 *fall, averaging less than \$3.20/MMBtu between 2012 and 2016” (MH/DAYMARK*
2 *(EXPORTS) I-1 Attachment 1).*

3
4 As indicated in the November 16, 2017 letter from Manitoba Hydro to the PUB which
5 provided the Quarterly Report for the six months ended September 30, 2017,

6
7 *“As of September 30, 2017, on peak opportunity prices were 22% below the*
8 *target in MH16 Update with Interim while off peak prices were 6% below target.*
9 *This represents a further deterioration compared to the quarter ended June 30,*
10 *2017 where on-peak prices and off peak prices were 16% and 4% below target.”*

11
12 The current export market conditions are challenging and very competitive.

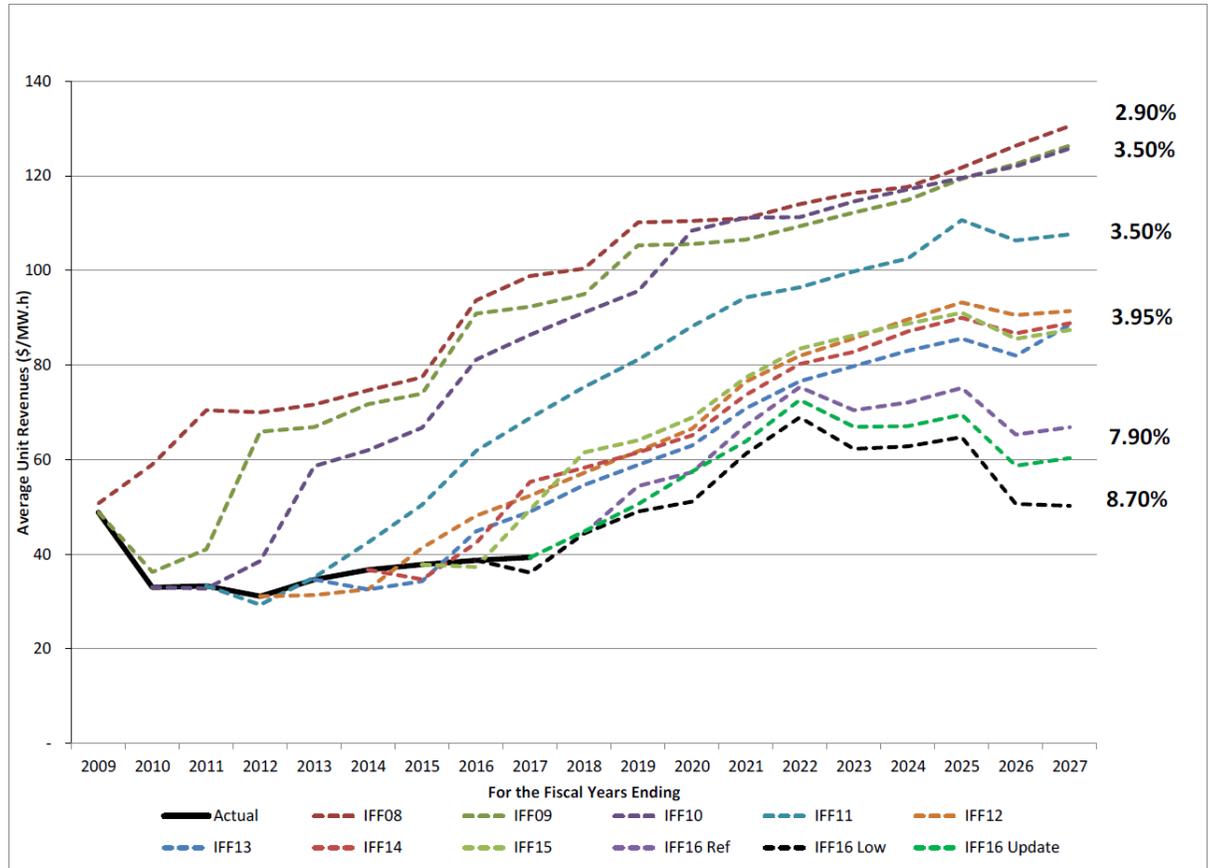
13
14 Dr. Yatchew summarized the market challenges very well:

15
16 *“In any discussion of Canada’s economic circumstances, consideration of the*
17 *effects of the current U.S. administration cannot be ignored. The North American*
18 *Free Trade Agreement is being re-negotiated at the initiative of the U.S. At a*
19 *minimum, this injects considerable uncertainty into trade relations with our*
20 *largest trading partner. The U.S. administration has also altered direction on its*
21 *decarbonization policies, disengaging from the Paris Agreement and making*
22 *efforts to revive the coal industry. Together, these factors are likely to have a*
23 *dampening effect on investment, and weaken prospects for long-term power*
24 *sales agreements that are premised on clean hydro-electric power” (Page vii of*
25 *Exhibit of AY-1).*

26
27 **8.3.9 Manitoba Hydro’s Unit Export Revenue has Historically Been Overestimated**

28 Manitoba Hydro’s average unit export revenue is calculated as total export revenue
29 divided by total export volume. Future projections of the export revenue reflect actual
30 firm contract revenues, as well as revenue for expected future sales based on the
31 electricity export price forecast. As export prices have fallen since 2008, so too has
32 Manitoba Hydro’s average unit export revenue. The history of Manitoba Hydro actual
33 average unit export revenue compared to forecasts from previous IFFs was provided in
34 response to PUB/MH I-153(b) and is reproduced below in Figure 8.3.

1 **Figure 8.3 Progression of Average Export Unit Revenues Graph**
Figure 3.7 Progression of Forecast Average Unit Revenues Compared to Actual Average Prices



2
 3 **Source: PUB/MH I-153(b)**

4
 5 When MH08 was prepared, the expectation for average unit export revenue for 2017
 6 was in the order of \$100/ MWh. In recent years, the actual average unit export revenue
 7 has been just under \$40/ MWh. As near-term actual export prices have fallen, so too
 8 have the long term electricity price forecasts.

9
 10 Average unit export revenues in MH16 Update over the forecast horizon have dropped
 11 nearly 50% from MH08 and over 20% compared to MH15. The decline in actual and
 12 projected average export unit revenues primarily reflects the previously noted step
 13 declines in natural gas prices, with declines in carbon pricing outlook and increasing
 14 amounts of wind and solar generation also contributing. As can be seen in Progression

1 of Average Export Unit Revenues graph, each of the nine Integrated Financial Forecasts
2 in the 2008 thru 2015 period have significantly overestimated the current actual
3 average export unit revenue. This is not a result of any bias of Manitoba Hydro but
4 rather reflects a decade long decline in natural gas and electricity market prices in the
5 independent price forecasts Manitoba Hydro utilizes to form its consensus price
6 forecast.

7
8 A review of the Progression of Average Export Unit Revenues graph shows that for the
9 IFF16 Update, the average export unit revenue is projected to increase from around \$40
10 today to around \$70/ MWh in 2022. Given the history of underperformance of the unit
11 export revenue projections over the last nine year due to declining price forecast, there
12 is reason for concern as to whether the export revenue will increase to the degree
13 anticipated. Daymark asserted that *“the reference case energy market price forecast
14 and the resultant energy revenues are susceptible to be biased low”* (Page 1 of Exhibit
15 DEA-1) suggesting that the forecast is too low and actual results will be higher. Actual
16 experience over the last nine years has been the opposite.

17
18 There is much uncertainty as to what will happen five years in the future, in the 2023
19 time period, when MISO may need new capacity resources. As Mr. Shepherd noted,

20
21 *“...one (1) of the key adjustments we've made is to reduce the expectation that
22 we are going to be able to achieve premiums in export pricing associated with a
23 firm or capacity demands and – and that's based upon a view that those are very
24 uncertain at this stage that we will be able to actually achieve that level of
25 pricing premium. So we've been more conservative in our export pricing forecast,
26 and I think given our track record of it seems like regularly overestimating export
27 pricing, being a little bit more conservative is the prudent thing to do”* (Transcript
28 Page 296).

30 **8.3.10 Impact of Potential Longer Term Premium and Generation Capacity Revenue** 31 **Doesn't Change Current Rate Needs**

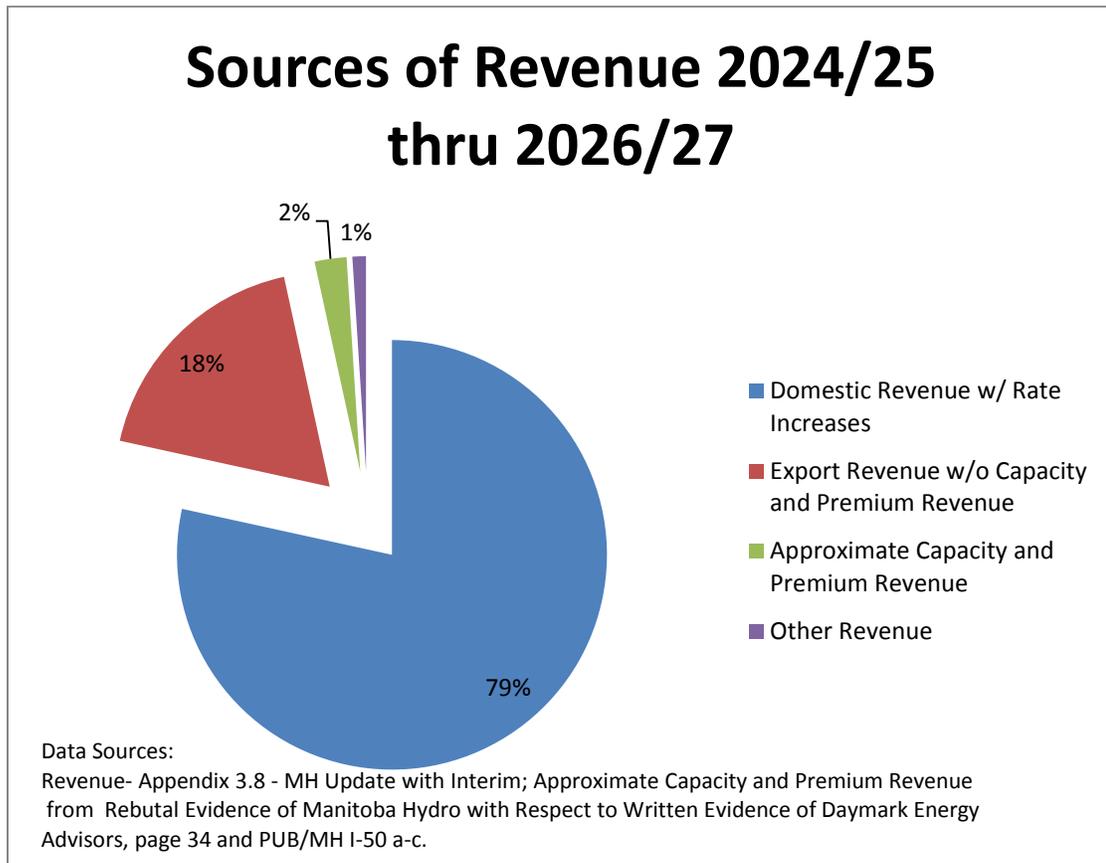
32 Manitoba Hydro does not believe there is any realistic potential for the Long Term
33 Dependable Product Premium to return for the MISO market, given competition from
34 other renewables, on any time horizon. For 2023 and beyond, if MISO load forecasts
35 prove to be correct, there is the potential for a need for new capacity, and in turn a

1 potential for some yet to be determined value for generation capacity at that time.
2 Should additional capacity sales be contracted, the associated forecast revenues can be
3 added into the IFF at the specific contract prices. There is likely to be two further
4 General Rate Applications between now and 2023 to make this adjustment. However,
5 for the purposes of the 2017/18 and 2018/19 test years, Manitoba Hydro's assumptions
6 are reasonable and prudent in the circumstances.

7
8 As noted in Manitoba Hydro's Rebuttal Evidence, even if one were to include the Long
9 Term Dependable Product Premium and the value of generation capacity after 2024/25
10 as suggested by Daymark, the impact on net export revenues for the period 2024/25 to
11 2026/27 would be in the order of \$200 to \$300 million (PUB/MH I-50a-c CONFIDENTIAL¹).
12 Manitoba Hydro's projected total revenue for this three year period, based on MH16
13 Update with Interim (Appendix 3.8 Revised) is in the order of \$3.5 billion per year and
14 about \$10.4 billion for the three year period. Accordingly, the estimate of \$200 to \$300
15 million represents a very small portion of total revenue requirement some 7 to 10 years
16 into the future, as shown in Figure 8.4 below.

1

Figure 8.4 Sources of Revenue 2024/25 – 2026/27



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The uncertainty of the potential premium and generation capacity revenue in the 2023 time period and beyond is well within the range of forecast uncertainty, and could be accounted for in future financial forecasts, should it materialize. The potential for such premium and capacity value in the 2023 and beyond timeframe does not have any impact on the current rate requests before the PUB.

10

8.3.11 Current Water Conditions Have Not Changed Significantly from IFF16 Forecast and Are Less Favourable Than IFF16 Update.

11

12

13

14

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17

Mr. Cormie provided an update of water conditions in his direct testimony (Transcript Pages 657 to 659). With reference to slides 24 through 26 of Exhibit MH-68, he explained how inflow conditions declined from flood conditions in the early summer of 2017 (when MH16-Update was prepared) to close to average by late summer, and were close to average as of December 2017.

1 River flows and storage remain close to average and cumulative winter precipitation
2 (November 1st through February 1st) is slightly below average. Carry forward storage
3 into 2018/19 is similar to what was projected in MH16. Conditions continue to be such
4 that Manitoba Hydro cannot confidently rule out the occurrence of flood or drought in
5 2018/19. The range of uncertainty in flow related revenues is approximately \$500
6 million - between \$100 million favourable and \$400 million unfavourable (Slide 35 of
7 Exhibit MH-64).

8 9 **8.4 Interest Rate Outlook**

10 Continuation/reliance on rates not seen since Depression era extremely risky strategy –
11 reasons outlined in detail in next section

12
13 Interest rate risk is the risk that future cash flows will fluctuate due to changes in
14 market interest rates. There are a number of forms of interest rate risk affecting the
15 existing debt portfolio. Floating or variable rate debt is subject to interest rate reset risk
16 during the life of the debt as the interest rate becomes adjusted at the periodic reset
17 dates. Refinancing risk pertains to the interest rate exposure that exists upon
18 refinancing a short or long term debt issue at its maturity. On a prospective basis, there
19 is also interest rate risk on borrowings for new cash requirements.

20
21 Given the significant level of upcoming debt financings, the corporation's sensitivity to
22 interest rate changes will be elevated during the next few years. Financial market
23 conditions and the corporation's risk mitigation activities will be especially important
24 during this timeframe.

25
26 Actual interest rates in the Canadian capital markets have generally been on a
27 downward trajectory over the past two decades but since July 2017, the Bank of
28 Canada has raised the overnight rate 75 basis points. The July 2017 interest rate hike
29 was the first increase in this rate in seven years. Interest rates across the yield curve are
30 projected to continue rising in the next few years.

31
32 Manitoba Hydro has been fortunate that the interest rate environment has remained
33 low throughout the beginning of the intensive capital investment period. However, to
34 continue to rely upon historically low interest rates as a means to buffering financial
35 forecasts to reduce revenue requirement is an extremely risky strategy.

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In PUB/MH I-31a (Revised) Manitoba Hydro updated the short and long-term rates based on September 2017 forecast information.

PUB/MH I-31(a) compared the short and long-term interest rates based on the September 2017 forecast and March 2017 forecast (used in MH16 Update with Interim). Manitoba Hydro's September forecast of Canadian long-term interest rates based on a 12 year WATM is 10 to 30 basis points higher than IFF16 Update with Interim until 2021 and then is lower thereafter by up to 25 basis points compared to the March forecast. For Manitoba Hydro's forecast Canadian short-term interest rates, the September forecast is up to 70 basis points higher to 2022 and then up to 20 basis points lower thereafter.

Over the forecast 2018 to 2027, the total impact to finance expense under the September 2017 forecast of interest rates is an increase of approximately \$180 million net of a \$13 million increase in capitalized interest related to Keeyask compared to the March interest rate forecast. Inclusive of modest increases in finance income on cash balances, the higher net finance expense resulting from the higher forecast near term interest rates results in net debt that is approximately \$150 million higher and lower equity of approximately \$150 million by 2026/27. This results in the target 25% equity ratio not being reached until during the 2027/28 fiscal year (PUB/MH I-31a).

Manitoba Hydro will amend its debt management strategy including the WATM of new debt issuance based on changing conditions. These amendments and associated interest impacts will be reflected in the forecast of the day.

1 **9 SUSTAINING CAPITAL**

2 **9.1 All Business Operations Capital investments in the test year are required for the**
3 **sustainable, safe and reliable operations to the benefit of Manitoba Hydro’s**
4 **customers.**

5 Electricity is essential to public safety. The system is expected to function reliably 365
6 days a year, 7 days a week and 24 hours a day. Manitoba Hydro is responsible for
7 managing that system and investing as required to assure the safe, reliable and
8 sustainable operation of the electrical system, while achieving a balance of cost,
9 performance and risk for the customer.

10
11 All of the capital investments planned for the test years in this Application are required
12 for the sustainable, safe and reliable operation of the electrical system in Manitoba.
13 This is supported by the extensive record of evidence on this subject matter in this
14 proceeding.

15
16 Business Operations Capital investments are required to sustain electricity service
17 through the replacement of aging or obsolete assets, capacity enhancements, and
18 expansion due to load growth (Transcript Page 686). Growth and expansion
19 investments are required to connect new customers and meet growing regional
20 demand. In its Direct Evidence (Transcript Page 687), Mr. Wortley notes that Manitoba
21 Hydro is required to be responsive to customer needs and therefore the timing of these
22 investments is out of Manitoba Hydro’s control.

23
24 System renewal accounts for the majority of the sustainment investment, either to
25 replace failed assets or to proactively intervene to address asset deterioration ahead of
26 failure (Transcript Page 688). This was the focus of METSCO’s evidence (METSCO Report
27 prepared on behalf of the Consumers Coalition, Page v, filed as Exhibit CC-19).

28
29 After reviewing all of the evidence on the record of this proceeding with respect to
30 sustaining capital planned for the test years of the Application, it is clear that METSCO
31 does not identify nor make a specific recommendation for even one program or project
32 warranting reduction, deferral or any other form of modification. Instead, METSCO,
33 without providing any specific facts or analysis, baldly asserted that there was
34 insufficient justification for the sustainment renewal funding for the test years (Exhibit
35 CC-19, page 45). This conclusion is specious.

1
2 All of the proactive interventions planned by Manitoba Hydro in the test years are
3 justified by risk assessments performed by experienced operators and subject matter
4 experts with professional expertise based on asset condition and criticality, with
5 appropriate management oversight and approval. As observed by the UMS Group in
6 their Asset Management Gap Assessment, *“Hydro is using risk to support its asset
7 management decisions, mainly with regard to Capital Planning”* (Appendix 5.1 of the
8 Application, page 16). As noted by Mr. Wortley at Transcript Page 689,

9
10 *“We’ve got a high level of confidence that this is the right work at the right time...
11 it is based on the actual condition of the asset or its performance. It’s a risk
12 assessment made by experienced operators and subject matter experts reviewed
13 and approved by line management.”*

14
15 Nothing in the evidence would suggest otherwise. These decisions are made by
16 professionals with many years of collective technical experience and expertise with the
17 sole purpose of achieving what is in the best interest of the customers of Manitoba
18 Hydro. As Mr. Hjartarson, the CEO of METSCO confirmed in cross-examination *“I worked
19 with many professionals from Manitoba Hydro, and -- and they are very knowledgeable
20 in their field. So that's – we absolutely did not contest that.”* (Transcript Page 7006).

21
22 System renewal investments in the test years benefit customers by improving safety
23 and reliability and managing costs. For example:

- 24 • Streetlight replacements and grounding improvements to mitigate safety risks
25 (Manitoba Hydro Rebuttal, page 41, lines 14-17, filed as Exhibit MH-52);
- 26 • Deteriorated pole and cable replacements serve to maintain customer service levels
27 (Exhibit MH-52, Page 41, lines 17-20);
- 28 • Deteriorated apparatus replacements avoid damage to customer and Manitoba
29 Hydro equipment (Exhibit MH-52, page 42, lines 7-15);
- 30 • Upgrades to the spacer-dampers on Bipole I and Bipole II to arrest conductor
31 damage and avoid the costs of much larger future repairs (Exhibit MH-52, page 42,
32 lines 17-27);
- 33 • Life extension works such as pole treatments and cable injection to delay future
34 replacement costs (Exhibit MH-52, page 42, lines 1-2);

- 1 • Remediation of a deteriorated concrete dam to mitigate the risk of dam breach and
2 generation reliability risk at a fraction of the cost of replacing the structure (Exhibit
3 MH-52, page 42, line 29 to Page 43, line 2); and
4 • Upgrading obsolete generator control equipment to assure the reliability of
5 Manitoba Hydro’s largest generating station (Exhibit MH-52, page 43, lines 1-10).
6

7 Delaying sustainment investments in deteriorated assets will result in:

- 8 • Direct and collateral equipment damage due to in-service failure;
9 • Higher costs due to emergency replacement of failed assets being more costly than
10 planned replacement;
11 • Jeopardizing employee and public safety;
12 • Harmful environmental impacts;
13 • Lost export revenue which increases costs to Manitobans; and
14 • Most significantly, customers service interruption.
15

16 Moreover, prolonged under-investment can result in a backlog of deteriorated assets
17 which can threaten the sustainability of operations. METSCO stated in reference to
18 sustainment funding during cross-examination (Transcript Page 7089) *“You cannot*
19 *really just skip it for some time. Your assets do age and you’ll have – you’ll be in real*
20 *problem.”*
21

22 As noted by Mr. Wortley Transcript Pages 2187 to 2188,

23
24 *“It’s the customer, ultimately, who is subject to that balance of cost -- cost*
25 *performance and risk, and essentially, the – the safe, reliable operation of the*
26 *system is deemed to be what’s best for the customer. And so these are the dollars*
27 *are required to protect that safe and reliable operation and make sure that the*
28 *customer -- we’re there when the customer needs us.”*
29

30 To conclude, all test year Business Operations Capital investments are required for
31 sustainable, safe and reliable operations to the benefit of Manitoba Hydro’s customers
32 which Manitoba Hydro serves by striking a reasonable balance of cost, performance
33 and risk.
34
35

9.2 Forecasts of future expenditures will be tested in future General Rate Applications

The Business Operations Capital targets beyond the test years are currently budgeted based on the extrapolation of past asset investment requirements, shaped by the best available information of future trends (see Exhibit MH-52, page 49 and Mr. Wortley's direct evidence at Transcript Page 689). Manitoba Hydro is working towards establishing a budget model for future operations capital in which these budgets will be more closely aligned with quantitative assessments of future risks based on forecasts of asset degradation. This is consistent with UMS' recommendations to close asset management gaps (Appendix 5.1, UMS Report, pages 34-36) and METSCO's recommendation for future work (see Transcript Page 7091, lines 11-19).

However, planned improvements to the budgeting process does not impact or change the fact that all of the capital investments planned for the test years in this Application are required for the sustainable, safe and reliable operation of the electrical system in Manitoba. The appropriate time for the Public Utilities Board of Manitoba ("PUB") to consider and review the merits of capital budgets beyond the test years in this Application is when the budget years in question are included as test years in future General Rate Applications as filed by Manitoba Hydro.

There are some indications of growing demand in sustainment investment levels, most significantly in the potential for coincident waves of similarly aged assets coming to end of life and exceeding historic replacement rates (Mr. Wortley's direct evidence at Transcript Page 690). The Boston Consulting Group also found *"Currently good reliability, but ageing assets a looming issue"* (PUB MFR 72 Attachment, Page 340) and *"System renewal capital investment insufficient to replace aging assets"* (PUB MFR 72 Attachment, page 342). Similar trends are being experienced in the industry as noted by METSCO *"...they're probably not spending enough on system renewal ... Assets are aging at Manitoba Hydro as – as in other places. I – I would not be surprised if that was the story"* (Transcript Pages 7096 to 7098).

While these are indications of potential upward pressure on capital budgets, the demand for capital beyond the test years remains uncertain. This uncertainty is one of the drivers to implementing the tools and processes to enable the forecasting of investment requirements based on further and more refined predictions of asset

1 degradation. As noted in Tab 5 of the Application, three to five years are expected to be
2 required to fully implement and mature these tools and processes.

3 4 **9.3 Asset Management Practices are being Enhanced**

5 Manitoba Hydro is committed to improving its asset management maturity and is
6 proceeding purposely but cautiously to avoid costly missteps (see Transcript Page 693).
7 Manitoba Hydro commissioned an asset management maturity gap assessment by UMS
8 Group (see Appendix 5.1 of the Application). As anticipated, UMS identified gaps that
9 would need to be closed in order for Manitoba Hydro to achieve best practice while
10 also concluding that Manitoba Hydro's asset management maturity compared
11 favourably to North American industry.

12
13 Plans to close these gaps are under development with significant progress anticipated
14 in 2018. Advancing asset management maturity in a large organization like Manitoba
15 Hydro is a complicated endeavour to be accomplished over several years. As described
16 throughout these proceedings (e.g. in Tab 5 of the Application, during the Technical
17 Conference on Asset Management conducted on June 20, 2017, a number of
18 Information Requests, including PUB/MH I-71a-c, and several times in oral testimony
19 including at Transcript Pages 693 and 1419), Manitoba Hydro has a number of
20 initiatives underway to improve capital planning and portfolio management and is
21 proceeding with its Corporate Asset Management Initiative. As Mr. Wortley testified in
22 cross examination (Transcript Page 1421), Phase 2 – the development of asset
23 management policies and strategies – will begin in early 2018 with a detailed roadmap
24 for implementation to follow as Phase 3.

25
26 Also, as described in Section 9.3, Manitoba Hydro is undertaking a number of asset
27 management process improvements in order to achieve its objectives of optimizing the
28 timing of investments to maximize value and forecasting long-term capital
29 requirements of the corporation, which are expected to take three to five years to
30 come to full maturity. This timeline was confirmed to be reasonable by METSCO in their
31 testimony at Transcript Page 6992,

32
33 *“...we do acknowledge and commend Manitoba Hydro for the complex path of*
34 *implementing and entrenching the new asset management tools and the experts*

1 *that preceded us, the Manitoba Hydro's expert put the timeline at about three (3)*
2 *to five (5) years of doing this work. To us, this timeline is not unreasonable."*
3

4 METSCO also confirmed in cross examination that achieving a broader asset
5 management maturity is a larger endeavour and *"it's really a never-ending journey"*
6 (Transcript Page 7058).
7

8 In summary, Manitoba Hydro will continue to focus its efforts on closing the gaps
9 identified by the UMS Group in the immediate and near term while in the midst of the
10 corporate restructuring initiative.
11

12 **9.4 METSCO's Recommendations for Additional Regulatory Oversight Must Be Reviewed**
13 **According to the PUB's Regulatory Mandate and the Incremental Cost of Reporting**

14 In Section 4.0 of their report (Exhibit CC-19), METSCO provided a list of potential
15 accountability tools for consideration by the PUB in establishing additional regulatory
16 oversight and incentive mechanisms for Manitoba Hydro.
17

18 METSCO does not appear to fully understand or appreciate how their suggested
19 recommendations would be consistent with Manitoba Hydro's current regulatory
20 construct. For example, METSCO mistakenly believed that the PUB was responsible for
21 approving Manitoba Hydro's capital expenditures forecast (Transcript Page 7018). Such
22 a misconception has now been recognized by METSCO.
23

24 Additionally, METSCO did not provide any evidence as to the ongoing costs of
25 additional staffing to prepare reports and for the PUB to review and assess the
26 information, both of which add to the cost of compliance ultimately born by the
27 customer.
28

29 For example, at page 46 of its report (Exhibit CC-19), METSCO recommends *"...that the*
30 *PUB establish a range of potential incentive mechanisms to ensure that the applicant*
31 *progresses along its path of continuous improvement in asset management capabilities,*
32 *while exercising increasing cost discipline"*.
33

34 Regulatory incentive mechanisms are employed with investor-owned utilities to
35 provide sufficient financial reward for shareholders to influence the utility to pursue a

1 given set of activities. However, Manitoba Hydro does not have a “shareholder” and
2 therefore incentive based mechanisms are not necessarily appropriate in Manitoba.
3 Manitoba’s cost of service regulatory model sets customer rates according to the
4 revenue required for sustainable operation of the utility for the customer. Moreover,
5 incentives are not required as Manitoba Hydro is committed to continuing its asset
6 management journey, as described in Section 9.3 above.

7
8 METSCO also recommended that the PUB consider an extensive array of new key
9 performance, capital planning, portfolio management and project-specific reporting
10 requirements to be provided to the PUB on a routine basis. A significant effort would
11 be required to create these reports for the PUB with a costly ongoing effort to regularly
12 refresh and publish them.

13
14 Furthermore, such reporting would require additional time and resources on behalf of
15 the PUB and potential costs to engage external technical experts to review and assess
16 the contents of such reports. It is also necessary to consider what the PUB would
17 practically do with such technical information as it will not provide the PUB with
18 information it can utilize in determining rates.

19
20 Manitoba Hydro reiterates that oversight and accountability for managing the
21 Corporation, including implementation of the Corporation’s asset management
22 initiatives, properly rests with the Manitoba Hydro-Electric Board and the Executive and
23 Management teams of Manitoba Hydro. Further, under the existing regulatory
24 framework, there is opportunity for the PUB to review Manitoba Hydro's progress and
25 results with respect to its asset management initiatives as part of the rate-setting
26 process without the requirement for any additional reporting or monitoring as
27 recommended by METSCO. Additional oversight and reporting will ultimately result in
28 Management’s efforts being diverted toward responding to these additional
29 compliance requirements rather than working toward implementation of the
30 improvement initiatives.

31
32 Manitoba Hydro submits that the current regulatory framework already provides
33 opportunity for the PUB to review the Corporation’s progress toward the
34 implementation of its asset management framework. As part of this GRA, Manitoba
35 Hydro has provided a status update with respect to the corporation’s plans to

1 implement an overall asset management framework. In future GRA filings, Manitoba
2 Hydro will provide updates on its progress with respect to the implementation of its
3 asset management initiatives.

1 **10 MAJOR CAPITAL PROJECTS**

2 **10.1 Overview**

3 The Public Utilities Board of Manitoba (“PUB”), and the ratepayers of Manitoba, should
4 be reassured by the detailed review of the construction and management of Manitoba
5 Hydro’s major capital projects that took place during the course of this General Rate
6 Application.

7
8 By way of background, by virtue of Manitoba Order In Council 00092 / 2017 issued April
9 5, 2017, the PUB was assigned the duty of considering capital expenditures by Manitoba
10 Hydro, in its next review, as a factor in reaching a decision regarding rates for services,
11 in order to support setting rates for services in a manner that balances the interests of
12 ratepayers and the financial health of the Manitoba Hydro.

13
14 In its Application filed on May 12, 2017, Manitoba Hydro provided a brief description of
15 its Bipole III Reliability Project (“Bipole III”), its Keeyask Generating Station Project
16 (“Keeyask”), and the U.S. Tie-Line Project made up of the Manitoba-Minnesota
17 Transmission Project in Manitoba (“MMTP”) and the Great Northern Transmission Line
18 in Minnesota (“GNTL”). CEF16 also described the Manitoba-Saskatchewan Transmission
19 Project. Included in those descriptions were the budget estimates in place as at that
20 time, and the projected In-Service Dates for each as of May, 2017. The Application also
21 made reference to the review of those projects by the Boston Consulting Group in 2016.

22
23 With respect to other review and regulation of the above projects, Bipole III underwent
24 a 37 day hearing before the Manitoba Clean Environment Commission in the fall of 2012
25 and the spring of 2013. During that lengthy hearing, system risks and reliability, as well
26 as the Corporation’s requirement for this HVDC transmission line, were reviewed. Issues
27 such as the proximity of transmission lines to each other, and weather risks such as
28 tornadoes and wind events, were discussed. The Manitoba Clean Environment
29 Commission then recommended this project to the Province of Manitoba and a licence
30 was issued in 2013.

31
32 In 2014, the Needs For and Alternatives To (“NFAT”) hearing was held before the PUB,
33 and it included a review of both Keeyask and MMTP.

1 With respect to the Keeyask Project, starting at pages 122 of the PUB’s decision dated
2 June 20, 2014, there is a detailed description of the review done by Knight Piésold, an
3 independent expert retained by PUB. It is stated:
4

5 *“In its scope of work, Knight Piésold was asked to review the cost estimates,*
6 *contracting practices, and the contract provisions. They undertook to determine*
7 *the extent practices were appropriate, costs were reasonable, and measures*
8 *were in effect to address changes or increases in construction costs. The Panel*
9 *focused on Keeyask-related contracting given the immediate nature of decisions*
10 *on whether to proceed with construction in July 2014, and the fact that*
11 *Conawapa construction contracts had not yet been entered into.*

12
13 *Knight Piésold assessed Manitoba Hydro’s costs estimates and contracts. They*
14 *discussed questions about documentation and procedures with Manitoba Hydro*
15 *staff. They then used their experience and past work to assess these practices*
16 *against industry best practices and similar hydropower construction projects.*
17 *Knight Piésold reported to the Panel that many of Manitoba Hydro’s practices*
18 *and procedures were reasonable and appropriate, relative to industry best*
19 *practice. Knight Piésold supported Manitoba Hydro using an Early Contractor*
20 *Involvement process to obtain input from the chosen contractor in order to refine*
21 *the design, construction techniques, schedule, and risk sharing. Knight Piésold*
22 *told the Panel that Manitoba Hydro had made the appropriate choices in the*
23 *various Keeyask Project contracting efforts. The contracting choices were*
24 *designed to secure the most cost effective contracts.”*

25
26 It is also clear that the PUB had the opportunity, at the NFAT hearing, to consider the
27 appropriateness of the General Civil Contract in place with BBE. The following is an
28 excerpt from page 123:
29

30 *“The Keeyask general civil contract is a cost-reimbursable contract, not a fixed*
31 *price contract. This leaves the contract vulnerable to cost escalations as a result*
32 *of: quantity risk, especially in areas where quantities may have been*
33 *underestimated; escalation to the contractor’s cost factors due to labour*
34 *productivity or labour costs; escalation in the cost of supply and equipment; and*
35 *challenges related to adverse weather conditions.”*

1
2 While there was much discussion about the GCC during the 2017/2018 GRA, virtually all
3 of these issues have already been considered by a previous panel of the PUB and a
4 decision made, based upon that analysis on the information available at that time, for
5 the Keeyask Project to proceed. Having reviewed the nature of contract, as outlined
6 above, the PUB concluded (page 34):

7
8 *“There are good reasons to proceed with the Keeyask Project at this time in light*
9 *of the need for new resources, construction expenditures undertaken to date, the*
10 *socio-economic and environmental benefits of the project and the important*
11 *commercial relations that Manitoba Hydro has established both with First*
12 *Nations and through its export contracts. Moreover, there are associated*
13 *reliability benefits with the 750 MW Transmission Interconnection Project.”*
14 *[MMTP]*

15
16 With respect to the new US Tie Line [MMTP], there is a detailed description of the
17 review that was done by the PUB. It stated:

18
19 *“With respect to Manitoba Hydro’s construction cost estimates for transmission*
20 *facilities, the Panel concludes that such estimates are reasonable and*
21 *recommends that Manitoba Hydro be given approval to proceed with the*
22 *construction of a 750 MW transmission interconnection to the United States for a*
23 *2020 in-service date. This interconnection provides increased firm transmission*
24 *access extending into Minnesota, provides important, increased reliability, and*
25 *supports import and export of electricity.”*

26
27 The Province of Manitoba went on to accept the PUB’s recommendations with respect
28 to construction of both Keeyask and MMTP.

29
30 Keeyask and MMTP also underwent rigorous environmental review at hearings before
31 the Manitoba Clean Environment Commission in 2013/14 and 2017 respectively. In both
32 cases, the Commission recommended the projects to the Province of Manitoba. The
33 Province issued a licence for Keeyask in 2014. The Province’s decision with respect to
34 MMTP is pending. MMTP will undergo further scrutiny at the upcoming hearing this
35 spring before the National Energy Board.

1
2 The GNTL underwent regulatory review in the United States and received a Certificate of
3 Need and A Route Permit from the Minnesota Public Utilities Commission, a Presidential
4 Permit from the US Department of Energy and a Section 404 Wetlands Permit from the
5 U.S. Army Corps of Engineers allowing its construction to proceed.
6

7 In addition to review through this current GRA process, the Manitoba-Saskatchewan
8 Transmission Project is regulated under The Environment Act of Manitoba, though due
9 to its size, a hearing will not be required. It is worthy to note that an independent
10 review of this project was conducted by Daymark Energy Advisors for the PUB and it
11 determined that it was in the best interests of Manitoba's ratepayers to proceed with
12 the project. (Transcript Page 5979)
13

14 Although the Intervenors may wish to revisit many of the issues and considerations
15 already reviewed at other regulatory proceedings, the PUB's task and focus is to now
16 consider the Corporation's expenditures to date on these projects in its rate setting
17 decision making process, as well as the budgets going forward.
18

19 Manitoba Hydro provided thousands upon thousands of documents, and responded to
20 dozens of requests for information from MGF Project Services Inc. ("MGF"), an entity
21 retained by the PUB to review Manitoba Hydro's capital expenditure program in relation
22 to the above projects and to provide its opinion on Manitoba Hydro's updated costs for
23 each. Although there are recommendations going forward, some of which may be
24 implemented by Manitoba Hydro where feasible, practical and of value, it is notable
25 that MGF made the following comments in its Report (Redacted MGF Report, Exhibit
26 MGF-2R):
27

28 *"Manitoba Hydro staff are competent and professional". (Page 1)*
29

30 *"The Manitoba Hydro teams on all projects are very capable and dedicated."*
31 (Page 2)
32

33 *"In general Manitoba Hydro is very strong in capturing and reporting costs and*
34 *has a very capable group." (Page 35)*
35

1 *“The team is comprised of a very knowledgeable and capable group”*. (Page 99)

2
3 Further, Manitoba Hydro established a Major Projects Executive Committee that meets
4 twice monthly to review the Corporation’s major projects. (Transcript Page 5543) The
5 Executive report regularly to the Board of Manitoba Hydro to keep it apprised of
6 developments, and quarterly reports are provided to the PUB (Response to Directive 13
7 of PUB Order 73/15). Collectively, these steps should give the PUB and ratepayers
8 comfort, going forward, that project execution is in good hands.

9
10 In terms of the impact on rates, with Bipole III coming into service this year, the finance
11 expense, depreciation, and operating expense associated with it will be reflected on
12 Manitoba Hydro’s income statement and revenue requirement. The Keeyask Project
13 and MMTP/GNTL are net income negative upon entering service and remain net income
14 burdens for a 30 year period. Manitoba Hydro’s financial position now must recognize
15 the new reality of the carrying cost of these significant assets coming into service in the
16 near future (Tab 2 of this Application on Page 48). Specifically with respect to GNTL, as
17 it is not a Manitoba Hydro project, the construction cost contributions payable are not
18 in Manitoba Hydro's capital expenditure forecast. However, they are included in the IFF.
19 (Transcript Page 5067)

20
21 Below is Manitoba Hydro’s position with respect to the issues discussed in relation to
22 each of the major projects discussed at the hearing. The Manitoba-Saskatchewan
23 Transmission Project is discussed in Section 10.4 below.

24
25 **10.2 Keeyask Generating Station Project**

26 As described on page 42 of Tab 2 of the Application, the Keeyask Generating Station is a
27 7 unit 695-megawatt hydroelectric generating station situated at Gull Rapids on the
28 lower Nelson River in northern Manitoba and is owned by a partnership between
29 Manitoba Hydro and four Manitoba First Nations, known as the Keeyask Hydropower
30 Limited Partnership (“KHLP”). Manitoba Hydro has been tasked with the responsibility
31 of managing the construction of the Keeyask Project and the operation of the facility
32 when it enters into service on behalf of the KHLP. The Keeyask Transmission Project will
33 transfer the power produced at Keeyask onto the Manitoba Hydro system when the
34 generating station enters into service, currently projected to be in 2021. (Transcript
35 Page 5562).

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10.2.1 Complex project

The complexity of the Keeyask Project cannot be understated, as it is distinct from Manitoba Hydro’s other major projects, and unique from many other projects across North America, as noted on Slide 24 of the Capital Panel presentation (Manitoba Hydro’s Major Capital Panel Presentation, Exhibit MH-120). It takes many years to build and, unlike many other projects that are built near major centres, it is in a remote location requiring a camp that can accommodate a workforce of 2,400 people. Due to its northern location, there are seasonal constraints on construction. There will be limited warm weather construction time, and extreme cold may also hamper construction. There are numerous environmental and regulatory requirements necessary to protect and preserve the environment, as outlined in the Project’s various licenses and permits. For example, the Project requires diverting a river over a kilometer wide and has extensive diking. Significant structures are required to protect the work area and the natural topography presents challenges as subsurface conditions underlying the river only become evident once cofferdams are constructed and the river bed is exposed. (Transcript Page 5547 and 5552 to 5553) Accordingly, forecasting of both the budget and schedule is challenging, particularly at the early stages of the Project.

10.2.2 Economics

In 2016, the Boston Consulting Group did an analysis and concluded that Keeyask should proceed as the Net Present Value was favorable when compared to the gas option. (PUB MFR 72) In 2017, Manitoba Hydro reviewed the economics once again and, though they have deteriorated to some degree since the 2014 NFAT, the corporation determined that it was still appropriate to continue construction to completion. (Transcript Page 451 and Tab 2 of the Application on Page 48) Cancellation would have increased aggregate revenue requirements in the billions through to 2026/27. (Transcript Page 451 and Tab 2 of the Application on Page 48) As such, its focus is to now deliver this Project on time at the new projected In Service Date (“ISD”) and on budget consistent with the control budget of \$8.7 billion. Manitoba Hydro has put forward a strong plan to do so and is working cooperatively with its General Civil Contractor (“GCC”) to do just that.

1 When Keeyask comes online in 2021, the station will provide clean, renewable energy to
2 Manitobans for generations. The energy generated by Keeyask will support export
3 contracts until it is required to fulfill domestic load requirements.
4

5 **10.2.3 Awarding of the General Civil Contract**

6 Manitoba Hydro's decision to select BBE Hydro Constructors LP ("BBE") for the GCC was
7 reviewed extensively again at this hearing. Hindsight being perfect, others may decide
8 that the selection made several years ago was not the best one when considering the
9 cost-reimbursable target price contract structure for the GCC. However, at the time,
10 and with the full knowledge of the Manitoba Hydro-Electric Board, the selection was
11 made. It is also important to note that the contract model is not determinative of
12 success on a project. Both Muskrat Falls and Site C have contract models different from
13 this GCC. However, both have experienced serious, if not more significant challenges in
14 their projects, and both projects are behind schedule and over budget (Transcript Pages
15 7305 to 7312).
16

17 While it seems fruitless now to re-visit this decision, one that cannot be reversed,
18 Manitoba Hydro will briefly summarize the history and the reasonableness of its past
19 actions.
20

21 The GCC is the largest contract on the Keeyask Project and includes river management
22 structures, rock excavation, concrete and earth structures, and electrical and
23 mechanical work. (Transcript Page 5557) The form of contract entered into is a target
24 price contract where the contractor is reimbursed for actual costs. The contractor is
25 incentivized to perform and minimize cost and schedule as their profit and General
26 Administration and Overhead ("GA&O") are at risk if they exceed their target price
27 (Transcript Page 5560 and 5576).
28

29 The decision to proceed under the cost reimbursable target price contract model was
30 made in 2012 and was part of a larger Project Delivery Strategy for the Keeyask Project.
31 This decision was informed by a number of factors including lessons learned on the
32 recently completed Wuskwatim Generating Station Project, completeness of the design,
33 and allocation of risk and prevailing market conditions at the time (Page 5 of Manitoba
34 Hydro's Written Rebuttal on the MGF Report, Exhibit 117).
35

1 In 2012, as Manitoba Hydro was evaluating various project delivery options, the North
2 American major capital project market was extremely competitive. In this environment,
3 megaproject contractors were not accepting hard money contracts, where risks such as
4 labour availability and productivity would pass on to contractors without substantial and
5 cost prohibitive premiums. This caused owners to proceed with alternative forms of
6 contract, sharing risk where possible, and retaining risks that could not be cost
7 effectively passed on to contractors. (Transcript Page 5558) As acknowledged by Mr.
8 Campbell, contractors had many projects to choose from (Transcript Pages 7303 to
9 7305).

10
11 As described in the hearing, Manitoba Hydro experienced this reality on the Wuskwatim
12 Project when it attempted to tender the GCC as a unit price contract. (Transcript Pages
13 5558 to 5559) A second lengthy procurement process was necessary which exposed the
14 project to greater risk and required a much shorter ramp up schedule for the eventual
15 GCC. These were factors in increasing the cost and lengthening the schedule for
16 Wuskwatim.

17
18 In 2012, when Manitoba Hydro began to evaluate procurement options for the Keeyask
19 GCC, the economic environment was similar to when the Wuskwatim GCC was
20 procured. Having experienced the cost and schedule consequences of attempting to
21 tender a contract model not reflective of the prevailing market conditions, Manitoba
22 Hydro prudently undertook a three stage procurement process, beginning in 2012, that
23 began with an appropriate market sounding exercise to better gauge the market
24 conditions. The result of that sounding exercise was confirmation that it was best for
25 Manitoba Hydro to proceed with a cost reimbursable target price model in order to
26 secure the most competitive pricing considering the major project environment at the
27 time. The process advanced on that basis and culminated in four prequalified
28 proponents bidding on the work in a competitive environment. Manitoba Hydro
29 prepared an internal engineering estimate and also engaged a third party to provide a
30 reference proposal for comparison of the bids. The pricing proposed by the third party
31 was generally in line with the Engineer's Estimate and was within the range of bids
32 received from the four Proponents. (Page 10 of Exhibit MH-117) However, Manitoba
33 Hydro still did an analysis to review BBE's bid, as it was lower, prior to awarding it in
34 March of 2014, and carried a significant labour reserve to deal with potential
35 productivity issues. Again, with the benefit of hindsight, the labour reserve should have

1 been higher to offset the issues experienced with the contractor (Transcript Pages 5677
2 to 5680).

3
4 The PUB and Knight Piésold (“KP”), the independent expert consultant retained by the
5 PUB during the NFAT in 2014, were aware of the contracting methodology of the GCC,
6 having received procurement and contract documents and summaries of the
7 proponent’s bids. On Executive Summary page II of IV of KP’s report dated January 23,
8 2014, in reference to construction management, schedule and contracting plans
9 (rebuttal page 4), KP stated that:

10
11 *“The overall approach follows well documented internal standards developed by*
12 *Hydro’s NGCD [New Generation Construction Division]. The contracting method*
13 *varies by project component but the principal civil works contracting strategy is*
14 *an Early Contractor Involvement (ECI) Project Delivery Strategy. Overall the*
15 *project delivery strategy has been to transfer risk away from Contractors and to*
16 *Hydro in order to better understand and share the risks and obtain a better*
17 *contract price as a result.” [Acronym explanation added]*

18 19 **10.2.4 2016 Issues and Recovery Plan**

20 At the beginning of the 2016 construction season, the Project was generally on track
21 and the project team was forecasting that the control budget of \$6.5B and the schedule
22 with a November 2019 unit 1 ISD would be achieved (Page 15 of Exhibit MH-117). Prior
23 to the start of the concrete work in 2016, a senior off-site review team, comprised of
24 former Manitoba Hydro and BBE senior staff not directly involved in the day-to day
25 activities, was assembled to provide an objective review of the work falling under the
26 GCC to ensure Manitoba Hydro and BBE were doing everything possible to be
27 successful. Although this team identified areas of potential opportunity, the team did
28 not predict the soon-to-be-realized underperformance (Transcript Pages 5569 to 5570).

29
30 In early June 2016, approximately 6 weeks into concrete activities, it was evident that
31 BBE’s actual volume of concrete completed to date was significantly less than planned.
32 Manitoba Hydro immediately took action and took a number of steps that were both
33 timely, and as KCB agreed, appropriate (Transcript Pages 7315 to 7320).

1 On June 19, 2016, Manitoba Hydro formally requested that BBE develop a recovery plan
2 to increase its hiring rate to get more workers on site and to increase concrete
3 production in order to bring production back in line with the 2016 plan. Manitoba Hydro
4 staff continued to monitor the progress carefully during this time (Transcript Page
5 5570).

6
7 By July 2016, it was apparent that the initial recovery efforts by BBE were not going to
8 be impactful enough to recover to the original plan. As well, both BBE and Manitoba
9 Hydro were becoming aware that the work could not be built as it was originally
10 planned, and re-sequencing efforts were undertaken (Transcript Page 5571).

11
12 By the end of the 2016 season, BBE had achieved only 41% of the concrete plan and
13 65% of the earthworks plan. Manitoba Hydro then implemented a formal Recovery Plan
14 in September 2016 (Transcript Pages 5571 to 5572), which included:

- 15 • A call to action for BBE's project team, Executive Sponsors and CEOs;
- 16 • Developing a plan for the continuation of concrete through the severe winter
17 months, which had not been planned previously;
- 18 • Identifying root causes that were impacting performance;
- 19 • Initiating activities to reforecast the cost and schedule for the Project;
- 20 • Undertaking analysis around contractor's claims; and
- 21 • Supplementing the commercial expertise of the team.

22
23 A separate task force was set up to understand the source of the underperformance and
24 to understand the root causes. Multiple root causes were identified and mitigation
25 measures began to be developed (Transcript Pages 5572 to 5573). More specifically, it
26 was determined that the main contributing factors for this underperformance included:

- 27
28 • aggressive concrete production assumptions from BBE's bid that could not be
29 achieved in the current marketplace;
- 30 • slower than planned progress during the ramp-up; and
- 31 • geotechnical and geological conditions, discoverable only upon the commencement
32 of actual construction, which were more challenging than planned and impacted
33 both concrete and earthworks.

1 In addition to these root causes, it was evident that the six month advancement
2 opportunity that existed coming into the 2016 construction season had been lost and
3 the Keeyask Project was facing a potential delay of two to three years or more
4 (Transcript Pages 5572 to 5573). The large variance between actual and planned
5 production also resulted in BBE having no opportunity to earn profit for the remainder
6 of the Project under the existing contract structure. The erosion of profit potential
7 created a risk of worsening performance for the remainder of the project if not
8 addressed.

9
10 Between the Fall of 2016 and Spring of 2017, Manitoba Hydro's Keeyask team worked
11 with BBE to implement the Recovery Plan to improve performance. There were
12 meetings and negotiations between Manitoba Hydro and BBE resulting in a reworked
13 schedule and cost forecast for the civil works and the entire Project. In addition,
14 Manitoba Hydro reviewed its options on how to proceed for the balance of the Project.
15 (Slide 7 of Manitoba Hydro's Major Capital Panel CSI Presentation, Exhibit MH-121) In
16 consultation with legal and technical advisors, and with the approval of the Manitoba
17 Hydro-Electric Board, the decision was made that the least cost option was to continue
18 with BBE and to negotiate an amended contract (Slides 9 to 11 of Exhibit MH-121).
19 Other options would have resulted in a substantial cost increase and significant time
20 added to the schedule, as well as introduced significant risk to the delivery of the
21 Project. (Transcript Page 5574, PUB/MH I-6a-b-CONFIDENTIAL Attachment 1, and CSI
22 Transcript January 23, 2018, Page 23)

23
24 Further, Manitoba Hydro and BBE conducted a joint review of the schedule and saved
25 the Project over one additional year in the schedule. (Transcript Page 5575) Such joint
26 and collaborative efforts will continue throughout the life of the Project.

27 28 **10.2.5 Amending Agreement #7 - Key aspects**

29 Manitoba Hydro could not unilaterally change the terms of the agreement without
30 being in breach of contract. The negotiation included "*gives and gets*" from both parties
31 and, ultimately, an amended agreement was reached (CSI Transcript January 23, 2018,
32 Page 27 and Slide 14 of Exhibit MH-121). The terms in Amending Agreement #7
33 lowered the overall costs and schedule risk for Manitoba Hydro and re-established a
34 reasonable profit that BBE could earn back based on its future performance.

1 Foundational to the agreement was alignment of both parties' interest to deliver at the
2 lowest cost and shortest schedule (Transcript Page 5575). The key features of the
3 amendment are:

- 4 • Schedule and cost incentive pool provides incentive for BBE to earn profit and
5 Manitoba Hydro to minimize Project cost and schedule;
- 6 • GA&O capped at 1.0x the target price; previously capped at 1.3x the target price;
- 7 • Contractor claims “wiped clean”, reducing Hydro’s potential liability and overall cost;
- 8 • Narrowed ability for future claims so the contractor’s focus would, instead, be on
9 getting the work done;
- 10 • Liquidated damages for late delivery were established; the original contract had no
11 damages for late delivery beyond the limitation of the profit pool; (Transcript Page
12 5576)
- 13 • Additional requirements such as a commitment to improve performance, focusing
14 on efficiencies in indirect costs, more controls around cost and schedule, and
15 training requirements were also part of the amended contract.

16 (CSI Transcripts Pages 26 to 36, Slide 63 of Exhibit MH-120, and Slides 17 to 19 of Exhibit
17 MH-121)

18 19 **10.2.6 2017 Outcomes**

20 The revised control budget for Keeyask is \$8.7B (at a P50 contingency level) with a first
21 unit ISD of August 2021 (Slide 65 of Exhibit MH-120). The Project team considered the
22 status of the Project, and the key risks remaining, and determined that this estimate
23 balances the remaining risks and challenges the team to execute to that budget
24 (Transcript Page 5577).

25
26 In the 2017 construction season, the first year of construction after the implementation
27 of the Recovery Plan, significant improvements in both concrete and earthworks
28 production were achieved. Despite the greater complexity of the concrete work in 2017
29 as a result of more curved formwork and work at higher elevations, there was a 12%
30 increase in the concrete volume and a 90% increase in earthworks between 2016 and
31 2017. In 2017, three milestones were achieved which allowed the Project to protect an
32 advanced schedule that could see the units come online earlier than the revised control
33 schedule of August 2021. These milestones include completion of the spillway concrete,
34 installation of the Powerhouse crane and enclosure of the Service Bay and Powerhouse
35 unit 1.

1
2 Despite achieving these key milestones, concrete and earthworks production targets
3 were not fully achieved. There was a deficit of approximately 20% of concrete and 25%
4 earthworks (Transcript Pages 5557 to 5558).

5
6 Manitoba Hydro and BBE have worked to address this issue in 2018. BBE's updated
7 forecast schedule from December 2017 recovers the delay to the GCC work as a result
8 of last year's performance shortfall by extending the concreting season within the
9 enclosure throughout the coldest winter months and adjusts monthly production
10 targets to reflect actual quantities achieved in 2016 and 2017 by the Contractor. The
11 GCC forecast schedule demonstrates that the Service Bay and Powerhouse Unit 1
12 enclosure was achieved on schedule in December 2017, and enclosure of units 2 and 3
13 were achieved in late January 2018 - on or ahead of schedule. The draft tube liner
14 installation by the Turbine and Generator contractor began on schedule in late January
15 2018. The Project is also on track to achieve the diversion milestone where the South
16 Channel of the river will be diverted through the Spillway in late August 2018. (Manitoba
17 Hydro Undertaking 55, Exhibit MH-131 and Confidential Attachment)

18
19 To further improve production in the future and remove inefficiencies, Manitoba Hydro,
20 working together with BBE has (Tab 2 of the Application on Page 46):

- 21 • Developed and deployed an issue management system;
- 22 • Developed refined processes, systems and tools based upon the root cause analysis;
- 23 • Implemented a change management program to enable a culture shift within the
24 Project team; and
- 25 • Developed key performance indicators to report on all deliverables.

26
27 Manitoba Hydro has also taken a more active role in its management of BBE, embedding
28 and integrating its team at the Project site (120 – 150 Hydro employees now working at
29 site beginning in 2016) and introducing "*cold eyes*" reviews by experienced retired
30 contractor employees (CSI Transcript January 23, 2018, Pages 47 to 49).

31
32 Most recently, discussions have just successfully concluded with the Allied Hydro
33 Council and it is expected that the changes to the BNA will bring improvements to
34 productivity and production (CSI Transcript, January 23, 2018, Pages 26 to 36).

1 **10.2.7 Current Forecast at Completion**

2 Manitoba Hydro is currently forecasting a final cost of Keeyask on or below the control
3 budget of \$8.7 B with all units completed ahead of the control schedule (Slide 74 of
4 Exhibit MH-120). Meeting the control budget will require an achievable performance
5 improvement of a further 10% by the GCC and no major risks to materialize (Transcript
6 Page 5725). Manitoba Hydro is committed, despite the skepticism expressed by MGF,
7 that with the improvements made in 2017, and the additional management and review
8 tools and processes in place, we can achieve the necessary productivity increase in
9 2018. Manitoba Hydro and BBE's interventions are intended to create positive change,
10 and efficiencies gained through completing repetitive work on the seven units.

11
12 With four years remaining, construction on Keeyask is approximately half complete.
13 Significant risks remain that have the potential to jeopardize meeting the control budget
14 and schedule, including:

- 15
16 • Execution/productivity rates of the GCC;
17 • Unexpected geotechnical/geological conditions at the South Dam/Dyke;
18 • Unseasonable weather (Slide 73 of Exhibit MH-120)
19 • Loss of site access/work stoppages;

20
21 However, as stated by the MGF team, there is still four years to run on the Project and
22 still much opportunity to get the contractor to perform better in the future (Transcript
23 Page 7191). Manitoba Hydro is continuously evaluating risks and developing mitigation
24 plans to manage the risks when they materialize. The issues with respect to cost and
25 schedule are also not unique.

26
27 Unlike Manitoba Hydro's rigorous budgeting process, and risk-based probability analysis
28 done by John Hollmann of Validation Estimating, MGF provided a loosely estimated cost
29 of \$9.857B that cannot be relied upon. By its own admission, it was not precise, and
30 was only an order of magnitude figure. It could go up, or it could go down (Transcript
31 Page 7185). This value was also developed without a detailed probabilistic risk analysis,
32 or any Monte Carlo analysis, to provide a more realistic range of outcomes and to verify
33 its legitimacy (Transcript Page 7357). MGF also included a 10% contingency, or almost
34 \$900 million, on top of their forecasted cost increases due to BBE performance not
35 meeting the plan. Further, it did not factor in any of the mitigation activities being

1 undertaken by both Manitoba Hydro and BBE (MGF Presentation (Keeyask -MGF
2 Estimated Project Value), Exhibit MGF-4–1 and CSI Transcript, January 31, 2018, Pages
3 39 - 40).

4 5 **10.2.8 2018 Plan and key upcoming activities**

6 To improve outcomes in 2018 and beyond, Manitoba Hydro is working in close
7 collaboration with BBE on execution planning, and is exerting greater oversight of BBE's
8 construction management to improve BBE's performance. This initiative will continue to
9 be a focus in 2018 and for the remainder of the civil contract. Manitoba Hydro has
10 increased the pressure on the GCC to perform, and has collaborated wherever possible
11 to stimulate greater productivity and production (Transcript Pages 5579 to 5582). Some
12 of these areas include:

- 13
- 14 • Contractor's management of the trades;
 - 15 • Travel logistics for the contractor's workforce;
 - 16 • Site wide respectful workplace campaign;
 - 17 • Contractor's revised organizational structure and increased supervision capacity and
18 experience;
 - 19 • The development of an effective monitoring and control system to provide daily
20 feedback to contractor workforce;
 - 21 • Combining and streamlining BBE's and Manitoba Hydro's quality control and
22 assurance teams and processes;
 - 23 • Establishment of single mission and team ethics for the Manitoba Hydro and BBE
24 teams.

25
26 Manitoba Hydro has also been leading efforts to gain efficiencies, improve
27 methods/processes and achieve cost and schedule savings. A few examples of key
28 initiatives where Manitoba Hydro spearheaded efforts that led to significant cost and/or
29 schedule benefits:

- 30
- 31 • The decision to procure a new draft tube formwork system to utilize on the
32 remaining 5 units (Page 20 of Exhibit MH–117). This decision shortened the schedule
33 to install the bottom portion of the water passage referred to as the draft tube and
34 improved overall cost and schedule performance.

- 1 • The decision to utilize column extenders in the Powerhouse and Intake allowed for
2 structural steel to be installed in the concrete structures at lower elevations. This
3 installation provided an opportunity to enclose the Powerhouse and Service Bay
4 earlier resulting in a schedule savings of over 1 year (Transcript Page 5656).
- 5 • Advancement of the south dyke in 2018 and supporting design changes (Page 20 of
6 Exhibit MH-117). The advancement of the start of work on the south dyke will allow
7 for additional quantities to be placed during the winter 2018 and reduce risk to the
8 project schedule. (Pages 22 to 23 of Exhibit MH-117)

9
10 The 2018 plan, as noted on slide 72 of Exhibit MH-120, lists initiatives Manitoba Hydro
11 and BBE are undertaking to drive further improvement. One example is strategic winter
12 work being undertaken to allow for greater progress during the 2018 summer months
13 including advancing the South Dyke, and winter concrete work for the Powerhouse now
14 that it is enclosed (Exhibit MH-131 and Confidential Attachment).

15 16 **10.2.9 Summary on the Keeyask Project**

17 Manitoba Hydro is confident that the improvements from 2017 can continue and that
18 further improvement will take place in 2018. Manitoba Hydro has engaged external
19 experts to test Manitoba Hydro's and BBE's plans for 2018 to ensure everything is being
20 done to deliver the project at lowest cost and the shortest schedule (Transcript Page
21 5580).

22 23 **10.3 Bipole III Transmission Reliability Project**

24 The Bipole III Transmission Reliability Project is critical to increasing the reliability of the
25 HVDC system in Manitoba. Currently, approximately 70% of the Province's power is
26 generated in northern Manitoba and is delivered to southern Manitoba by the Bipole I
27 and Bipole II transmission lines which rest in the same right-of-way corridor and both
28 terminate at the Dorsey Converter Station. Bipole III will provide a separate transmission
29 corridor and termination point for the HVDC system

30
31 The Bipole III Transmission Reliability Project continues to be on schedule for a July 2018
32 in-service date and is on target to be completed within the \$5.04 Billion control budget
33 (Transcript Page 5595). As outlined by the PUB's Independent Expert Consultant MGF
34 Project Services, the Bipole III HVDC Converter Stations are well managed by Manitoba

1 Hydro and the potential for cost over-runs is low (Page 1 of Exhibit MGF-2R and Slide 28
2 of MGF's Presentation, Exhibit MGF-4).

3
4 Similarly, the Bipole III Transmission Line is well organized and efficiently managed. The
5 Project overall has used contracting strategies that were commercially astute and
6 allocated risk appropriately (Page 2 of Exhibit MGF-2R).

7
8 With approximately 6 months remaining until the in-service date, the remaining risks on
9 the Bipole III Transmission Reliability Project relate primarily to schedule. Performance
10 issues with one of the Transmission Line contractors have presented risks to the on-time
11 completion of the Transmission Line. However, Manitoba Hydro took "*immediate*
12 *action*" to mitigate this risk by removing scope from the under-performing contractor
13 and continues to closely monitor and manage schedule risks to ensure the July 2018 in-
14 service date is achieved. This was the right course of action, as attested to by MGF
15 (Transcript Pages 7202 to 7203).

16 17 **10.4 Manitoba-Minnesota Transmission Project**

18 The new 500 kV interconnection between Manitoba and Minnesota is a crucial part of
19 Manitoba Hydro's development plan to meet the future electricity needs of the
20 Province. The plan, at its core, includes the construction of the Keeyask Project, the
21 new interconnection, and several long-term firm export sales to the US and Canadian
22 utilities which will support the plan, and improve the economics, reliability and
23 robustness (Transcript Page 5604).

24
25 The Manitoba portion of the new interconnection is currently on schedule for an In-
26 Service Date of June 2020 and has a budget of \$453 million (Transcript Pages 5611 and
27 5619, and Page 2 of Exhibit MGF-2R). MMTP has had the benefit of using recent
28 costing and scheduling information from Bipole III and other smaller transmission line
29 projects in its scheduling, forecasting and budgeting processes, allowing it to provide a
30 current estimate at the P75 level (Transcript Page 5614).

31
32 Manitoba Hydro continues to manage the project appropriately and is committed to
33 continuing efforts to secure the June 2020 ISD (Transcript Page 5809). Further, the
34 Transmission Projects group is continually improving and adjusting how they perform
35 (Transcript Page 5614).

1
2 Manitoba Hydro's use of Primavera P6 for its scheduling activities is appropriate and
3 proven to be successful on several of its transmission line projects (Pages 52 to 54 of
4 Exhibit MH-117). Further, Manitoba Hydro's approach to tower design is appropriate
5 and cost effective (Pages 58 to 59 of Exhibit MH-117).

6
7 Manitoba Hydro's estimating methodology is consistent with industry standard (Page 2
8 of Exhibit MGF-2R). Manitoba Hydro will be updating the project estimate to include
9 awarded contracted values instead of estimates when those contract values become
10 available (Page 58 of Exhibit MH-117). While there are risks to both cost and schedule
11 as the Project is still at the pre-construction stage awaiting licensing and regulatory
12 conditions, the risks are being appropriately managed.

13 14 **10.5 Great Northern Transmission Line Project**

15 The U.S. portion of the new 500 kV interconnection between Manitoba and Minnesota
16 is on schedule for in-service on June 1, 2020. To date, the project is on budget with
17 approximately 10 percent of the funds spent. Manitoba has the expectation that the
18 Project will be under budget given the conservative nature of the Minnesota Power's
19 budgeting process (Transcript Page 5610).

20
21 The PUB's Independent Expert Consultant, MGF, reviewed the GNTL project. MGF
22 concluded (Page 163 of Exhibit MGF-2R):

23
24 *"The project is progressing, with Rights of Way being cleared, amongst other*
25 *activities. The Construction Management Agreement is well considered*
26 *commercially and serves to protect the interests of Manitoba Hydro. When*
27 *benchmarked with other similar projects, its cost estimate is considered high and*
28 *this should be reviewed in due course."*

29
30 Manitoba Hydro maintains that its estimates of costs included in the IFF associated with
31 GNTL are appropriate. Specific terrain conditions and weather dependency do impact
32 construction costs for the GNTL Project. As a large portion of the Right of Way is
33 through very remote and wet terrain, the Project is dependent on favourable winter
34 construction weather to minimize access costs. As a result, the Project has built an extra

1 year into the schedule to provide for the option of delaying work if a mild winter occurs
2 (Transcript Pages 5609 to 5610).

3
4 Further, as Minnesota Power has yet to finalize some of its contract costs, once those
5 contract costs are finalized, the budget will be updated to reflect market prices.

6
7 Given the challenging terrain conditions and the access related risk and associated
8 dependency on favourable weather conditions for construction and finally the fact that
9 construction is in its early stages with contracts remaining to be let, Manitoba Hydro
10 argues that the GNTL related costs that are included in its IFF are appropriate.
11 Consistent with MGF's recommendation, Manitoba Hydro will update the cost
12 assumptions in due course and those assumptions will be updated in future IFFs.

1 **11 12-YEAR VERSUS 20-YEAR DEBT TERMING STRATEGY**

2 As outlined in Manitoba Hydro’s Debt Management Strategy, filed as Appendix 3.5 to
3 the Application:

4
5 *Manitoba Hydro’s fundamental debt management objective is to provide*
6 *low cost, stable funding to meet the financial obligations and liquidity*
7 *needs of the Corporation, while maintaining risk at prudent levels and*
8 *reserving sufficient flexibility to adapt to changing circumstances.*
9

10 The potential cash flow stemming from cost reductions and the proposed rate increases
11 assumed in MH16 Update with Interim (filed as Appendix 3.8) provided an opportunity
12 for Manitoba Hydro to use the increase in forecasted cash flows to permanently retire
13 debt in the early 2020s when cash flow from operations is projected to exceed cash
14 required for investing activities. With the new forecast assumptions, there was an
15 opportunity for Manitoba Hydro to consider shortening the term to maturity of new
16 debt issuance, timing the maturity of new debt terms to coincide with periods in which
17 Manitoba Hydro would have cash available for debt repayment.
18

19 Historically, Manitoba Hydro’s interest rate forecast for Canadian borrowing has been
20 the average of 10 and 30 year Manitoba cost of borrowing, which Manitoba Hydro
21 called the 10 Yr+ rate. In the past, for forecasting purposes, Manitoba Hydro had
22 assumed a 20 year term to maturity for new Canadian dollar borrowing.
23

24 MH16 Update with Interim modeled a reduction of the Weighted Average Term to
25 Maturity (“WATM”) for new borrowing from 20 to 12 years. Using this assumption, the
26 forecast shifted approximately 30% of new debt issuance from the 30 year+ maturity
27 bracket to the under 10 year maturity bracket. The increased weighting was
28 predominantly in the 5 year term.
29

30 Matching expected surplus cash flows with maturing debt creates opportunity to avoid
31 refinancing risk by permanently reducing debt. Manitoba Hydro can capture interest
32 rate savings by borrowing more debt in the 5 year term as it is typically less costly than
33 30 year debt.
34

At the time of filing this General Rate Application (“GRA”), the new forecast modeled approximately \$500 million interest savings in the decade out to 2027. Providing all forecast assumptions held, including forecast rate increases, the planned level of interest rate risk would be kept at a manageable level. This would have permitted Manitoba Hydro to reduce the net 10 year borrowings to 2027 by \$4.2 billion. The following table (reproduced from Figure 1.9 of Manitoba Hydro’s Rebuttal Evidence, Exhibit MH-52) shows the total planned borrowing for the next decade comparing the scenario of Manitoba Hydro’s requested rate increases in MH16 Update with Interim with a 3.95% rate path.

Figure 11.1 MH16 Update with Interim under different rate increase scenarios

In Billions of Dollars

	IFF16U 7.9%	IFF16U 3.95%
2018-2022 Borrowing	\$ 13.5	\$ 14.1
2023-2027 Borrowing	\$ 8.8	\$ 9.7
2023-2027 Debt Retirement	\$ (3.1)	\$ (0.4)
Total 10 Year Borrowing	\$ 19.2	\$ 23.4

With higher rate increases, the MH16 Update with Interim generates more cash flow than under a 3.95% rate path. In the first five years of the forecast (2018-2022), this serves to modestly temper debt growth and borrowing needs as Manitoba Hydro borrows to complete Keeyask, Bipole III, GNTL and MMTP. In the second five years (2023 – 2027), the higher cash flows both limit new borrowing requirements and create surplus cash that can be used to pay down debt as it comes due instead of needing to refinance. Under the MH16 Update with Interim following the 7.9% rate path, Manitoba Hydro will borrow \$8.8 billion in the 2023-2027 timeframe, and therefore face refinancing risk on those borrowings. However, the plan assumes \$3.1 billion of cash flow that can be used to retire debt in that timeframe, leaving a net exposure of \$5.7 billion. Should the \$3.1 billion of cash flow not materialize as planned, the refinancing risk would increase. Even with the assumption of the 7.9% rate increases, a drought during this period could add \$1.5 billion to refinancing risk. Rising interest rates, depressed export prices, and/or a decrease in domestic load could impact cash flow, thereby further increasing refinancing risk. Increased capital costs and delays in the in-service date of Keeyask could add new debt borrowings into this timeframe further increasing interest rate risk.

1 The rate increase and debt management strategy proposed by Mr. Bowman in his
2 evidence would require the Corporation to borrow \$14.1 billion between 2018 and 2023
3 followed by an additional \$9.7 billion between 2023 and 2027. Prospective cash flow
4 would offer almost no relief to the borrowing need in the 2023 to 2027 period.

5
6 Placing over \$9 billion of refinancing risk into the 2023-2027 timeframe in the absence
7 of any prospective cash flow is, in Manitoba Hydro's informed judgement, too risky.
8 Even without adverse events or forecast error, it would increase the debt exposed to
9 refinancing risk by over 60% (\$5.7 billion vs. \$9.3 billion) in the period immediately after
10 Keeyask enters service, and results in effectively 100% of Manitoba Hydro's debt being
11 exposed to interest rate risk in the next decade. This strategy is inconsistent with past
12 debt strategies with the 3.95% rate path. Both NFAT scenario 5/6 and IFF15 had much
13 lower levels of refinancing risk immediately following the in-service of Keeyask. If
14 Manitoba Hydro has no reasonable prospect of cash flow and de-leveraging, prudence
15 dictates that it must shift its debt strategy toward longer dated maturities in order to
16 protect its ratepayers from unexpected interest rate movements for longer.

17
18 MH16 Update with Interim showed savings of approximately \$500 million due to
19 lowering the WATM of new debt issuance from 20 years to 12 years. However, this was
20 predicated on an interest rate forecast which had an upward sloping yield curve with
21 approximately 160 basis points between the all-in borrowing cost for a 5 year Province
22 of Manitoba bond and a 30 year Province of Manitoba bond. However, as noted by Ms
23 Stephen (Transcript Pages 1025 - 1026) Manitoba Hydro will adjust its debt
24 management strategy based on changing market conditions. This is inclusive of the yield
25 curve flattening as has been the case since the Bank of Canada began raising interest
26 rates in July 2017. As at the beginning of December 2017, the yield curve had flattened
27 such that there were approximately 90 basis points between the all-in borrowing cost
28 for a 5 year Province of Manitoba bond and a 30 year Province of Manitoba bond. Based
29 on that differential, the savings over the next 10 years under MH16 Update with Interim
30 erode to under \$250 million from adjusting the WATM for new debt issuance from 20 to
31 12 years.

32
33 Currently, the yield curve has flattened even further thus reducing the savings even
34 further. This is a market risk similar to rising interest rates. Interest rates are still at
35 historical lows, however, the Bank of Canada has raised interest rates three times since

1 July 2017 and will likely raise rates again in 2018. The current all-in borrowing cost for a
2 5 year Province of Manitoba bond is already exceeding the interest rate forecast used in
3 MH16 Update with Interim. If interest rates increase 1% over Manitoba Hydro's forecast
4 levels, the additional \$4 billion of exposed debt under the 3.95% rate path (Transcript
5 Page 703) would cost the Corporation an additional \$40 million per year. There is
6 potential over the 10 year period for the cost due to the rise in interest rates to exceed
7 the savings from adjusting the terming from 20 to 12 years. Without the ability to
8 generate sufficient cash to retire debt in the next 10 years, as would be the case under a
9 3.95% rate path, it would be imprudent to reduce the WATM to 12 years. Manitoba
10 Hydro will monitor the spread between 5 and 30 year debt and the available cash to
11 retire debt to determine and capitalize on any potential benefits available to ratepayers
12 in adjusting the WATM of new debt issuance.

1 **12 NO SAVINGS TO BE FOUND IN OPERATING AND MAINTENANCE EXPENSE**

2 Manitoba Hydro has implemented effective cost reduction measures including an
3 accelerated cost reduction plan to minimize growth in Operating & Administrative costs
4 (“O&A”). These measures have resulted in a growth in O&A costs at or below inflation
5 since 2009/10. As demonstrated on page 35 of Manitoba Hydro’s Rebuttal Evidence
6 (Exhibit MH-52), the corporation will achieve a 1.8% annual decrease in O&A over the 5
7 year period from 2014/15 to 2018/19, well below Manitoba CPI. To achieve this level of
8 savings, Manitoba Hydro has eliminated over 400 operating positions between 2014/15
9 and 2016/17 and will be further streamlining its workforce by eliminating 900 staff of
10 which approximately 700 are anticipated to be operational in nature. The 900 person
11 staff reduction will be achieved primarily through the implementation of a Voluntary
12 Departure Program (“VDP”) which was launched in April 2017 in addition to a 30%
13 reduction in Executive as well as a 40% reduction in senior management. The following
14 table (**Figure 12.1**) summarizes the staffing reductions achieved since 2014/15 including
15 the results of the VDP by each Corporate/Operating group.
16

17 **Figure 12.1 Workforce Reduction Plan**

	Achieved	Current Committed	Total
	2014/15 - 2016/17	Reductions	Reductions
President & CEO	4	1	5
General Counsel & Corporate Secretary	2	5	7
Human Resources & Corporate Services	77	147	224
Indigenous Relations	10	9	19
Finance & Strategy	13	33	46
Generation & Wholesale	105	157	262
Transmission	115	198	313
Marketing & Customer Service	103	267	370
Total	429	817	1 246

18 **Source: Page 35 of Exhibit MH-68**

19
20
21 In addition to position reductions, Manitoba Hydro has committed to achieve
22 procurement savings through supply chain management initiatives (as outlined in the
23 response to Coalition/MH I-108b). As indicated in the response to Coalition/MH I-107b,
24 to date Manitoba Hydro has achieved savings of approximately \$8 million with
25 estimated future annual cost savings between \$20 and \$50 million over the 5 year

1 period 2017/18 through 2021/22 (approximately 70% related to capital and the
2 remaining 30% to operational savings).

3
4 Mr. Bowman's evidence (Exhibit MIPUG-13) on page 6-5 on lines 27 to 29 states "...the
5 utility has not even achieved a level of O&A that is as low as simple inflation since the
6 2011/12 year." The O&A figures used as the basis for Figure 6-2 on page 6-4 of Mr.
7 Bowman's evidence were provided in the response to MH-MIPUG (BOWMAN)-18, and
8 do not take into consideration the impact of significant accounting changes that were
9 implemented over the period 2009/10 to 2013/14 in support of the Corporation's
10 transition to IFRS.

11
12 As shown in **Figure 12.2** below, Manitoba Hydro recognized approximately \$37 million
13 of accounting changes in 2011/12 which increased to \$91 million by 2013/14. The
14 majority of the changes were a result of aligning the corporation's capitalization policies
15 with other Canadian utilities and are not indicative of a change in the costs to operate
16 the corporation; rather they are a change in the accounting treatment of such costs and
17 should be excluded from any analysis of year over year growth in O&A expenditures.

18
19 **Figure 12.2 Summary of Accounting Changes Under CGAAP**

Summary of Accounting Changes Under CGAAP					
<i>(in thousands of dollars)</i>					
	<u>2009/10</u>	<u>2010/11</u>	<u>2011/12</u>	<u>2012/13</u>	<u>2013/14</u>
Reduction to Overhead Costs Capitalized	9 100	28 727	29 302	60 180	61 384
Intangible Assets - Costs Ineligible for Capitalization	4 080	4 162	4 245	4 330	4 416
Pension & Benefits - Discount Rate changes	0	0	3 032	13 835	25 355
Total	13 180	32 889	36 579	78 345	91 155

20
21 **Source: Page 36 of Exhibit MH-52**

22
23 On page 52 of its evidence (Exhibit GSS/GSM-9), London Economics International ("LEI")
24 recommends that Manitoba Hydro's request for a rate increase should be held in
25 abeyance until several analysis is performed. Manitoba Hydro is concerned by such a
26 recommendation given that in LEI's response to MH/LEI 1-11b, they confirm their
27 analysis was only illustrative in nature and "... that more detailed evidence on Manitoba
28 Hydro relative productivity would be an important consideration in determining the
29 appropriateness of Manitoba Hydro's operating costs." This point is further confirmed in
30 LEI's oral testimony (Transcript pages 6820 and 6821):

1
2 *Ms. Patti Ramage: But—okay. The metrics you’ve provided in your report are not*
3 *the type of metrics that would tell us whether Manitoba Hydro is achieving*
4 *operating efficiencies, correct? We would have to do more than your report?*

5
6 *Mr. A. J. Goulding: I—I believe that we’ve acknowledged that in our report,*
7 *that—that more would need to be done.*

8
9 As stated on page 37 of Manitoba Hydro’s Rebuttal Evidence (Exhibit MH-52):

10
11 *Manitoba Hydro is also concerned with the key performance indicators (“KPI”)*
12 *used by LEI (page 45) in their comparison of the Corporation’s operational*
13 *efficiency with other utilities. Each of the KPIs measure the output per employee;*
14 *however there is no information as to whether the utilities’ employee bases are*
15 *comparable in nature to Manitoba Hydro.*

16
17 In addition, several of the metrics selected by LEI will improve instantaneously the
18 moment Keeyask comes in-service (Transcript page 6819) which demonstrates the
19 hazards of making conclusions based on arbitrarily selected metrics when dealing with a
20 complex business such as that of Manitoba Hydro and the need to approach such
21 analysis with caution. Manitoba Hydro notes that vertically integrated utilities are large
22 complex organizations whose operations are influenced by a myriad of factors including
23 political (provincial, federal and international) and regulatory influences, landscape,
24 weather, provincial economics (employment levels, labour rates, inflation, etc.),
25 financial markets, age of assets, type of supply (hydro vs. coal), location of supply,
26 technology, etc. Because of the extensive number influences over the operations of a
27 utility, comparisons (e.g. KPIs) amongst utilities are often limited to providing a surface
28 analysis at best as the underlying reasons for differences are typically comprised of a
29 number of different factors where the impact of any one factor is not specifically
30 measurable. The complexity associated with comparing utilities to one another is
31 discussed by Mr. Yatchew on Transcript pages 4475 and 4476 of his testimony as he
32 states:

33
34 *I mean for Manitoba Hydro to actually try to compare itself to other utilities, not*
35 *on the outcomes, but really on the cost side, is a fairly-its-it’s a-it’s a fairly*

1 *challenging exercise because of its unique characteristics. That falls under the*
2 *rubric of benchmarking, and benchmarking is a complicated process, and its*
3 *always an evolving process.*

4
5 The metrics presented by LEI in no way assist in assessing whether the Corporation is
6 achieving operational efficiencies and does not provide any conclusive evidence to
7 justify the abeyance of the requested rate increase. Further, the analysis does not
8 provide justification that a more in-depth analysis/comparison of Manitoba Hydro's
9 operations is required. Based on the actual and projected reductions to operating costs,
10 Manitoba Hydro can demonstrate that the Corporation has taken aggressive cost
11 reduction measures. The end stage of a Voluntary Departure Program involving the
12 elimination of roughly 900 positions, where functions have been eliminated, jobs
13 combined, departments dismantled and redistributed and operating costs have been
14 reduced significantly is not the time to embark on a time consuming and costly
15 benchmarking exercise. A more detailed review will only result in an increase in
16 consulting costs to be borne by the ratepayer while providing limited value in terms of
17 assessing the efficiency of Manitoba Hydro in comparison to other utilities.

1 **13 IMPACT ON MANITOBA ECONOMY**

2 **13.1 Job Creation**

3 Dr. Janice Compton and Dr. Wayne Simpson are correct in concluding that where the
4 additional revenues received by Manitoba Hydro through a rate increase are all sent, in turn,
5 by Manitoba Hydro to creditors outside Manitoba to pay interest and principal on debt, a
6 consequence will likely be that fewer jobs will be created in Manitoba. There will be less
7 money circulating in the Manitoba economy (Page 3 of Dr. Janice Compton and Dr. Wayne
8 Simpson’s Evidence filed on behalf of the Consumer’s Coalition, Exhibit Consumer’s Coalition
9 CC-18). London Economics International (“LEI”) gave the same conclusion, though its
10 employees used a different model than did Drs. Compton and Simpson.

11
12 The precise impact on job creation, however, of a rate increase of 7.9% for one year
13 commencing on April 1, 2018 is debateable. Drs. Compton and Simpson used a simple model
14 to estimate the impact of the rate increase and acknowledged that their model did not take
15 into account that as some firms choose not to hire, or to decrease their labour force, in
16 response to a price increase in electricity, the supply of labour in the market place will
17 increase (Transcript Pages 4650 to 4655). Other firms will react to an increase in the supply
18 of labour, and the corresponding downward pressure on wages, to hire more labour. This, in
19 turn, will modify the negative impact on job creation of an increase in the price of electricity
20 where one assumes that the entire revenue raised from the price increase leaves the
21 Province. Further, Drs. Compton and Simpson acknowledged that their model did not take
22 into account that to the extent that there is an increase in the number of unemployed
23 persons as some firms cut back their labour force, there is an increase in money coming into
24 the Province in the form of Employment Income payments from the federal government.
25 This increase in funds flowing into Manitoba will offset to an extent the flow of funds being
26 sent out of Manitoba by Manitoba Hydro to pay its debt.

27
28 In their initial work, Drs. Compton and Simpson also ignored that some residential
29 customers, as many as 70 per cent of Manitoba’s residential customers, have the option of
30 reducing the amount they save each year in order to pay for an increase in their electricity
31 bills as opposed to cutting back their spending on other goods and services (Transcript Page
32 4795). Similarly, some businesses have the option of paying for an increase in their electricity
33 bills by drawing on their tax deferral accounts, as opposed to passing on such increase in
34 their prices, reducing their profits or reducing their purchases of other commodities used in
35 their businesses. These facts will also modify the impact to Manitoba’s economy of an

1 increase in electricity rates because they result in a more modest reduction to the overall
2 amount of money circulating in the Province.

3
4 LEI's effort to "illustrate" the impact of an increase in the price of electricity on hog, dairy
5 and potato farms, convenience stores and hotels was undermined by its misuse of Manitoba
6 agricultural data that was itself imprecise and intended only as an "illustrative" guide to
7 farmers for budgeting purposes and by a puzzling decision to rely upon American data for
8 convenience stores and hotels in that country (Transcripts Pages 6828 to 6838 and 6856 to
9 6857). Dr. Adonis Yatchew, like Drs. Compton and Simpson, relied upon Canadian sources,
10 primarily Statistics Canada, and Appendix 4 of Dr. Adonis Yatchew Report, filed on behalf of
11 the Public Utilities Board of Manitoba, Exhibit AY-1, sets out over some three pages the
12 proportion that electricity bears in the costs of the industries and business in Manitoba's
13 economy. With the exception of six industries, electricity is less than five per cent, in many
14 cases less than one percent, of the cost of doing business. An increase in the price of
15 electricity of 7.9% on April 1, 2018 will have a far more modest impact on these businesses
16 than an increase in price in a host of other commodities that they buy, a change in the
17 exchange rate or, most significantly, an increase in interest rates. Indeed, Dr. Yatchew
18 observed on slide 53 of Dr. Adonis Yatchew Presentation, Exhibit AY-2, "about 60% of
19 Manitoba energy is from hydrocarbons". Although this compares very favourably with the
20 rest of Canada, it nonetheless reveals that Manitoba's economy continues to be far more
21 vulnerable to the impacts of an increase in the price of hydrocarbons than it is to the impact
22 of an increase in the price of electricity.

23
24 One must also avoid confusing slower job creation following an increase in the price of
25 electricity where, to repeat, one assumes that all of the revenue raised through the price
26 increase leaves the Province, with a decline in the growth of Manitoba's economy. Since
27 2009, the price of electricity in Ontario has grown by 50 per cent (Slide 43 of Exhibit AY-2),
28 well in excess of the proposed rate increase of 7.9% to commence April 1, 2018.
29 Notwithstanding a much larger increase, Ontario's economy has continued to grow.

30
31 At worst, an increase in the price of electricity of 7.9% on April 1, 2018 might lead to
32 something less than 80 fewer jobs than there otherwise might be (Undertaking 51, Exhibit
33 CC-51)

1 The evidence presented on job creation is helpful in understanding the impact to Manitoba's
2 economy that ultimately follows from the borrowing of many billions of dollars. Drs.
3 Comptom and Simpson, to repeat, concluded as the basis of their analysis that money that
4 leaves Manitoba to pay debt is taken out of circulation and this has a negative impact on the
5 Province's economy, in particular on job creation (Transcript Pages 4650 to 4655). The more
6 money that Manitoba Hydro is compelled to borrow to meet its day to day operating costs,
7 estimated to be another one billion dollars in the absence of rate increases, will lead to more
8 money leaving Manitoba in the future. If one wants to give priority to job creation, as is done
9 by governments in the face of serious recessions, and accepts that it is necessary to borrow
10 billions of dollars to facilitate job creation, such borrowing is best done by government.
11 Government can best allocate such borrowing directly to businesses and jobs that will at
12 least create infrastructure to improve the lives of the taxpayers who, in due course, will have
13 to pay the cost of the borrowing. Leaving Manitoba Hydro in a position where it must borrow
14 another billion dollars in order to operate, as distinct from creating new infrastructure,
15 because it will avoid in the near term a negative influence on job creation is a clumsy and
16 inappropriate use of a utility's ability to borrow. And, such borrowing effectively leaves the
17 utility's rate payers, in the long term, with no discernable benefit, other than the knowledge
18 that generally, with no rate increase, there was no negative impact on job creation that can
19 be attributed to electricity rates. And leaving Manitoba Hydro in a position where it is
20 compelled to borrow large sums just to operate is particularly ill-advised when such a course
21 of action increases the risk of a down-grade in the credit rating of the Province of Manitoba
22 (and of Manitoba Hydro). This immediately results in even more dollars being removed from
23 circulation within Manitoba and being sent to creditors outside the Province with the same
24 negative consequences to job creation and Manitoba's economy identified by Drs. Compton
25 and Simpson and the employees of LEI.

26
27 Manitoba Hydro has created and is creating thousands of jobs through the borrowing it has
28 and is doing to create new infrastructure, namely the Keeyask Project and Bipole III. Leaving
29 it to borrow more in the near term so that jobs, in theory, may be created in other sectors of
30 the economy, or not be lost, is ill- advised. Better to avoid such borrowing, pay back as
31 quickly as feasible what has been borrowed and look at a future in which increases in
32 electricity rate can match the rate of inflation and, in the long term less money will leave the
33 Province through the payment of debt and remain to create jobs.

1 **13.2 City of Winnipeg**

2 The City of Winnipeg’s Economist Tyler Markowsky attempted to quantify the increased
3 direct and indirect electric utility cost to the City of Winnipeg over the next 20 years,
4 assuming all rate increases in MH16 Update were approved. This evidence has demonstrated
5 a series of unrealistic and oversimplified assumptions. Manitoba Hydro therefore submits
6 that the PUB should give little weight to the conclusions advanced by the City of Winnipeg in
7 this evidence.

8
9 Section 5 of Manitoba Hydro’s Written Rebuttal Evidence, Exhibit MH-52, outlines several
10 serious flaws in the financial analysis offered by the City of Winnipeg. Further, Mr.
11 Markowsky admitted that the analysis includes not only the proposed rate increases which
12 form the subject of this Application, but all indicative rate increases in MH16 Update
13 (Transcript Page 6490); assumed no price elasticity (Transcript Page 6520); did not consider
14 rate class, demand charges, or basic monthly charges (Transcript Page 6522); was not
15 weather-adjusted (Transcript Page 6527); and that Mr. Markowsky had not made enquiries
16 to ensure that the charges which formed the basis of his calculations did not include
17 unrelated fees for licenses or miscellaneous billings (Transcript Pages 6525 to 6526).

18
19 Mr. Markowsky’s decision to exclude the effects of price elasticity or the effects of energy
20 conservation in extrapolating growth in consumption is an unrealistic assumption that
21 results in a potentially significant overestimate of future costs to be borne by the City of
22 Winnipeg. Manitoba Hydro has provided technical and financial assistance to the City of
23 Winnipeg for in the order of 150 Power Smart projects, many of which are still in progress.
24 Furthermore, Manitoba Hydro has embarked on a program to replace all streetlights with
25 new high efficiency LED luminaires. Power Smart projects, the replacement and retrofitting
26 of aging building stock and replacement of existing street lamps with high efficiency LED
27 luminaires are factors which impact consumption and consumption patterns (Exhibit MH-
28 52). It is therefore not reasonable to disregard the effects of energy conservation on
29 electricity costs over the period of 2017 to 2037. Even by Mr. Markowsky’s own admission,
30 “it’s not a – a perfectly precise analysis” (Transcript Page 6523).

31
32 In considering the impact of the Application presently before the PUB, Mr. Markowsky
33 calculated the impact to the City of Winnipeg for 2019 to be \$721,000. While this figure
34 suffers from the imprecision noted above, it is worthy to note that this amount represents
35 only 0.06% of the City of Winnipeg’s projected budget expenditures for the same year

1 (Transcript Page 6535). Manitoba Hydro does not dispute that the City of Winnipeg's
2 finances may be impacted by an increase in electricity rates, but submits that the City of
3 Winnipeg is in a better position than most ratepayers recognizing that they receive
4 Electricity Tax revenue calculated as a percentage of Winnipeg residents total electricity bills,
5 and are able to recover net cost increases by increasing revenues through taxes, fees and
6 other charges imposed by the City of Winnipeg. Given the significant flaws inherent in his
7 analysis, Manitoba Hydro submits that the conclusions of Mr. Markowsky's analysis should
8 be afforded very little, if any, weight in considering the impact of the requested rate increase
9 on the City of Winnipeg.

1 **14 MANITOBA HYDRO IS COMMITTED TO WORK WITH STAKEHOLDERS TO DEVELOP**
2 **APPROPRIATE AND COST EFFECTIVE SOLUTIONS THAT WILL ADDRESS CHALLENGES OF**
3 **LOW INCOME AND AFFORDABILITY**

4 **14.1 Income Sufficiency and Energy Poverty are Complex Issues**

5 Manitoba Hydro is of the view that the issue of affordability of energy, like any other
6 essential items such as food and housing, extends beyond considerations associated
7 with electricity price increases.

8
9 Issues of poverty and distributional effects are complex and ought to be addressed
10 through the setting of social policy which is within the purview of government. As such,
11 Manitoba Hydro is of the view that of the provision of social assistance programs
12 directed to low income customers is appropriately reserved for the Province of
13 Manitoba.

14
15 As discussed in Tab 7 of the Application, Manitoba Hydro offers programs to assist
16 customers in managing their energy consumption through the implementation of
17 energy efficiency opportunities in their homes and businesses. Moreover, to assist low-
18 income customers, Manitoba Hydro continues to provide targeted and enhanced
19 support through its Affordable Energy Program, to improve the energy efficiency of their
20 homes resulting in lower energy bills and increased comfort.

21
22 Manitoba Hydro actively participated in the Bill Affordability Stakeholder Engagement
23 Process undertaken in 2016 to review existing initiatives and explore potential
24 alternatives to further address bill affordability for Manitobans. Manitoba Hydro's
25 existing suite of bill affordability initiatives includes the Affordable Energy Program,
26 Neighbours Helping Neighbours Program and Bill Accommodation practices. These
27 initiatives were reviewed by stakeholders in the collaborative process and
28 enhancements were suggested to further increase assistance to lower income
29 customers. Manitoba Hydro will enhance, where appropriate, its programs and
30 processes to assist low-income customers.

31
32 The work of Bill Affordability Collaborative Group shed light on how difficult it can be at
33 first instance to even define energy poverty and how complex it can be to administer an
34 income based program.

1 Two of the key findings from the Bill Affordability Collaborative Process is that energy
2 poverty is not a prime cause of arrears (Transcript Page 2326) which indicates those
3 experiencing energy poverty may not necessarily struggle with their energy bills and the
4 relationship between consumption and income is very low (Transcript Page 2328).

5
6 Manitoba Hydro's administration of the Affordable Energy Program, which is income
7 based, is no stranger to the challenges of obtaining income information (Transcript
8 Pages 2512 to 2513). As noted by Dr. Mason in his testimony, "...there's a certain
9 number of people who will not actually reveal their income..." (Transcript Page 2325).

10
11 At Transcript Pages 2526 and 2527, Dr. Mason was asked about overcoming the issues
12 identified with implementing a low income rate, and in his reply, he suggests that
13 existing government social programs should be modified to address the issue:

14
15 *"I think in my view, which is looking at how the – the resources that would be*
16 *needed to do this, my view is that much closer cooperation with the provincial*
17 *government and the existing programs, rent assist, social assistance or income*
18 *assistance would be the smart way to go.*

19
20 *I think if the Board were to kind of direct or sort of suggest that these programs*
21 *be adjusted and accommodate energy increases in the same way they*
22 *accommodate inflationary increases that would be, I think, the most direct way*
23 *and cost efficient way to actually provide assistance."*

24
25 Dr. Mason raises another point for consideration in his discussion with Board Member
26 Grant at Transcript Pages 2545 to 2550, regarding the complications in targeting
27 recipients on the basis of low income, when they may not necessarily be low net worth
28 individuals:

29
30 *"We all talk about income, but we don't talk about wealth, and we have a lot of*
31 *wealthy poor people in the country, and they're called seniors. They have assets,*
32 *but they have low income, and that's very common.*

33
34 *"So throughout our lifespan, our income and our wealth fluctuate upon which*
35 *stage of our life cycle we're at. And so designing policies that apply to people at*

1 *various stages of their income and wealth life cycle is very tricky. But you know, I*
2 *think most Canadians would accept the fact that an income-tested program that*
3 *referenced income tax data is probably still the best way to go, but we're going*
4 *to always have to deal with these anomalies where we fund people under these*
5 *programs who happen to be living in a household of relatively well-off people.*
6 *So, I mean, targeting is always going to be a problem."*

7
8 *"And that's why I come back is that we have specialists in our society that do*
9 *that. They're called income assistance people who work for the provincial*
10 *government. Building a separate expertise in Manitoba Hydro is going to be*
11 *quite complex, and you're just never going to get it right."*

12
13 These findings and difficulties with the administration, implementation and on-going
14 operation of a rate assistance program pose significant challenges in identifying which
15 customers truly require assistance and point to the need for further exploration to
16 ensure any assistance mechanism best addresses the intended need.

17
18 Dr. Mason summarizes this in his testimony at Transcript Page 2335 by stating,

19
20 *"...running an income assistance program is extremely complicated and it's high*
21 *cost and it requires a whole range of expertise that is typically not embedded*
22 *within Hydro. It's typically embedded within the income assistance programs of*
23 *the province, which have better access to information. So, the whole caution*
24 *that I want to encourage, the Board needs to be careful in directing Manitoba*
25 *Hydro to apply rate relief based upon an income test. The argument here is that*
26 *Manitoba Hydro does not have nor is it likely to obtain critical information that*
27 *will allow it to target rate support programs accurately. Manitoba Hydro is not*
28 *currently equipped and is unlikely to run income tested program effectively."*

29
30 Manitoba Hydro does not have the resources to administer a new income-based
31 program nor does it have access to pertinent data, such as income of its customers, to
32 successfully implement such a program. The Provincial Government of Manitoba already
33 administers income based programs, has the resources and provides these programs
34 through a variety of existing mechanisms noted in the report of the Bill Affordability
35 Collaborative Process.

1
2 Manitoba Hydro's position has and continues to be any deviation from standard rate
3 setting such as a special rate design for a specific customer rate class is a social policy
4 issue to be funded by Government. Mr. Raphals agrees with this principal as noted on
5 page 10 of his evidence on behalf of the Assemble of Manitoba Chiefs, Exhibit AMC-7-1,
6

7 *"Since the affordability program should be designed to ensure energy security for*
8 *those unable to cope with rising energy costs, however, funding from all*
9 *taxpayers rather than simply higher income ratepayers or dedicated fees seems*
10 *most appropriate, much as other income security programs such as Manitoba's*
11 *Employment and Income Assistance are financed from general revenues."*
12

13 **14.2 Manitoba Hydro's Role in Addressing Affordability Issues**

14 Mr. Shepherd testified in his direct evidence presentation (Exhibit MH-64) on the
15 perspectives of Manitoba Hydro on broader societal issues of energy poverty and
16 economic competitiveness. At Transcript Pages 135 to 137, he states:
17

18 *"Questions of income and energy poverty and economic competitiveness are*
19 *certainly important and ones we have considered to the degree we can. But*
20 *these are really issues of broad public policy and cannot easily be resolved*
21 *through a rate-setting process. The responsibilities and tools for such matters do*
22 *not rest with Manitoba Hydro or the Public Utilities Board.*
23

24 *Manitoba Hydro has always worked and will continue to work with all*
25 *stakeholders on these kinds of issues, and will seek to play a positive role in*
26 *solutions that improve the economic conditions for all Manitobans. But income*
27 *adequacy and economic development issues are mostly beyond Manitoba*
28 *Hydro's mandate or control. We cannot and should need not use this rate-*
29 *setting hearing to do the work of developing and implementing public social*
30 *policies. We are not well-equipped to handle these issues and the potential*
31 *consequence of trying to do so is compromising both the financial integrity of the*
32 *utility and ultimately making decisions that result in the transfer of costs from*
33 *some groups of customers to other customers.*
34

1 *I believe these issues are best left to government, who are responsible for*
2 *establishing the appropriate policy framework and directives for both Manitoba*
3 *Hydro and this Board to follow.”*
4

5 **14.3 Legal Issues to be Considered**

6 Manitoba Hydro is aware that in Public Utilities Board of Manitoba (“PUB”) Order 73/15,
7 the PUB noted on page 28 that the PUB remained of the view, consistent with the
8 findings in Order 116/08, that it had the jurisdiction to order the implementation of a
9 bill affordability program. Manitoba Hydro’s legal position on the issue has not changed
10 since the last GRA. In our respectful view, there is a serious jurisdictional question, and
11 concern that the PUB’s conclusion in Order 73/15 cannot be reconciled with the current
12 statutes in Manitoba. This jurisdictional issue remains untested in the court in
13 Manitoba.
14

15 Manitoba Hydro submits that the PUB, ought to reconsider the issue and as such has set
16 forth its legal position on the matter below. It is noteworthy that while the Nova Scotia
17 Court of Appeal decision was raised in argument during the 2014/15 GRA, the PUB
18 declined to provide reasons in Order 73/15 as to why this decision was not considered
19 or applied. Furthermore, this issue has been considered in two additional Canadian
20 jurisdictions, British Columbia and Alberta. Manitoba Hydro submits that the decisions
21 of these two regulatory authorities are persuasive and ought to be considered.
22

23 As an administrative tribunal, the PUB is not bound by the concept of stare decisis - it is
24 not obliged to follow its own previous decisions on similar issues. An administrative
25 decision maker has the capacity to determine the scope of his or her own jurisdiction.
26 The determination of an administrative tribunal’s jurisdiction is a question of statutory
27 interpretation.⁸ The object of statutory interpretation is to *“seek the intent of*
28 *Parliament by reading the words of the provision in their entire context and according to*
29 *their grammatical and ordinary sense, harmoniously with the scheme and object of the*
30 *Act and the intention of the legislature”*.⁹ While the jurisprudence is clear that a broad,
31 liberal and purposive approach should be taken to statutory interpretation, Canadian
32 courts have repeatedly cautioned that *“a liberal and purposive interpretation cannot*

⁸ *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraph 33.

⁹ *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraph 33.

1 *supplant a textual and contextual analysis simply in order to give effect to a policy*
2 *decision different from the one made by Parliament.”¹⁰*

3
4 The PUB derives its jurisdiction to review Manitoba Hydro rates from section 25(1) of
5 *The Crown Corporations Governance and Accountability Act* which provides as follows:

6
7 25(1) Despite any other Act or law, rates for services provided by Manitoba
8 Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The
9 Public Utilities Board under The Public Utilities Board Act and no change in rates
10 for services shall be made and no new rates for services shall be introduced
11 without the approval of The Public Utilities Board.

12
13 Section 25(4) of *The Crown Corporations Governance and Accountability Act* contains a
14 list of factors which the PUB may consider in a rate review application. None of those
15 factors expressly permit the PUB to consider affordability or customers’ ability to pay. It
16 is worth noting that of the nine factors set out in section 25(4)(a), seven relate to
17 Manitoba Hydro’s fiscal needs. The remaining two factors permit the PUB to consider
18 any “*compelling policy consideration*” or “*any other factor*” that the PUB may consider
19 relevant to the rate for services application before it. When read in isolation paragraphs
20 25(4)(a)(viii) and (ix) are vague and expansive. However, the PUB does not have limitless
21 discretion to consider any factor it chooses. The grant of discretion must be interpreted
22 within the context of Part IV of *The Crown Corporations Governance and Accountability*
23 *Act* and the entire statutory scheme relating to the price for supply of power, and the
24 PUB’s primarily role to set just and reasonable rates.¹¹

25
26 Subsection 39 of *The Manitoba Hydro Act* is germane to the issue. The Act states:

27
28 Price of power sold by corporation

¹⁰ *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraph 62; also see *Gould v. Yukon Order of Pioneers*, [1996] 1 S.C.R. 571 at paragraph 50 per Forest, J concurring; *Placer Dome Canada Ltd. v. Ontario (Minister of Finance)*, 2006 SCC 20 at paragraph 23.

¹¹ See *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 at paragraph 47 wherein the Supreme Court of Canada considered the jurisdiction of a utilities regulator to impose any condition in an order that was necessary for the public interest. The Court held “These provision on their own are vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to an order it makes. Furthermore, the concept of “public interest” found in s. 15(3) is very wide and elastic; the Board cannot be given total discretion over its limitations”.

1 39(1) The prices payable for power supplied by the corporation shall be such
2 as to return to it in full the cost to the corporation, of supplying the power,
3 including

4 (a) the necessary operating expenses of the corporation, including the cost of
5 generating, purchasing, distributing, and supplying power and of operating,
6 maintaining, repairing, and insuring the property and works of the corporation,
7 and its costs of administration;

8 (b) all interest and debt service charges payable by the corporation upon, or in
9 respect of, money advanced to or borrowed by, and all obligations assumed by,
10 or the responsibility for the performance or implementation of which is an
11 obligation of the corporation and used in or for the construction, purchase,
12 acquisition, or operation, of the property and works of the corporation, including
13 its working capital, less however the amount of any interest that it may collect
14 on moneys owing to it;

15 (c) the sum that, in the opinion of the board, should be provided in each year for
16 the reserves or funds to be established and maintained pursuant to
17 subsection 40(1).

18
19 Fixing of price by corporation

20 39(2) Subject to Part 4 of *The Crown Corporations Governance and*
21 *Accountability Act* and to subsection (2.1), the corporation may fix the prices to
22 be charged for power supplied by the corporation.

23
24 Equalization of rates

25 39(2.1) The rates charged for power supplied to a class of grid customers
26 within the province shall be the same throughout the province.

27
28 Interpretation

29 39(2.2) For the purpose of subsection (2.1),

30 (a) grid customers are those who obtain power from the corporation's main
31 interconnected system for transmitting and distributing power in Manitoba; and

32 (b) customers shall not be classified based solely on the region of the province in
33 which they are located or on the population density of the area in which they are
34 located.

1 Simply put, the price charged for power must allow the Corporation to recover its costs
2 of supplying such power inclusive of certain specified business expenses. The rates
3 charged for power supplied to a class of grid customers must be the same throughout
4 the province, and customers must not be classified solely on their location or on the
5 population density of the area in which they are located.

6
7 Subsections 39(2.1) and (2.2) were enacted by *The Manitoba Hydro Amendment Act*, SM
8 2001, c 23. The purpose of this amendment was to ensure Manitoba Hydro charged a
9 consistent rate for all customers regardless of point of delivery. The amendment was
10 characterized as one of “*fundamental fairness*” with the aim to make “*uniform*
11 *electricity rates a reality in Manitoba and put everybody on an equal footing when it*
12 *comes to the rates charged for basic services.*”¹² The purpose of section 39(2.1) and (2.2)
13 was to create a “*single rate for residential hydro users*”.¹³

14
15 It is expected that parties to this proceeding may ask the PUB to implement a low
16 income program targeting First Nations living on reserves. Such a program would
17 necessarily classify customers based upon their geographic location within the Province
18 of Manitoba. Manitoba Hydro submits that a First Nations living on reserve class would
19 violate the express prohibition contained within subsection 39(2.2) of *The Manitoba*
20 *Hydro Act*.

21
22 The PUB’s rate setting function must also be interpreted having regard to Manitoba
23 Hydro’s mandate. Section 2 of *The Manitoba Hydro Act* provides that the purpose and
24 object of the Corporation is to provide for the supply of power adequate to meet the
25 province’s needs and to promote economy and efficiency in all matters related to the
26 generation, transmission, distribution and use of power. Subsection 43(3) states the
27 Corporation’s funds shall not be employed for the purposes of the government or any
28 government agency. Accordingly, the only appropriate use for Manitoba Hydro funds
29 are the legitimate purposes set out in section 2.

¹² Legislative Assembly of Manitoba, Debates and Proceedings, 2nd Session 37th Legislature, May 30, 2001 at page 2505 (Hon. Greg Selinger). Found as **Appendix 14.1** to this Section.

¹³ Legislative Assembly of Manitoba, Debates and Proceedings, 2nd Session 37th Legislature, May 30, 2001 at page 2505 (Hon. Greg Selinger).

1 Manitoba Hydro does not have a mandate, either express or implied, to engage in social
2 programming. The bill affordability programs discussed by some Interveners during the
3 evidentiary portion of the hearing aim to mitigate existing social inequities through rate
4 setting. While such a goal is laudable, it falls outside Manitoba Hydro's stated mandate.
5 Manitoba Hydro respectfully submits that absent express language to the contrary, the
6 PUB cannot, through its rate setting function, expand the mandate and purpose of
7 Manitoba Hydro.

8
9 The PUB's jurisdiction is expressly limited to the approval of rates which appropriately
10 balance the interests of ratepayers and the financial health of the utility.¹⁴ *The Public*
11 *Utilities Board Act* applies to Manitoba Hydro only to the degree necessary to fulfill the
12 function set out in Part IV of *The Crown Corporations Governance and Accountability*
13 *Act*.

14
15 In Manitoba Hydro's respectful submission, the text, context and purpose of *The Crown*
16 *Corporations Governance and Accountability Act*, *The Manitoba Hydro Act* and *The*
17 *Public Utilities Board Act* clearly demonstrate that the PUB does not have the
18 jurisdiction to order the implementation of low income rates or other bill affordability
19 programs.

20
21 The Supreme Court of Canada held that only after a textual, contextual and purposive
22 approach reveals a genuine ambiguity, should a court resort to any subsidiary principles
23 of statutory interpretation, including consideration of constitutional values and other
24 external aids.¹⁵ Where there are two equally plausible interpretations, the
25 interpretation that complies with constitutional values will generally be preferred.
26 However, reliance upon the *Charter* as an interpretive aid cannot be used to defeat
27 clear legislative intent.¹⁶

¹⁴ *Manitoba Keewatinowi Okimakanak Inc. v. Manitoba Hydro-Electric Board*, 1992 CarswellMan 373 at paragraph 9 and *Consumers' Assn. of Canada (Manitoba) Inc. v. Manitoba Hydro Electric Board*, 2005 MBCA 55 at paragraphs 64-65.

¹⁵ *Bell ExpressVu Limited Partnership v. Rex*, 2002 SCC 42 at paragraphs 28 and 55.

¹⁶ Ruth Sullivan, *Sullivan and Driedger on the Construction of Statutes*, 4 ed (Markham: LexisNexis, 2002) at page 369.

1 While it may be appropriate for the PUB to consider relevant constitutional values in the
2 exercise of its discretion,¹⁷ reliance upon constitutional values in the determination of
3 its jurisdiction is unnecessary absent a genuine ambiguity. The interpretation of the
4 PUB's statutory grant of authority is not ambiguous when the modern principles of
5 statutory interpretation are applied. As such, resort to constitutional principles is
6 unnecessary, and could be considered improper.

7
8 Any efforts to rely upon constitutional values and *The Path to Reconciliation Act* is an
9 attempt to broaden the purpose of the PUB's rate review function to achieve a policy
10 objective not contemplated in the legislation. If permitted, this would result in an
11 unreasonable expansion of the PUB's jurisdiction beyond what was contemplated by the
12 Legislature.

13
14 While not binding upon the PUB in this matter, it is persuasive to consider parallel
15 legislation in other Canadian jurisdictions.¹⁸ Public utilities regulators in Ontario, Nova
16 Scotia, New Brunswick, Alberta and British Columbia have considered whether their
17 governing legislation grant jurisdiction to consider ability to pay in the exercise of its
18 rate setting function.

19
20 The Ontario Energy Board, pursuant to section 36(3) of the *Ontario Energy Board Act*,
21 1998, SO 1998, c. 15, has the jurisdiction to adopt any method or technique that it
22 considers appropriate in fixing just and reasonable rates.¹⁹ This provision has been
23 interpreted to allow the regulator to employ specific methods or techniques that it
24 considers appropriate to further its statutory objectives of energy conservation and the
25 protection of customer interests with respect to prices.²⁰ A majority of the Ontario
26 Superior Court of Justice held that, while cost of service and cost causality are the root
27 principles underlying the determination of rates by the Ontario Energy Board,
28 subsection 36(3) of the *Ontario Energy Board Act* permits deviation from those
29 principles and allows for the consideration of income level.²¹

¹⁷ *Doré v Barreau du Québec*, 2012 SCC 12.

¹⁸ *Canada (Canadian Human Rights Commission) v. Canada (Attorney General)*, 2011 SCC 53 at paragraphs 57 – 58.

¹⁹ *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 (Ont Sup Ct J). Found as **Appendix 14.2** to this Section.

²⁰ *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 at paragraph 55 (Ont Sup Ct J).

²¹ *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 at paragraphs 52-53 (Ont Sup Ct J).

1
2 In Manitoba, there is no equivalent provision to subsection 36(3) of the *Ontario Energy*
3 *Board Act*. The majority of the Ontario superior Court of Justice found subsection 36(3)
4 to be the primary source of the Ontario Energy Board’s jurisdiction to order low income
5 rates. In the absence of similar statutory language in Manitoba, the Ontario
6 jurisprudence is of limited assistance to the PUB. In addition, it is noteworthy that the
7 dissenting opinion of the Ontario Superior Court of Justice commented “*Were the board*
8 *to assume jurisdiction to order a rate affordability assistance program, it would be*
9 *taking on a significant new role as a regulator of social policy. Given the dramatic*
10 *change in the role that it has historically played, as well as a departure from common*
11 *law principles, it would require express language from the Legislature to confer such*
12 *jurisdiction.*”²²

13
14 The Nova Scotia Utility and Review Board does not have jurisdiction to implement a rate
15 assistance program for low income customers. The Board’s governing legislation, the
16 *Public Utilities Act*, requires all uniform rates be charged to customers in substantially
17 similar circumstances in respect of service of the same description:

18
19 67(1) All tolls, rates and charges shall always, under substantially similar
20 circumstances and conditions in respect of service of the same description, be
21 charged equally to all persons and at the same rate, and the Board may by
22 regulation declare what shall constitute substantially similar circumstances and
23 conditions.²³

24
25 The Nova Scotia Court of Appeal upheld the utility board’s finding that low income
26 residential customers receive substantially the same level of service as all other
27 residential customers and as such, subsection 67(1) of the *Public Utilities Act*, R.S.N.S.
28 1989, c. 380 prohibited differential rates based upon the customer’s income.²⁴

²² *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 2008 CanLII 23487 at paragraph 106 (Ont Sup Ct J).

²³ *Public Utilities Act*, RSNS 1989, c. 380, subsection 67(1).

²⁴ *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 at paragraph 24, leave to appeal to SCC refused 31627 (January 18, 2007) . Found as **Appendix 14.3** to this Section.

1 The Court of Appeal went on to confirm that “[t]he Board’s regulatory power is a proxy
2 for competition, not an instrument of social policy.”²⁵ Implementation of a rate
3 assistance program was found to be a public policy initiative properly within the purview
4 of the legislature, not the regulator.²⁶

5
6 Finally, the Court of Appeal considered the appellant’s argument the *Public Utilities Act*
7 ought to be interpreted in a manner that is consistent with the *Charter*. The Appellant
8 submitted that poverty is an analogous category under section 15 and as such the Court
9 could direct the institution of an ameliorative program. The Court of Appeal declined to
10 apply the *Charter* as an interpretative aid, on the grounds that there was no ambiguity
11 in the statute and the statutory language could not accommodate the construction
12 suggested by the Intervener.²⁷

13
14 In Manitoba Hydro’s respectful submission, section 67 of the Nova Scotia *Public Utilities*
15 *Act* is similar to section 39(2.1) of *The Manitoba Hydro Act*. Both provisions require
16 equal rates be charged to customers receiving substantially similar levels of service.²⁸

17
18 The New Brunswick Board of Commissioner of Public Utilities also declined to order
19 relief for low income customers, including the lowering or elimination of service
20 charges, as such programming would necessarily result in some customers paying more
21 for the same service.²⁹ The Board found that it has no legislative authority to establish
22 rates that discriminate between similarly situated customers on the basis of income.

23
24 There are a number of parallels between the New Brunswick *Electricity Act*, S.N.B. 2013,
25 c.7 and *The Crown Corporations Governance and Accountability Act*. Both statutes set
26 out a number of factors for the regulator to consider in approving rates for services

²⁵ *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 at paragraph 33.

²⁶ *Nova Scotia Power Inc., Re*, 2005 NSUARB 27 (CanLII) at paragraph 256.

²⁷ *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74 at paragraph 36-39.

²⁸ In PUB Order164/16, Order in Respect of a Review of Manitoba Hydro’s Cost of Service Study Methodology, December 20, 2016 at page 5, the PUB stated “customers are grouped into customer classes according to their similar characteristics in terms of their electricity consumption and service requirements.

²⁹ *Review of New Brunswick Power Distribution and Customer Service Corporation’s Customer Care Policies*, 29 January 2007 at pages 12-13.

1 which include “any other factors that the Board considers relevant.”³⁰ Manitoba Hydro
2 respectfully submits that the PUB can be guided by the New Brunswick jurisprudence.

3
4 The Alberta Energy and Utilities Board also held that it does not have the jurisdiction to
5 order reduced rates for certain groups of individuals based upon the social principle of a
6 customer’s ability to pay³¹, referred to as “lifeline rates”. That Board found that tariff
7 applications were an unsuitable forum to address social issues such as lifeline rates. It
8 further held that in the absence of express statutory authority, differential rates based
9 upon a customer’s ability to pay may contravene the statutory requirement that rates
10 not be unduly preferential, arbitrary or unjustly discriminatory.³²

11
12 Most recently, the British Columbia Utilities Commission found that it has the
13 jurisdiction to approve a low-income rate if there is an economic or cost of service
14 reason to do so.³³ The Commission concluded that a low-income rate in the absence of
15 an economic or cost of service justification is necessarily unduly discriminatory because
16 it differentiates between customers on the grounds of personal characteristics as
17 opposed to energy consumption.³⁴ The Commission concluded that “affordability is not
18 a regulatory justification” for the proposed low income rate.³⁵ Leave to appeal the
19 Commission’s decision was refused on the grounds that there was no reasonable
20 prospect for success.³⁶

21
22 Subsection 59(2) of the British Columbia *Utilities Commission Act*, R.S.B.C. 1996, c. 473 is
23 akin to section 39(2.1) of *The Manitoba Hydro Act*. Subsection 59(2) provides:

24
25 59(2) A public utility must not

³⁰ *Electricity Act*, S.N.B. 2013, c.7, s.103(8)(e) and *The Crown Corporations Governance and Accountability Act*, C.C.S.M. c. C336, s 25(4)(a)(ix)

³¹ Enmax Power Corporation, 2004 Distribution Tariff Application, Decision 2004-066, August 13, 2004 at page 160-161.

³² Enmax Power Corporation, 2004 Distribution Tariff Application, Decision 2004-066, August 13, 2004 at page 161.

³³ British Columbia Utilities Commission Decision and Order G-5-7, in the Matter of British Columbia Hydro and Power Authority 2015 Rate Design Application, January 20, 2017 at page 80.

³⁴ British Columbia Utilities Commission Decision and Order G-5-7, in the Matter of British Columbia Hydro and Power Authority 2015 Rate Design Application, January 20, 2017 at page 59.

³⁵ British Columbia Utilities Commission Decision and Order G-5-7, in the Matter of British Columbia Hydro and Power Authority 2015 Rate Design Application, January 20, 2017 at page 93.

³⁶ *British Columbia Old Age Pensioners’ Organization v. British Columbia Utilities Commission*, 2017 BCCA 400. Found in **Appendix 14.4** to this Section.

- 1
- 2 a) As to rate or service, subject any person or locality, or a particular description
- 3 of traffic, to an undue prejudice or disadvantage, or
- 4 b) Extend to any person a form of agreement, a rule or a facility or privilege,
- 5 unless the agreement, rule, facility, or privilege is regularly and uniformly
- 6 extended to all persons under substantially similar circumstances and
- 7 conditions for service of the same description.
- 8

9 Regulators in most other Canadian jurisdictions recognize the departure from non-

10 discriminatory rates is a significant matter, and one which ought not be undertaken

11 without express statutory authority. While recognizing that these decisions are not

12 binding on the PUB, the regulatory schemes in Nova Scotia, New Brunswick, Alberta and

13 British Columbia are sufficiently similar to that in Manitoba, and the PUB may

14 reasonably draw upon the principles set out in the above decisions.

15

16 The Appellate Court in Nova Scotia has upheld this determination, clearly articulating

17 the distinction between social policy and rate-setting. The subsidization between

18 customers on the basis of income is a policy decision that ought to be considered by the

19 Legislature. To the extent that the decision of the Ontario Energy Board departs from

20 this principal, Manitoba Hydro submits that its authority to do so is contemplated by the

21 statutory framework in Ontario, and that neither *The Crown Corporations Governance*

22 *and Accountability Act* nor *The Manitoba Hydro Act* grant the PUB similar discretion to

23 implement “any method or technique to set rates”.

24

25 **14.4 Bill Affordability Collaborative Process**

26 As directed by the PUB in Order 73/15 Manitoba Hydro led a collaborative process in

27 2016 to examine bill affordability issues. The collective effort of the participants assisted

28 in shaping the research questions and methods to be utilized to help discover and build

29 knowledge of these issues within a Manitoba context.

30

31 The Working Group members collaborated to hire a third party facilitator and research

32 firm to guide the process in the defined time period imposed by the Public Utilities

33 Board of Manitoba (“PUB”). All decisions made through the Collaborative Process were

34 done by consensus. A significant amount of work was undertaken by all actively

35 engaged working group members, with over 30 meetings (working group and

1 subcommittee) plus additional work completed outside of these meetings, until the final
2 report was filed in January 2017. The cost of the Collaborative Process was
3 approximately half a million dollars. Working group members felt the process would
4 have been further enhanced with the participation of the Assembly of Manitoba Chiefs
5 and Indigenous and Northern Affairs Canada, who were both invited but declined to
6 participate (Transcript Pages 2312 to 2314).

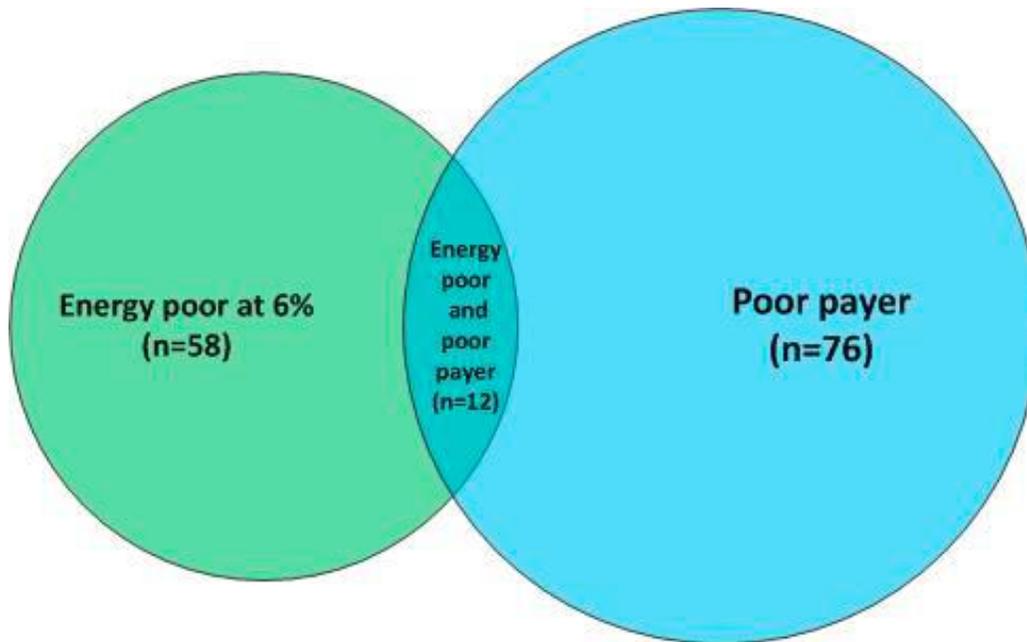
7
8 The Working Group undertook the first of its kind study of energy poverty in Manitoba
9 with the assistance of Prairie Research Associates. The research work followed a
10 defined research framework which the working group agreed to and included a
11 literature review, definition of energy poverty, key interviews, a consumer telephone
12 survey of Manitoba Hydro customers, analysis of Manitoba Hydro administrative data
13 linked with survey responses, quantitative modelling of rate options and projections of
14 potential rate increases with the associated impact to customer's energy burdens (Bill
15 Affordability Working Group Report , Appendix 10.5 of the Application, page 45 of 242).

16
17 Some of the key findings were a surprise to the Working Group based on preconceived
18 assumptions as few customers are poor payers and energy poor, energy poverty is not a
19 prime cause of arrears and there was little correlation between electricity consumption
20 and income (Manitoba Hydro Cost of Service, Rate Design and Bill Affordability Panel
21 Presentation, Exhibit MH-88).

22
23 The consumer research revealed the link between arrears and energy poverty is
24 relatively weak. The research showed that between 14% of customers who experienced
25 arrears would be classified as energy poor using a 6% of income threshold, while just
26 under 10% of the overall customer base would be classified as energy poor using the
27 same threshold (Appendix 10.5 of the Application, page 18 or 242). While this
28 demonstrates customers who are classified as energy poor are somewhat more likely to
29 experience arrears, the vast majority of customers experiencing arrears cannot be
30 considered energy poor.

1

Figure 14.1 Energy Poor and Poor Payer Households – General Sample



2

3

Source: Figure 3, PRA – Bill Affordability Research Services Final Report – January 9, 2017 (Appendix 10.5 of the Application, page 77 of 242)

4

5

6

This finding had significant implications for the research and the understanding of the issue. It also has significant implications for Manitoba Hydro in terms of how it can address these issues from a business perspective. The research showed that 86% of customers who experience arrears are not considered energy poor using a 6% energy burden threshold (Appendix 10.5 of the Application, page 77 of 242). This means that even a program that perfectly targeted customers classified as energy poor would be poorly targeted when the benchmark is Utility revenues and costs. On the other hand, an arrears forgiveness program would need to be extremely well targeted to benefit customers who are considered energy poor while not providing benefits to customers who fall outside that definition.

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The working group also reviewed Manitoba Hydro's existing programs and initiatives which assist those struggling with energy bills. Ultimately, the working group did not include a recommendation to implement a subsidized rate design as the cost to Manitoba Hydro and therefore ratepayers was too significant to offset any reduction in Manitoba Hydro's collection costs.

1 Of the recommendations made by the working group, many were for Manitoba Hydro
2 to continue its offerings and where practical, seek to further enhance them.

3
4 New program offerings are being implemented or piloted at Manitoba Hydro as a result
5 of this collaborative work such as Energy Instalment Affordability Program and an
6 arrears management initiative (Transcript Page 2289 and 2507 to 2508). Manitoba
7 Hydro has also enhanced its Affordable Energy Program to increase the number of LED
8 bulbs provided to 10 (Transcript Page 2489).

9
10 Manitoba Hydro has continued to work to address issues of energy poverty stemming
11 from the collaborative process by undertaking an additional survey of Indigenous
12 consumers with respect to Bill Affordability to gain further insight (AMC/MH I-4).
13 Manitoba Hydro also convened its Bill Affordability Advisory Committee (formerly
14 known as the Affordable Energy Advisory Committee) and invited all of the working
15 group members on June 22, 2017. The meeting provided an update of Manitoba Hydro's
16 efforts since January 2017 and sought feedback from those three members who
17 attended (Transcript Page 2505). Moving forward, Manitoba Hydro believes all parties
18 need to be fully engaged and participate in further exploring issues of energy poverty.

19
20 Manitoba Hydro is of the view that this stakeholder engagement was a valuable step
21 forward in building understanding on the issue. Given that the outcomes of some of the
22 research were contrary to assumptions held by many parties at the outset, the report of
23 the Working Group forms a base of understanding for addressing these issues going
24 forward.

25 26 **14.5 Manitoba Hydro's Affordability Programs**

27 Manitoba Hydro maintains a suite of initiatives aimed at enhancing the affordability of
28 its service for customers with high energy usage, low incomes, or a combination of the
29 two.

30 31 **14.5.1 Bill Management Activities**

32 As discussed in Appendix 10.8 of the Application, Slides 23 and 25 of Exhibit MH-88, and
33 by Mr. Paul Chard at Transcript Pages 2286 to 2287, Manitoba Hydro undertakes a
34 number of activities to assist customers in managing their electric and natural gas bills.
35 Many of these activities have evolved over time to respond to changing conditions or

1 requirements. One of the longest standing and most popular programs in this area is the
2 Equal Payment Plan which helps customers smooth their payments throughout the
3 course of the year despite periods of high consumption (in winter months) and low
4 consumption (in summer months) within the year. More than one-quarter of Manitoba
5 Hydro's electric customers use this program. As discussed in the Transcript Page 2287,
6 customers who require additional assistance in budgeting or managing their bill
7 payments, are offered customized due dates and flexible payment arrangements from
8 Manitoba Hydro. Payment arrangements allow for payment of bills in a series of smaller
9 installments over time. When such payments plans are required for reasons of
10 insufficient income, late payment charges are waived to ensure the customers financial
11 concerns are not compounded. Manitoba Hydro also works with Income Assistance
12 administrators in First Nation communities and with the provincial Employment and
13 Income Assistance program to ensure that appropriate social assistance payments are
14 applied to accounts. As noted by Mr. Chard on Transcript Page 2287, an enhancement
15 to the Equal Payment Plan will be introduced in 2018 entitled the Energy Affordability
16 Instalment Plan. This program came about as a result of the recommendations of the bill
17 affordability collaborative process. The program will take a customer's arrears balance
18 and spread it out over a longer period. Those repayment amounts will then be
19 integrated with an equal payment plan amount into a single payment for the customer
20 to manage.

21 22 **14.5.2 Neighbours Helping Neighbours**

23 As discussed during the course of the hearing and outlined at Transcript Page 2293,
24 Manitoba Hydro offers the Neighbours Helping Neighbours program which provides a
25 one-time financial grant to those facing a financial crisis. The program is offered in
26 partnership with the Salvation Army, who administers the program, and since 2004,
27 there have been approximately 8,000 financial grants offered to customers requiring
28 assistance for a total of \$2,665,337 (Slide 27 of Exhibit MH-88). In addition, the Salvation
29 Army provides additional support services such as counselling, budget skills, job training
30 and food assistance according to the unique needs of each customer and Manitoba
31 Hydro provides access to a specialist in its credit recovery services department who
32 works with customers and connects them with additional community support where
33 they can obtain additional assistance.

34

1 As noted further in its oral direct testimony at Transcript Pages 2293 to 2294, Manitoba
2 Hydro covers all of the Salvation Army's administration expenses along with matching
3 customer donations dollar for dollar. In terms of the donations to the program, as can
4 be seen on slide 27 of Exhibit MH-88, customers have donated \$465,360. Not only has
5 Manitoba Hydro matched donations dollar for dollar, Manitoba Hydro has also provided
6 funds for the shortfall of donations that is required to meet the needs of the program.
7 Manitoba Hydro's funding has been approximately \$2.2 million, which translates to
8 approximately 88% of all expenses for the Neighbours Helping Neighbours program
9 being covered by Manitoba Hydro. With respect to the administrative expenses,
10 Manitoba Hydro has covered over \$1 million dollars related to the administrative
11 expenses of the Salvation Army, which does not include administrative expenses related
12 to Manitoba Hydro's efforts related to the program.
13

14 **14.5.3 Affordable Energy Program ("AEP")**

15 As explained in Manitoba Hydro's Annual Affordable Energy Program Report at
16 Appendix 10.8 of the Application, page 2, Manitoba Hydro's Affordable Energy Program
17 assists lower income customers with energy efficiency upgrades through a turnkey
18 approach where customers receive a free in-home energy review, free basic energy
19 saving measures, free insulation including installation and the provision for a low cost
20 high efficient natural gas furnace when converting from a standard efficient natural gas
21 furnace for only \$9.50/month over five years interest free. As discussed in Transcript
22 Pages 2489 to 2490 and 2511 to 2515, Manitoba Hydro has implemented improvements
23 to its AEP, including increasing the offering of four LED bulbs to ten LED bulbs, and
24 accepting alternative forms of income tax verification. An online application was also
25 created in July 2015 to provide a more efficient option for an application system, and
26 approximately 40% of AEP applications are now received through the online application
27 form (as noted in response to PUB-MH-I-126 b-e).
28

29 Manitoba Hydro also continues to address barriers to participation in the AEP. As
30 discussed in PUB/MH I-126 b-e, customers do not tend to experience a sense of urgency
31 to acquire a new furnace or insulation except in the case of malfunction. Manitoba
32 Hydro addresses this by forming strategic relationships with community groups (e.g.
33 North End Community Renewal Corporation, Brandon Neighbourhood Renewal
34 Corporation, Selkirk Community Renewal Corporation, Dakota Ojibway Tribal Council,
35 and Manitoba Metis Federation) whereby Energy Advocates from these organizations

1 attend community events and canvass neighborhoods to directly explain the benefits
2 and bill savings associated with the eligible energy efficiency upgrades. Continuous mass
3 media and targeted marketing throughout the year along with internal promotion by
4 Manitoba Hydro staff (Contact Center and Credit & Recovery Services departments) is
5 also utilized to ensure that the AEP is top of mind whenever customers are looking to
6 lower their energy bills, or upgrade their furnace and insulation. Targeted marketing
7 efforts include autodialed calls to customers in arrears and direct mail letters and
8 brochures to areas in Winnipeg and rural towns with higher incidences of low income
9 populations. Promotional materials such as brochures, magnets and bookmarks are also
10 distributed to local community centers and libraries across the province.

11
12 As further noted in response to PUB/MH I-126 b-e), Manitoba Hydro also specifically
13 targets customers with higher than average energy consumption offering a free Home
14 Energy Assessment (same offer as the in-home review provided under AEP) via mail and
15 direct call campaigns. Customers are subsequently encouraged to apply to the AEP or
16 any other Power Smart programs. Dedicated customer service portals such as a direct
17 phone line, toll free phone number and email inbox also provide customers easy access
18 to knowledgeable staff in order to complete the required eligibility and subsequent
19 upgrade forms required to participate in the program. A video that will explain the steps
20 of participation in the AEP is also currently in development. The first part of the video
21 which gives an overview of the AEP is currently available on the Manitoba Hydro
22 website (Transcript Page 2301). As discussed in Manitoba Hydro's Written Rebuttal
23 Evidence, Exhibit MH-52, these continued efforts have attributed to the success of
24 Manitoba Hydro providing over 20,000 lower income customers with energy efficient
25 upgrades.

26
27 There have been some criticisms levied at Manitoba Hydro's Affordable Energy Program
28 based on cursory reviews of the AEP. Dr. Simpson provides general comments regarding
29 the AEP being a modest starting point, that significant barriers to participation exist,
30 that better coordination is required between the AEP and other bill assistance
31 programs. These comments understate the achievements of the program to date. While
32 programs expand and evolve and there are always opportunities to improve programs,
33 Manitoba Hydro aggressively markets its Affordable Energy Program to educate
34 customers on the benefits of the program with mass media efforts as noted above, a
35 video tailored to the target market and through customized outreach within the

1 community as discussed in Manitoba Hydro’s Annual Affordable Energy Program Report
2 at Appendix 10.8 of the Application, page 5 of 21.

3
4 The Bill Affordability Working Group identified key strengths of the Affordable Energy
5 Program including, participation and savings with retrofits made to almost 18,000
6 homes, accessibility by addressing the unique barriers low income customer face by
7 minimizing the financial burdens associated with upgrades; addressing eligibility by
8 targeting gas and electric savings measures to low-income customers; a reflection of
9 savings demonstrating estimated annual bill reductions per customer from anywhere
10 between \$37 (as a result of basic measures) and \$556 (for insulation in electric heated
11 homes); and outreach to customers by delivering and expanding awareness of the value
12 and benefits of the AEP program (Appendix 10.5 of the Application, page 23). In
13 addition, the conclusions of the Bill Affordability Working Group Report, at page 22,
14 “Throughout the collaborative process, the AEP was shown to be well-managed and
15 achieving solid results to date.” and at page 24, *“Recent evaluations and studies
16 conducted by other researchers generally reflect positively on the design of the AEP and
17 the results it has achieved to date.”* As further noted in the findings of an independent,
18 external review of the Affordable Energy Program by Dunsky Energy Consulting ,
19 provided as an attachment to AMC/MH I-37, page 67, “Results in terms of participation
20 rates, install rates and savings are strong”.

21
22 With respect to the coordination of the AEP with other bill assistance programs,
23 according to an independent review of The Affordable Energy Program by Dunsky
24 Energy Consulting which also included a review of Customer Billing Assistance Initiatives
25 , provided as an attachment to AMC/MH I-37, page 54, *“There is significant coordination
26 between the Affordable Energy Program and Bill Assistance program...”* . Since the
27 Dunsky review, as noted in Ms. Galbraith’s direct testimony at Transcript Page 2296,
28 Manitoba Hydro has further enhanced the coordination between programs. In March
29 2017, to ensure increased participation, a mandatory joint application form for both the
30 Affordable Energy Program and Neighbours Helping Neighbours was created. In
31 addition, at Transcript Page 2298, Ms. Galbraith discussed the new approach to landlord
32 and tenant situations and how Manitoba Hydro is continually following up with
33 landlords on behalf of their tenants to encourage the landlords to participate in the
34 Affordable Energy Program for their revenue properties. As noted by Ms. Galbraith,
35 Manitoba Hydro has noticed an increased number of customers participating in both the

1 Neighbors Helping Neighbors and the Affordable Energy Program; an increase from 14%
2 to 28%.

3
4 Manitoba Hydro continually looks to increase participation for lower income customers
5 who are struggling with payment of their energy bill such as increased awareness
6 through various media, bill inserts, canvassing, energy advocates, community groups
7 and centres, tradeshow, targeted calling of customers in arrears by the Affordable
8 Energy Program and frontline staff in the Contact Centre and Credit department
9 promoting the AEP.

10 11 **14.5.4 Indigenous Power Smart Program**

12 As shown in slides 34 to 36 of Exhibit MH-88 and as further discussed on Transcript
13 Pages 2301 to 2306, Manitoba Hydro is taking a comprehensive approach with respect
14 to Indigenous Demand Side Management. Manitoba Hydro's Indigenous Power Smart
15 Program is customized to meet the unique needs of Indigenous communities. As
16 indicated in PUB-MH-I-126 b-e, all homes located on First Nations reserves are eligible
17 to participate regardless of income level. A dedicated Indigenous Energy Advisor works
18 with each Indigenous community's Band Housing Manager (Transcript Pages 2301 to
19 2302) or housing designate (Transcript Page 3339) to identify qualifying homes and
20 recommends energy efficient measures. While there has been some question with
21 respect to Manitoba Hydro's use of one dedicated Indigenous Energy Advisor
22 responsible for serving all 63 First Nations (Page 27 of Exhibit AMC-7-1), it is through this
23 one point person that has led to the success of the program. The Indigenous Energy
24 Advisor works directly with band housing managers to confirm with his feet on the
25 ground as to what homes would still be eligible for installation upgrades (Transcript
26 Page 2656) Ms. Galbraith explained at Transcript Page 2301 that this band housing
27 manager has the intimate knowledge of the housing stock in communities and is the
28 liaison with any federal government housing programs.

29
30 As noted at Transcript Page 2302, as part of the Indigenous Power Smart Program,
31 Manitoba Hydro also provides the training and funding for the local residents to
32 complete the installations of both the insulation and basic measures which create
33 employment for members of the community. There is no cost to the indigenous
34 community to participate. With over 5,000 homes having received retrofits through the

1 program, the equivalent of 22 full time jobs of Indigenous employment has been
2 generated (PUB-MH I-126 b-e).

3
4 As further noted in PUB-MH-I-126 b-e, energy saving seminars are also available to
5 provide community members with information and tips on what they can do to make
6 their communities more energy efficient. In addition, a customized Heat Recovery
7 Ventilation (“HRV”) video explaining how to operate and maintain the unit was created
8 to assist the Band Housing Managers. The video is currently available in three languages:
9 English, Ojibway and Cree, and Dene (Transcript Page 2300). As further described in
10 response to PUB/MH I-126 b-e, the video was distributed to all applicable First Nation
11 Band Housing Managers and is also posted on the Manitoba Hydro’s website. In
12 addition, a customized Indigenous Energy Savings Tips publication was also created for
13 use at events and it is distributed to each home as they participate through the direct
14 install channel.

15
16 Upon reviewing the data provided by Manitoba Hydro in response to AMC/MH II-5 a-g
17 that almost one-third of all First Nation on-reserve dwellings have participated in
18 Indigenous Power Smart and 18.7% have received insulation retrofits, Mr. Raphals
19 commented as follows, *“While there is clearly a long way to go, these results testify to a*
20 *serious effort on the part of Manitoba Hydro to reach First Nations communities”*. (Page
21 27 of Exhibit AMC-7-1).

22
23 As noted at slide 35 of Exhibit MH-88, the total estimated Indigenous insulation target
24 market is 3,778 homes. Manitoba Hydro has made significant achievements in terms of
25 insulation efforts under the Indigenous Power Smart Program where 3,254 homes have
26 received insulation upgrades as of October 31, 2017 which represents 86% of the
27 estimated insulation market (Transcript Page 2303). In addition to these insulation
28 upgrades, in approximately three years, over 5,000 homes have received basic measures
29 which represents approximately one third of the overall Indigenous market (Transcript
30 Page 2305). As shown in Exhibit MH-52, since its inception, the Indigenous Power Smart
31 Program has achieved 1% to 16% participation annually. In its review of the Affordable
32 Energy Program Report at page 21, Dunsky Energy Consulting noted that in his review of
33 leading programs, the best programs achieve participation rates of 1% to 4% annually
34 (AMC/MH I-37- Attachment 1).

1 In terms of the Manitoba Keewatinowi Okimakanak (“MKO”) communities, as shown on
2 slide 37 of Exhibit MH-88 and discussed at Transcript Pages 2305 to 2306, as of October
3 31, 2017 1,320 homes of an estimated 1,468 in the MKO communities have received
4 insulation upgrades through the Indigenous Power Smart Program. This represents a
5 90% completion rate. Additionally, 1,790 homes of the estimated 7,375 have received
6 the basic measures, representing approximately 24% of the market.

7 8 **14.6 Demand Side Management Programming and Efficiency Manitoba**

9 While the preceding section discussed programs that are specifically targeted at lower
10 income customers, Demand Side Management programs have been and continue to be
11 a key strategy for assisting all customers in managing their energy use, making energy
12 more affordable. Manitoba Hydro currently offers a wide and comprehensive suite of
13 programs as outlined in the 2017/18 Demand Side Management Plan (PUB MFR 61 -
14 Attachment 1).

15
16 At Tab 7 of the Application, Manitoba Hydro has highlighted the DSM initiatives that
17 have been implemented in the last couple of years since the last GRA. These include
18 new DSM initiatives and enhancements to existing initiatives that have been introduced
19 to assist all customers in managing energy bills. As shown on slide 38 of Exhibit MH-88,
20 Manitoba Hydro has a variety of programs continuing to support all customer classes.
21 New programs which have been introduced in the last couple of years include the Solar
22 Energy Program, Power Smart Shops Program, Condensing Commercial Water Heater
23 Program, Commercial HRV Program, Parking Lot Controller Program, New Homes
24 Program, Residential Instant Rebates & Bill Credits Program, and Residential HRV
25 Controls Program. In addition, a number of enhancements to existing Power Smart
26 programs were introduced, such as increased incentives, new measures, and enhanced
27 sales and technical support which are further outlined in Tab 7 of the Application.

28
29 In addition to the significant efforts achieved through the Indigenous Power Smart
30 Program, First Nation Communities, benefit from other customized DSM initiatives. At
31 Transcript Page 2310, Ms. Lois Morrison highlighted the Community Geothermal
32 Program. Under the program, Manitoba Hydro worked with Aki Energy, a non-profit
33 indigenous social enterprise funded by Manitoba Hydro, in order to install geothermal
34 heat pump systems in residential homes. As of July 2017, Manitoba Hydro has had
35 upgrades installed in 340 homes since the program began in April 2013. In addition to

1 this, Ms. Morrison discussed at Transcript Page 2311 that Manitoba Hydro provides
2 technical guidance and financing through its PAYS Program to cover the up-front cost of
3 the installations. For homes where the energy savings do not offset the financing costs
4 of the geothermal systems, Manitoba Hydro will provide additional financial support. As
5 further noted, the community invests in training local members to install the systems
6 with 45 band members to date being trained and nine accredited as installers.

7
8 Ms. Morrison also highlighted the community energy profiles as another Manitoba
9 Hydro offering. At the community's request, Manitoba Hydro will provide a report
10 outlining the historical energy use trends by residential customers in their communities,
11 and for the individual band-owned buildings in the community. (Transcript Page 2311)
12 As noted by Ms. Morrison, we continue to be in discussions with communities and
13 pursue these opportunities as they arise.

14
15 The 2016/17 DSM Plan – 15 Year Supplemental Report (Appendix 7.2 of the Application)
16 projects average annual DSM savings of 1.2% of load which, although lower than the
17 1.5% targets identified in the Efficiency Manitoba Act. Mr. Bowman argues that
18 Manitoba Hydro's forecasts for DSM spending are substantial and well beyond what can
19 be justified on economic and cost effectiveness grounds. Mr. Bowman suggests that
20 Manitoba Hydro should assume a substantially lower DSM investment and projected
21 energy savings in its Application and determination of future revenue requirements
22 when he states that *"it is appropriate to consider the likelihood that Efficiency Manitoba,*
23 *its Minister, or the PUB will make a finding that continuing large-scale DSM is not cost*
24 *effective for at least the next 5 – 7 or so years. Hydro should take this likelihood into*
25 *account in its planning and budgeting"* (Patrick Bowman Pre-Filed Testimony, filed on
26 behalf of the Manitoba Industrial Power Users Group, MIPUG-13, Page 6-25).

27
28 The Efficiency Manitoba Act received royal assent in June, 2017 and was proclaimed on
29 January 24, 2017. There has been no evidence to suggest that the new entity or its
30 planned activities will differ from those established in The Efficiency Manitoba Act or
31 the 2016/17 DSM Plan. The Efficiency Manitoba Act requires a cumulative 22.5% energy
32 savings over 15 years; it does not mandate specific year over year savings. To arbitrarily
33 reduce forecasted DSM in the face of a legislative mandate that exceeds Manitoba
34 Hydro's current plan, which outlines 17.3% energy savings over 15 years, is poor
35 planning practice and there is absolutely no basis for considering such a suggestion.

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In terms of next steps, as Ms. Morrison discussed at Transcript Page 646, , the responsibility for the planning, design and implementation of Demand Side Management programs will transition to the new Crown Corporation, Efficiency Manitoba. As Ms. Morrison testified:

"Now, the challenge that we are facing is, as I mentioned during my testimony at the revenue requirement panel, we're in a holding pattern on pursuing new opportunities or expanding our DSM offerings until we pass the torch effectively over to Man -- Efficiency Manitoba" (Transcript page 2608).

In addition, The Efficiency Manitoba Act outlines a continuing key role for the PUB in the review of Demand Side Management activities in Manitoba as outlined under section 8.2.7.

1 **15 COST OF SERVICE AND RATE DESIGN**

2 **15.1 Rate Setting Process**

3 Manitoba Hydro provided the PUB panel with an overview of the rate setting process in
4 its direct evidence presentation on December 19, 2017. As discussed on Transcript
5 Pages 2258 to 2261, there are three sequential steps to the setting of electricity rates.

6
7 In the first step, the overall level of the revenue requirement is determined. After the
8 total amount of the revenue requirement is finalized and confirmed, the Cost of Service
9 Study is used to apportion the total revenue requirement to each customer class. The
10 Cost of Service Study evaluates the allocated revenue requirement against the revenues
11 expected to be generated by rates, and determines the Revenue to Cost Coverage
12 (“RCC”) ratio for each customer class.

13
14 Should the PUB determine that an adjustment to class revenues is needed to address
15 any specific class RCC’s that may lie outside of a zone of reasonableness, that decision
16 must be explicit and determined prior to designing rates. Class revenues should be
17 confirmed and then rates can be designed to recover the finalized level of revenues for
18 each customer class, on a forecast (weather normal) basis.

19
20 In its direct evidence presentation, Manitoba Hydro noted its primary rate design
21 objective, and how it related to one of Bonbright’s “*Criteria of a Sound Rate Structure*”.
22 Manitoba Hydro views its primary rate making objective as stated on page 2 of Tab 9 of
23 this Application:

24
25 *“Recovery of Revenue Requirement – Rates must provide the Corporation the*
26 *opportunity to fully recover its allowed revenue requirement.”*

27
28 Similarly, Professor James Bonbright states that a sound rate structure should have:

29
30 *“Effectiveness in yielding total revenue requirement under the fair-return standard*
31 *without any socially undesirable expansion of the rate base or socially undesirable level*
32 *of product quality and safety”* (Page 30 of Manitoba Hydro’s Book of Documents No. 2,
33 Exhibit MH-116-2).

1 Both of these objectives reinforce the desirability of rates being designed to recover, to
2 the fullest extent possible, the amount of revenue requirement identified as being the
3 responsibility of each individual customer class.
4

5 Therefore, in the event that the PUB determines that revenues must be shifted between
6 classes to achieve a change in RCC, that direction should be made prior to the
7 calculation of rates for final approval. In that way, Manitoba Hydro will be able to
8 design rates to accomplish the desired shift of RCC's while maintaining overall the ability
9 to fully recover its allowed revenue requirement.
10

11 **15.2 COST OF SERVICE**

12 **15.2.1 Intervenors Have Endorsed the PCOSS18 Implementation of the Directives** 13 **from Order 164/16**

14 Manitoba Hydro has provided a cost of service study in this Application that it views as
15 essentially fully compliant with the methodology directed in Order 164/16. Intervenors
16 who offered comments on the cost of service methodology appeared to share the view
17 that changes made for Prospective Cost of Service Study 18 ("PCOSS18") were
18 consistent with the Public Utilities Board of Manitoba ("PUB") direction in Order 164/16,
19 and further that any outstanding matters were relatively minor.
20

21 Mr. Bowman provided his endorsement of the Corporation's implementation of the
22 directives:
23

24 *"Reviewing the filing, my conclusion was of the cost of service study as filed largely*
25 *follows Order 164/16. It's refreshing to have a cost of service study that aligns with and*
26 *an order and that needs at most some – some small outstanding directives dealt with"*
27 (Transcript Page 6101).
28

29 Mr. Harper echoed this view during his direct presentation:
30

31 *"So if we're on slide 26, in terms of Manitoba Hydro's implementation of Order 164/16,*
32 *their pers -- perspective cost of service study for 2018 generally follows the methodology*
33 *set out in the Board's Order. There are a few areas of departure. However, in my view,*
34 *these are based on either a lack of data, or simplifying assumptions"* (Transcript Page
35 5229).

1
2 Finally, Mr. Chernick offered, on page 44 of his Direct Testimony, on behalf of the Green
3 Action Centre, Exhibit GAC-11, that he had

4
5 *“not identified any problems with the Company’s revisions to its cost- of-service study*
6 *methodology to reflect the Board’s Order 164-16”.*

7
8 Manitoba Hydro acknowledges there are two outstanding directives in PUB Order 164-
9 16 that remain to be addressed in the next cost of service study, specifically Directive
10 1(v) to update the weighted allocator for service drops, and Directive 1(gg) to study the
11 allocation of common costs. Manitoba Hydro does not expect that the final outcome of
12 these two remaining directives would materially impact the RCC outcomes of the next
13 cost of service study, as discussed below.

14
15 The annual revenue requirement associated with Service Drops represents only one
16 tenth of one percent of the total revenue requirement (Schedule 4.1 of Appendix 8.1 of
17 this Application). Even with some unforeseen dramatic change in the class weighting
18 factors or allocation method, the minimal dollars at stake simply cannot result in any
19 significant changes to the level of allocated costs by class.

20
21 With regard to the treatment of common costs, while the quantum of common costs is
22 greater, Manitoba Hydro does not anticipate any significant changes in the methodology
23 used to functionalize these costs or in their ultimate allocation to customer classes.
24 During the Hearing Mr. Barnlund shared the corporation’s view that the current
25 approach is reasonable and that parties should temper any expectations that there may
26 still be large impacts to come from the upcoming review of common costs.

27
28 *“And so while the Board had encouraged us to look to see if there's other methods*
29 *which conceivably could be more cost causal, our current view is that the interim*
30 *approach that we are us -- that we are using, and I would say this is the approach*
31 *that we've been using for twenty (20) years. So, you know, it's not like this is*
32 *something that we have -- have not used in the past. We have used this all the time.*

1 And -- and it's a reasonable way of allocating common costs. Your activities relate to
2 a function, right. And so you can use that as being the driver to be able to drive
3 common costs, and that's what we currently do.

4
5 Now, which isn't to say that we're not going to take a look at this from that
6 perspective because the Board has asked us to look at it and we will do that. But, you
7 know, I -- I don't want to leave this discussion with the impression that the way of
8 allocating common costs is -- is lacking something. No, it's a valid allocator and it's
9 an allocator that's been in use for over twenty (20) years here with Manitoba Hydro"
10 (Transcript Page 2574).

11
12 Manitoba Hydro also notes that the examination of the treatment of common costs in
13 the Cost of Service Methodology Review did not generate controversy. The PUB itself
14 noted in Order 164/16 at the bottom of page 90, that:

15
16 *"The issue of the allocation of common costs was not contentious in this proceeding and*
17 *the interveners did not put positions forward."*

18
19 **15.2.2 Eliminating Non Cost Casual Factors from PCOSS Requires a Revision to the**
20 **Zone of Reasonableness**

21 In Order 164/16, the PUB provided clear direction on the methodology to be used in
22 the preparation of future cost of service studies, as well as its view that cost causation
23 should be the primary objective of a cost of service study and that other ratemaking
24 principles should be considered at the rate setting stage after the cost of service results
25 are known³⁷. Manitoba Hydro has proposed in this Application that the PUB could
26 consider expanding the zone of reasonableness from the current 95% to 105% band to a
27 broader 90% to 110% range in response to this updated view on the role of cost of
28 service in rate making.

29

³⁷ Order 164/16, page 27 – Board Findings “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. While ratemaking principles are important in the overall process of setting rates, these concepts are issues for rate design and should therefore not be considered at the COSS stage. Likewise, consideration of RCC ratios is a rate design matter that should be addressed in the rate-setting phase of the GRA.”

1 A broadening of the Zone of Reasonableness (“ZOR”) is justified to accommodate the
2 pre-existing fairness and equity matters that were considered at the time of the 2016
3 Cost of Service Methodology Review. For example, the elimination of the uniform rates
4 adjustment from the study has reduced the revenues attributed to the Residential class
5 by \$21 million dollars (Coalition/MH II -85) in the 2018 study. If the use of the Uniform
6 Rate Adjustment had been maintained, the RCC of the Residential class would have
7 been approximately 1.6% higher at 96.4%, which would fall within the current ZOR
8 (Transcript Page 3017).

9
10 The use of a widened zone of reasonableness also appears to be supported by practice
11 in other Canadian jurisdictions. An informal survey conducted by Mr. Harper indicated
12 that most two common ranges used in Canada are 95-105 and 90-110, and that even
13 wider ranges are applied on a class by class basis by the OEB (Page 29 of William Harper,
14 Econalysis Consulting Services Evidence filed on behalf of the Consumer’s Coalition,
15 Exhibit CC-20).

16 17 **15.2.3 Revising the Method of Calculating RCC Would Require an Expansion to the** 18 **Zone of Reasonableness**

19 Manitoba Hydro traditionally calculates the RCC ratio by adding class revenues to the
20 classes’ share of Net Export Revenues, and then dividing those combined revenues by
21 the allocated cost for the class. The existing RCC methodology has been utilized by
22 Manitoba Hydro in each of its cost of service studies since 1979 (GSS-GSM/MH I-9). The
23 calculation was used in this form when the ZOR was initially established; as we well as in
24 1996 when the zone was reviewed and reduced to the current 95-105% range as noted
25 in PUB Order 51/96.

26
27 Mr. Bowman proposes modifying the long standing calculation to use export revenues
28 as a reduction to cost in the denominator of the ratio, rather than as part of the
29 calculation of total revenue in the numerator. He suggests this approach would provide
30 results that are more relevant to customers (Transcript Page 6102), although he
31 provides no evidence as to why a customer would prefer one methodology over
32 another.

33
34 Manitoba Hydro has acknowledged this alternative approach is simply a re-ordering of
35 the algebra in the equation, however, Manitoba Hydro cautions that this alternative

1 approach generates results with a much broader set of RCC outcomes (93.5 to 115.7) for
2 PCOSS18 when compared to the current method (94.8 to 112.5) as shown in response
3 to GSS-GSM/MH I-9. As further noted by Manitoba Hydro, the difference between the
4 two methods will decrease as the revenue cost coverage ratios approach unity.

5
6 For classes outside the ZOR the differences can be significant. Using the traditional
7 formula indicates that the GSL >100kV class is 3.6% above the 105% upper bound of the
8 zone of reasonableness. Under the modified calculation proposed by Mr. Bowman, the
9 variation from the upper bound doubles to 7.3% This alternate representation of the
10 very same set of costs and revenues suggests a much more dramatic and immediate
11 rate adjustment may be required than using the metrics as normally employed.

12
13 Changing the calculation of RCC should not be done in isolation, and must be
14 accompanied with a reexamination of the appropriate ZOR.

15
16 Switching to the modified calculation of the RCC ratio should not be considered as this
17 approach would represent a significant departure from the traditional RCC calculation
18 that has been used to report PCOSS outcomes since the adoption of a ZOR. If the RCC
19 formula is changed, it will not produce results that are directly comparable to those
20 historically reported. Furthermore, a change in the RCC formula should then be
21 accompanied by adopting a wider zone of reasonableness.

22 23 **15.2.4 Outcomes of PCOSS18**

24 Based on Manitoba Hydro's proposed expansion of the zone of reasonableness to 90%
25 to 110%, all but one class would be captured within the revised zone of reasonableness.

1

Figure 15.1 PCOSS18 Results Compared to Zone of Reasonableness

Customer Class	PCOSS18 RCC³⁸	Compared to 95-105% ZOR	Compared to 90-110% ZOR
Residential	94.8%	-0.2%	In ZOR
GSS Non Demand	112.5%	+7.5%	+2.5%
GSS Demand	101.0%	IN ZOR	IN ZOR
GSM	98.3%	IN ZOR	IN ZOR
GSL 0-30 kV	99.1%	IN ZOR	IN ZOR
GSL 30-100 kV	109.3%	+4.3%	IN ZOR
GSL >100 kV	108.6%	+3.6%	IN ZOR
Area & Roadway Lighting	100.3%	In ZOR	IN ZOR

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While Manitoba Hydro is not proposing to shift revenues between customer classes to adjust RCC's, it recognizes that the PUB may determine to do so. If downward adjustment is made to one customer class, it should be recognized that the adjustment will require an upward adjustment to the other customer classes in order to maintain revenue neutrality and to afford Manitoba Hydro the opportunity to recover its full revenue requirement.

10

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16

In the event that the PUB direct revenue changes by customer class, Manitoba Hydro requests that this matter be addressed explicitly and transparently in its rate Order for this GRA. Manitoba Hydro would request that the PUB provide clear direction as to how much revenue is to be shifted away from any given customer class and provide direction as to which customer classes would be responsible for those revenues, so as to keep Manitoba Hydro whole for its total approved revenue requirement.

17

15.2.5 RCC Evaluation Should Not Ignore Impact of Bipole III Coming in Service

18

19

20

BPIII is currently under construction and not yet in-service, and is therefore not reflected in the revenue requirement used for PCOSS18. However, the project will be part of the next cost of service study to be reviewed by this Board and it is appropriate

³⁸ Appendix 8.1, Schedule 1.1

1 to consider the results of PCOSS18 in conjunction with the directional changes expected
2 in the next study.

3
4 The additional revenue requirement related to this massive Generation-functionalized
5 asset will result in significant and predictable changes to class cost responsibility in
6 future cost of service studies. In this application Manitoba Hydro has provided an
7 alternate version of the cost of service study that includes an estimate of the revenue
8 requirement for 2019/20 to illustrate the changes that are expected due to the addition
9 of Bipole III.

10
11 The RCC for the smaller distribution level customers are expected to increase by up to
12 two or three percentage points, with a more dramatic six or seven percent decrease
13 expected to the RCC of the industrial classes.

14
15 **Figure 15.2**

Customer Class	PCOSS18 RCC³⁹	Estimated 2020 RCC with BPIII In Service⁴⁰	Estimated RCC Change
Residential	94.8%	96.7%	1.90%
GSS Non Demand	112.5%	115.3%	2.80%
GSS Demand	101.0%	101.3%	0.30%
GSM	98.3%	97.4%	-0.90%
GSL 0-30 kV	99.1%	96.5%	-2.60%
GSL 30-100 kV	109.3%	103.5%	-5.80%
GSL >100 kV	108.6%	101.5%	-7.10%
Area & Roadway Lighting	100.3%	118.2%	17.90%

16
17 These impacts by class are predictable based on each class' relative usage of the bulk
18 power system, as well as the change in cost structure due to the significant, lumpy

³⁹ Appendix 8.1, Schedule 1.1

⁴⁰ MIPUG/MH I 23a-b

1 increase in the amount of Generation-related revenue requirement included in the
2 study. The expected change in costs is sufficient to move the RCCs for both the
3 Residential and Industrial customers to within the zone of reasonableness as soon as
4 Bipole III comes into service without the need for any additional rate differentiation.

5
6 These results have been generally accepted by Mr. Bowman:

7
8 *"I think Bipole III will likely have the type of effect people are showing. In other words, if*
9 *you -- it will have a tendency to put a larger cost in percentage terms on people who*
10 *make more use of the bulk power system. I think that's a given, the way it's classified.*
11 *So in cents per kilowatt hour basis, it'll cost a little more for residential than industrials.*
12 *But overall, people will tend to pay the same cents per kilowatt hour for Bipole. And as a*
13 *result, the RCC ratios will pull in somewhat, but I don't -- it won't address the greater*
14 *than 10 percent that we're facing"* (Transcript Pages 6103 to 6104).

15
16 Manitoba Hydro notes that Mr. Bowman cites a greater than 10 percent variance based
17 on his alternative approach to calculating class RCC, while the traditional calculation
18 results in an 8.6% variance for GSL > 100 kV and a 9.3% percent variance for the GSL 30
19 – 100 kV class. This alternate calculation has not been endorsed by this Board. It has
20 not been used in PCOSS18 or any other study, and is not the standard measure used in
21 reference to class RCCs. Manitoba Hydro has cautioned elsewhere in this argument that
22 this revised measure of RCC cannot be used without reevaluation of the zone of
23 reasonableness.

24
25 While acknowledging the reasonableness of Manitoba Hydro's evidence, Mr. Bowman
26 remains unconvinced that Bipole III alone will move his clients sufficiently close to unity,
27 suggesting in his direct testimony that previously the "same claims made about
28 Wuskwatim and that did not occur". (Page 45 of Patrick Bowman Pre-filed Testimony on
29 behalf of the Manitoba Industrial Power Users Group, Exhibit MIPUG-13).

30
31 Manitoba Hydro submits that there is no evidence on the record that isolates the
32 impacts of Wuskwatim on class RCC that would confirm Mr. Bowman's assertion. Mr.
33 Bowman is also neglecting to recognize the significant difference in the scale of Bipole III
34 compared to the much smaller Wuskwatim project. The expected impact of a \$5 billion
35 asset (Tab 5 of the Application, Page 19) with no associated incremental revenue can

1 reasonably be assumed to be more consequential than that of a \$ 1.4 billion (Tab 5 of
2 the Application, Page 22) asset which is able to produce offsetting revenues.

3
4 Mr. William Harper also acknowledges and appears to accept the validity of the
5 directional changes expected once Bipole III comes into service in his exchange at
6 Transcript Page 5473.

7
8 The cross examination of Mr. Barnlund at Transcript Pages 2369 to 2370 identifies one
9 further key consideration. The impact of Bipole is significant and immediate, but will be
10 followed by directional consistent impacts in the longer term as Keeyask comes into
11 service.

12 13 **15.2.6 Cost of Service Treatment of Bipole III Reserve Account Revenues**

14 As a percentage of revenue, all customer classes have contributed equally to
15 establishing the Bipole III reserve account. With the upcoming in-service of Bipole III,
16 these funds will be transferred out of the account and the additional revenues will be
17 recognized in the next Cost of Service Study. It is Manitoba Hydro's intention to return
18 the revenue to domestic classes on the same basis by which the revenues were
19 accumulated in the fund - that is equally on an across-the-board basis. It is Manitoba
20 Hydro's view that this approach most fairly apportions the reserve account to each
21 class.

22
23 The alternative treatment of applying the revenues from the reserve account directly
24 against the cost of the Bipole III asset will disproportionately benefit those classes that
25 make relatively greater use of the Generation facilities, notwithstanding that each class
26 has contributed equally to the reserve account.

27
28 Manitoba Hydro has demonstrated the impact of this disproportionate allocation, which
29 would increase the revenue cost coverage ratio of the GSL>100 kV class by one percent
30 (MIPUG/MH-I-23b and MIPUG/MH II-18a-b). For this reason, Manitoba Hydro does not
31 view this as a reasonable alternative for purposes of Cost of Service.

32
33 Manitoba Hydro requests that the PUB provide direction confirming the proposed cost
34 of service treatment of the amortization of the Bipole III Reserve Account in future
35 studies.

1 **15.3 Rate Design**

2 **15.3.1 Residential Rate Design**

3 Manitoba Hydro has applied for rates in this General Rate Application based on its
4 standard rate design. Manitoba Hydro’s Residential rate design is a two-part rate, with
5 a fixed basic charge per month and a single energy charge for all energy consumed in
6 the billing period.

7
8 On September 12, 2017, Manitoba Hydro filed “*A Report on Rate Design for the*
9 *Residential Class*” which included an illustrative residential rate design scenario. The
10 rate design scenario was a residential electric heating rate which would shield electric
11 heating customers from a portion of the proposed rate increase and would require non-
12 heating customers to bear the additional revenue responsibility in order to be revenue
13 neutral within the entire Residential Class. The rate design scenario in that report has
14 not been approved by the Manitoba Hydro-Electric Board, and Manitoba Hydro is not
15 seeking regulatory approval to implement that rate design.

16
17 Rate Design Issues and Policy Considerations

18 In Manitoba Hydro’s view, any modification to the rate design needs to be examined to
19 ensure it is undertaken with full regard and consideration for long standing rate making
20 principles.

21
22 There was much discussion in this proceeding regarding inverted block rates (also
23 referred to as “*inclining block rates*” or “*conservation rates*”). GAC’s expert, Mr.
24 Chernick, provided evidence as to potential inverted block rate designs to be considered
25 for the Residential Class, which included tail block rates priced at approximately 9 cents
26 per kWh.

27
28 However, setting electricity prices at this level for the run-off rate is considerably in
29 excess of the levelized marginal value of electricity of 5.75 cents⁴¹ and would send an
30 inappropriate price signal to customers.

⁴¹ On December 18th, Manitoba Hydro filed an update to PUB/MH II – 57 with the calculation of the levelized marginal values based upon the 2017 Load Forecast and the 2017 Energy Price Forecast and an updated value of generation marginal value. The 2017/18 levelized Marginal Value is approximately 28% lower than the 2015/16 Marginal Value, declining from 7.94 cents (in 2017\$) to 5.75 cents.

1
2 Simply implementing inverted block rates or conservation rates needs to be assessed
3 against the future conditions that may be experienced when Keeyask comes into
4 service. The significant change in marginal value from 7.9 cents to 5.7 cents should be
5 heeded.

6
7 Mr. Barnlund discussed this point with Mr. Gange at Transcript Pages 3063 and 3064:

8
9 *“I think we need to look at the question of rate design and considering some of the*
10 *issues we’ve got with electric heat customers, with low income customer with the*
11 *potential photovoltaics coming out of the system, and I would add to that the*
12 *information we talked about this morning where the marginal value of energy, if we*
13 *– if we strictly look at which is being – being calculated, suggests that you would be*
14 *looking to a declining block rate and not an inclining block rate.”*

15
16 *“So, I think that with all due respect, Mr. Gange, we find ourselves in far different*
17 *circumstances today than we did in 2003, or 2008, 2009, and I think that we have to*
18 *be alive to that change in circumstances, and we have to be intelligent terms of how*
19 *we proceed with this.”*

20
21 *“We should be looking at the conditions of the present and the conditions of the*
22 *future in terms of how we proceed.”*

23 24 Mr. Chernick’s Rate Proposal Has Serious Shortcomings

25 In Exhibit GAC-11, GAC’s expert Mr. Chernick provided a rate design proposal which
26 comprised four separate residential rate designs, including a LICO-125 electric heating
27 rate, a LICO-125 non-heating rate, a non-LICO 125 conservation rate and non-LICO 125
28 electric heating rate. Each rate design had the size of the first block differentiated by
29 four seasons (summer, fall, winter, spring). The LICO-125 rates also included the
30 elimination of the monthly basic charge and the inclusion of a sharp price discount for
31 the initial block of usage.

32
33 Manitoba Hydro requested that Mr. Chernick provide Proof of Revenue Statements for
34 all of his proposed rate designs (MH/Chernick I – 10) in order for Manitoba Hydro to
35 assess whether the proposed combination of basic charges, waivers of basic charges,

1 discounts to first block usage, seasonal block size variations and the recovery rate from
2 non-LICO 125 customers would produce the required revenues as sought by Manitoba
3 Hydro from the Residential Class in this Application. Unfortunately, Mr. Chernick did not
4 conduct this analysis, as noted in his response to that Information Request.
5 Furthermore, under cross examination from PUB Counsel at Transcript Oage 3836, Mr.
6 Chernick stated:

7
8 *"I don't believe that I – I've located the necessary data, and I wasn't able to provide the*
9 *analysis."*

10
11 Manitoba Hydro provides a Proof of Revenue Statement in each rate application to
12 verify that the combination of rates and charges when applied to the test year load
13 forecast, generates the expected level of revenue by customer class. As Mr. Chernick
14 has not undertaken such an analysis, it is impossible to test his rate design proposal to
15 ensure it produces the appropriate level of revenue, and therefore no weight can be
16 given to his propose rate designs.

17 18 **15.3.2 Rate Design for General Service Large Customer Classes**

19 Time of Use Proposal

20 In his pre-filed evidence at pages 7-14 to 7-16, Mr. Patrick Bowman for MIPUG discusses
21 the RCC outcomes for the GSL>100 class and proposes that Manitoba Hydro implement
22 a time of use rate structure on an "optional" basis for that customer class.

23
24 His optional time of use rate design references the illustrative Time of Use ("TOU") rate
25 scenarios previously prepared by Manitoba Hydro which were based upon revenues and
26 billing determinants for August 1, 2016 rates. Under Mr. Bowman's proposal, both
27 standard and TOU rates would be designed for the GSL>100 class and each of the 14
28 customers in the class would have the option to choose from either the standard rate
29 design or the TOU rate design.

30
31 In his direct evidence testimony at Transcript Page 6106, Mr. Bowman states that time
32 of use rates help make the rates within a class fairer, even if customers don't shift load.
33 The "fairness" of a time of use rate design within a given customer class is an
34 appropriate point to make when considering the reduction of cross subsidy between
35 customers within any given class. For customers within the GSL > 100 kV class, the

1 degree of cross subsidy between customers depends upon their individual usage
 2 characteristics.

3
 4 Based on each GSL > 100 kV customers actual usage characteristics, the annual bill
 5 impact to each of those customers was shown in the response to MIPUG/MH I-5c and
 6 on Page 71 of Manitoba Hydro’s Written Rebuttal Evidence, Exhibit MH-52, which is
 7 provided below.

8
 9 **Figure 15.3**

	Bill Impact of TOU vs Standard GSL > 100 Rate Design (\$)	Customer under TOU rate design
Customer 1	900,200	Higher bill
Customer 2	438,500	Higher bill
Customer 3	140,300	Higher bill
Customer 4	114,700	Higher bill
Customer 5	39,500	Higher bill
Customer 6	36,800	Higher bill
Customer 7	400	Higher bill
Customer 8	(29,700)	Lower bill
Customer 9	(70,800)	Lower bill
Customer 10	(96,900)	Lower bill
Customer 11	(103,800)	Lower bill
Customer 12	(221,500)	Lower bill
Customer 13	(294,400)	Lower bill
Customer 14	(711,000)	Lower bill
7 customers	\$ (1,528,100)	Lower revenues - TOU
7 customers	\$ 1,670,400	Higher revenues - TOU

10
 11
 12 Mr. Bowman states that a time of use rate design has better fairness attributes than the
 13 existing rate design. The data in the above table compares annual bills under both a
 14 time of use and the standard rate design. This analysis demonstrates that customers 1
 15 through 7 are not fully covering the cost to serve them under the standard GSL > 100 kV
 16 rate design, as they would be paying higher bills under the time of use rate design.
 17 Therefore, as Mr. Bowman observes, a time of use rate design would “*make the rates*
 18 *within a class fairer*”, indicating that Customers 1 through Customer 7 are currently
 19 being cross subsidized by Customers 8 through Customer 14 in the GSL > 100 kV class.

1 Manitoba Hydro's concerns with providing a standard rate design and an optional time
2 of use rate centres on the issue of total revenue collection, in the event that only half of
3 the customers opt for the time of use rate, leaving the higher cost customers on the
4 standard rate design. This situation opens the door to self-selection by customers,
5 based solely on their potential to benefit from one rate design or the other.

6
7 The result of the potential self-selection by GSL > 100 customers is that only customers
8 whose bills could be lower under the time of use option would switch rates and
9 therefore Manitoba Hydro would see a revenue shortfall of approximately \$1.5 million
10 for the GSL > 100 class as shown in the table above.

11
12 Mr. Bowman acknowledges the revenue losses of approximately \$1.5 million on Page 7-
13 15 of Exhibit MIPUG-13.

14
15 On page 7-16 of Exhibit MIPUG-13, Mr. Bowman suggests that the current RCCs of the
16 GSL>100 kV class could drop with the implementation of optional TOU rates and no
17 further recovery of the lost revenues.

18
19 The appropriate level of revenues should be explicitly dealt with by viewing the class by
20 class RCC outcomes of PCOSS18 and determining whether there should be any
21 deliberate shift in revenue responsibility between rate classes, prior to designing tariffs
22 at the rate design stage.

23
24 In other words, if the likely outcome of an optional TOU rate offering is a net reduction
25 of revenues of \$1.5 million, that revenue must be made up either from other non-
26 participating GSL>100 kV customers, by increasing the level of the standard rate, or it
27 must be made up from customers in other rate classes.

28
29 In cross-examination by PUB Counsel on January 25, at Transcript Pages 6457 to 6459,
30 Mr. Bowman discusses his recommendation on the matter of a Time-of-Use rate design.
31 In his exchange, beginning on Transcript Page 6458, Mr. Bowman states:

32
33 *"My – my suggestion to the Board is that it – t indicate to Hydro that – that work should*
34 *be done on an – creating a new rate schedule available to at least the largest two (2)*
35 *classes of customers. And that that rate schedule should be one (1) that customers can*

1 *opt into, but need not be required to move into. That rate schedule would not change the*
2 *fact that they're in the overall class for the purposes of setting RCCs, so if there is less*
3 *revenue it would affect the – it would affect the class in the cost of service study.”*
4

5 Mr. Bowman’s recommendation suggests that Manitoba Hydro should not be
6 compensated for any revenue loss caused by the self-selection of customers under an
7 optional rate offering scheme. This recommendation violates Manitoba Hydro’s rate
8 making objective of full recovery of the revenue requirement, and furthermore violates
9 Bonbright’s criteria of “*effectiveness of yielding total revenue requirements*”.

10 11 **15.3.3 The Relevance of Demand Charges in Rate Design**

12 Mr. Chernick, at pages 39 to 42 of Exhibit GAC-11, advises the PUB to consider reducing
13 or eliminating demand charges in the design of rates for general service customers.
14

15 Contrary to Mr. Chernick’s opinion, demand charges provide a meaningful price signal to
16 general service customers, in that electricity service consists of both the supply of
17 energy and the provision of capacity to meet those customers’ peak load requirements.
18 Distribution feeders, substations, sub-transmission and transmission facilities are
19 designed to accommodate the planned peak loads on the system, and the Corporation is
20 contractually obligated to serve customers to the level of their required peak demand.
21

22 In addition, demand charges also provide the Corporation with a greater degree of
23 revenue stability, which is also an important rate making consideration.
24

25 Demand charges give customers a price signal as to the cost of the capacity
26 requirements that they impose on the system, the information to make better decisions
27 around the management of peak demand, and an incentive to manage these peak
28 demands. Without such an incentive, customers may place greater demand on the
29 system than they would otherwise, which can result in increased capacity requirements
30 on the system and increased costs to be borne by all customers.
31

32 On pages 42 and 43 of Exhibit GAC-13, Mr. Chernick expresses his view that Manitoba
33 Hydro should eliminate demand ratchets or minimum billing demand provisions from its
34 GSM and GSL tariffs.
35

1 The monthly billing demand for General Service Medium (over 200 kVA) and General
2 Service Large customers is the greater of either (Appendix 9.3 (Updated) of the
3 Application, Page 10-11):

- 4 1. measured demand; or
- 5 2. 25% of the contract demand; or
- 6 3. 25% of the highest measured demand in the previous 12 months.

7
8 Mr. Chernick has several criticisms of demand charges on page 43 of his evidence. He
9 suggests that demand ratchets and contract demand provisions provide no incentive to
10 reduce energy usage in low demand months (under 25% of the highest measured
11 demand in the previous 12 months) and excessively penalize customers for marginal
12 usage in the highest demand months, which in his view provides confusing and
13 misleading price signals.

14
15 However, minimum billing demand and contract demand provisions reinforce the price
16 signal to customers of the cost of demand that they impose on the Manitoba Hydro
17 system. The cost of capacity and energy are shown separately on bills and customers
18 can assess these costs in making their electricity usage decisions. In addition, contract
19 demand provisions also encourage customers to more carefully assess their capacity
20 requirements when adding load to the system. Without contract demand provisions,
21 customers may contract for excess capacity on the possibility that it may be needed in
22 the future. This capacity must then be constructed and reserved for that customer, and
23 a contract demand provision provides for some level of ongoing revenue recovery for
24 that additional capacity.

25
26 Lastly, Mr. Chernick suggests that demand bill impacts may arise for customers who
27 unintentionally establish a new maximum contract demand. Manitoba Hydro notes that
28 customers that inadvertently set a new maximum demand level may contact a customer
29 representative to explain their specific circumstances and potentially have their billing
30 demand level reviewed and adjusted, and therefore may not pose the bill impacts to
31 customers as Mr. Chernick has suggested.

1 **16 RATE SHOCK**

2 **16.1 Manitoba Hydro's Rate Request Does Not Represent Rate Shock**

3 As noted by Mr. Barnlund on Transcript pages 2386 and 2387, Manitoba Hydro has, in
4 fact, mitigated the level of rate increases that would otherwise be caused by the in-
5 service of the Bipole III Reliability Project, the Keeyask Generating Station and the U.S.
6 Interconnections comprised of the Manitoba-Minnesota Transmission Project and the
7 Great Northern Transmission Line. In Order 73/15, the Public Utilities Board of
8 Manitoba ("PUB") provided a table on page 7, reproduced below, which indicated the
9 impact to revenue requirements of these new facilities entering service.

10
11 **Figure 16.1. Revenue Requirement Impact (from Order 73/15)**

The following table illustrates Manitoba Hydro's new revenue requirements attributable to new major projects, starting in 2019:

Revenue Requirement Impacts (\$ Million)

Year Ending March 31	2019	2020	2021	2022
Bipole III Transmission Reliability Project	234	384	382	377
Keeyask Generating Station	28	80	316	462
Manitoba/Minnesota Transmission Project / Great Northern Transmission Line	1	5	85	115
Conawapa Sunk Costs	35	34	34	33
Additional Annual Revenue Required for New Projects	298	503	817	987
Cumulative Indicative-Only Annual Rate Increase Required to Pay New Costs	20%	34%	54%	65%

Sources: Application Appendix 11.15, Exhibit MH-118

12
13 **Source: Page 7 of PUB Order 73/15**

14
15 The increases in revenue requirement due to incremental depreciation, finance
16 expense, capital tax and Operations & Maintenance associated with new major projects
17 entering service would result in unmitigated rate increases of 20% in 2019, 34% in 2020,
18 54% in 2021 and 65% in 2022, if those costs were passed directly through to customers
19 as that plant became used and useful. Unlike most other utilities that are regulated on a
20 rate-base, rate-of-return basis, Manitoba Hydro is regulated under a cost of service
21 approach that facilitates a more gradual smoothing into customer's rates of these lumpy
22 increases in revenue requirement.

1 Given the extent of the unmitigated rate increases that would otherwise be necessary
2 given the significant costs incurred with the in-service of these major projects, Manitoba
3 Hydro's request of a 7.9% increase on April 1, 2018 demonstrates the significant rate
4 impact mitigation that Manitoba Hydro is affording its customers through this time
5 period.

6
7 The Consumer Coalition, MIPUG and the GSS/GSM-KAP representatives have
8 characterized the rates requested in this General Rate Application as constituting "rate
9 shock". Manitoba Hydro does not agree with this characterization, as discussed by Mr.
10 Barnlund at Transcript Page 1469:

11
12 *"MR. GREG BARNLUND: ... We would not consider 7.9 percent rate*
13 *increases to be -- meeting a threshold of rate shock.*

14
15 *Typically utilities and utility boards consider a threshold of 10 percent. In*
16 *2004 this utilities board looked at Manitoba Hydro's application for*
17 *August 1 rates and they considered a definition of rate shock or discussion*
18 *of rate shock at that particular hearing. And they found that as long as*
19 *the increases were no more than 8 or 9 percent that they would not be*
20 *considering those as rate shock.*

21 ...

22
23 *MR. GREG BARNLUND: While it's a difficult increase it's not rate shock*
24 *because rate shock also infers a sudden surprise on customers and*
25 *Manitoba Hydro has been very clear in terms of its communication of its*
26 *financial situation, and indicating that there would be a need for*
27 *continual rate increases of this order of magnitude."*

28
29 The reference to 2004 in the excerpt above is in respect of Manitoba Hydro's rate
30 application filed on January 29, 2004. In that application, Manitoba Hydro applied for
31 general rate increases of 3.0% to be effective April 1, 2004 and 2.5% to be effective on
32 April 1, 2005.

33
34 The subject of rate shock was examined by the PUB in its review of that rate application
35 which resulted in the PUB issuing Order 101/04 on July 28, 2004. The PUB granted

1 Manitoba Hydro a 5.0% increase (a full 2.0 % greater than requested by the corporation
2 in its initial filing) for August 1, 2004 and a further 2.25% on a conditional basis for April
3 1, 2005 and 2.25% on a conditional basis for October 1, 2005.

4
5 In that Order, on page 27, the PUB noted:

6
7 *In coming to a decision on the rate increases, firm and conditional, the Board*
8 *considered the issue of rate shock, and opines that the rate increases for most*
9 *customers will be within the thresholds put forth by the Intervenors (i.e. no more*
10 *than 8-9% for any customers for the August 1, 2004 increase, and much less for*
11 *most).*

12
13 Mr. Barnlund also raised the matter of the increases previously granted to Centra Gas
14 Manitoba Inc. by the PUB in regards to natural gas rates. In Transcripts pages 2013 and
15 2014, in response to questions by Mr. Monnin on behalf of GSS/GSM-KAP, Mr. Barnlund
16 testified:

17
18 *I might, I guess, draw your attention though to some of the decisions*
19 *that this Board has made with respect to the natural gas utility, Centra*
20 *Gas Manitoba Inc., which of course deals with a much more volatile cost*
21 *structure due to the fact that a great deal of the cost as passed on to*
22 *customers is a cost of gas that's procured in the wholesale market.*

23
24 *And there's been ten (10) at least – or ten (10) occasions where this*
25 *Utilities Board has approved increases to natural gas customers in excess*
26 *of 10 percent. And a situation in 1999 and 2000 when wholesale*
27 *commodity prices really increased at a – at a very fast pace, the Utility*
28 *Board passed through an increase of upwards of 25 percent on one (1)*
29 *occasion.*

30
31 Mr. Barnlund further testified at Transcript pages 2014 and 2015, in response to
32 questions from Mr. Monnin:

33
34 *And – and you were asking me about the surprise to customers. And*
35 *certainly some of the gas rate increases that have been approved by this*

1 *Board were driven by some surprising changes in the wholesale market*
2 *where there is relatively little notice that was provided to customers of*
3 *those changes. And that was more of an issue of rate shock to be*
4 *contended with than what we are certainly referring to here in this*
5 *General Rate Application, sir*
6

7 Regulators in Ontario and Alberta have identified a threshold of 10 percent as being an
8 indication of rate shock or a level of rate increase that may require the utility to provide
9 a rate mitigation plan to accompany its rate filing as discussed by Mr. Barnlund at lines 1
10 through 7 on Transcript page 2108.

11
12 Manitoba Hydro's proposed rate increase for 2018/19 of 7.9% is less than the 10%
13 threshold identified in other jurisdictions, is less than the 8% - 9% threshold mentioned
14 by the PUB in Order 101/04, and is far less than the unmitigated impact to revenue
15 requirement that would otherwise be experienced as Major New Generation and
16 Transmission projects come into service over the coming years.

1 **17 REGULATORY DEFERRAL ACCOUNTS AND INTERIM APPROVALS**

2 **17.1 Regulatory Deferral Accounts**

3 Under International Financial Reporting Standards (“IFRS”), financial statements must
4 reflect the impacts of regulatory decisions with respect to timing differences for the
5 recognition of revenue/expenses for rate setting purposes as compared to financial
6 reporting purposes (e.g. \$20 million of overhead expensed for financial reporting and
7 deferred for rate setting). When performing the audit of Manitoba Hydro’s financial
8 statements, Manitoba Hydro’s external auditor will review the content found in Public
9 Utilities Board of Manitoba (“PUB”) Orders to validate the accounting for regulatory
10 deferrals as presented in the Corporation’s financial statements.

11
12 Manitoba Hydro is seeking PUB endorsement of the following, pertaining to various
13 deferral accounts:

- 14 • The proposed deferral and subsequent amortization for the costs incurred with
15 respect to the Conawapa Generating Station as discussed in Tab 3 (page 18) of this
16 Application;
- 17 • The proposed amortization period for the disposition of the regulatory deferral
18 account established to capture the annual difference (\$20 million) between
19 overhead costs expensed for financial reporting purposes based on IFRS and
20 overhead costs expensed for rate setting purposes reflecting Order PUB 73/15;
- 21 • The proposed amortization period for the disposition of the regulatory deferral
22 account established to defer gains and losses on the disposition of assets; and
- 23 • The proposed time frame for the recognition into revenue of the Bipole III deferral
24 account.

25
26 Manitoba Hydro’s preference is to have a single basis of depreciation for both financial
27 reporting and rate setting purposes thereby eliminating the need for a deferral account.
28 This would address Manitoba Hydro’s concerns with respect to the excessive growth in
29 the deferral account balance, as well as reduce the ongoing administrative cost and
30 effort to maintain the deferral indefinitely as the calculation of the deferral will become
31 more complex over time.

32
33 However, Manitoba Hydro recognizes that for a single basis of depreciation to apply, the
34 PUB’s directives from Order 43/13 must be addressed. Given the specialized and
35 technical nature of this subject matter, Manitoba Hydro is supportive of finding an

1 alternate process where the requirements of the depreciation directives can be
2 discussed and resolution of this issue can be achieved. Manitoba Hydro is also
3 supportive of finding an alternate process where the issue of the indefinite deferral of
4 ineligible overhead can be discussed in more detail.

6 **17.1.1 Conawapa Generating Station**

7 Manitoba Hydro has incurred approximately \$380 million in costs pertaining to the
8 construction of the Conawapa Generating Station (Exhibit MH-127). A decision has been
9 made to discontinue any further development of the station at this time. As a result,
10 the Corporation is anticipating to write-down these costs to net income in 2017/18 as
11 per Ms. Bauerlein's oral testimony on Transcript Page 765:

12
13 *Things have changed. We will have to have discussions with our auditor*
14 *this upcoming March 2018 to assess whether or not that this asset will be*
15 *viewed as what we call a stranded asset, and would therefore have to be*
16 *written off. Based on things that happened over the last several months,*
17 *we believe that is a strong possibility.*

18
19 Manitoba Hydro is seeking the PUB's endorsement of its proposal to record the costs
20 pertaining to the construction of the Conawapa Generating Station in a regulatory
21 deferral account effective March 2018 and commence amortization of the costs to
22 income on a straight line basis over a period of 30 years beginning April 1, 2018, in order
23 to minimize the impact on customers.

24
25 At pages 49-50 of Mr. Harper's Evidence, filed as Consumers Coalition Exhibit CC-20, Mr.
26 Harper provides endorsement of Manitoba Hydro's proposed accounting treatment
27 with respect to Conawapa construction costs, stating that "*Since the decision dealt with*
28 *the most appropriate way to meet Manitoba Hydro's energy needs over a long-term*
29 *planning horizon, the write-off can be viewed as part of the overall cost of implementing*
30 *the Board's decision. Overall, the 20 year period is reasonable.*"

31
32 It is noted that in oral testimony (Transcript Page 5186 and 5187), Mr. Harper corrected
33 his written evidence referencing the 20 year amortization period to a 30 year
34 amortization period consistent with Manitoba Hydro's proposal.

1 **17.1.2 Depreciation Methodology**

2 Manitoba Hydro adopted the Equal Life Group (“ELG”) method of depreciation to be
3 compliant with the financial reporting requirements of IFRS. This change resulted in an
4 initial annual increase in depreciation expense of approximately \$30 million compared
5 to the CGAAP Average Service Life (“ASL”) method of depreciation used by Manitoba
6 Hydro prior to IFRS. Notably, over the service life of an asset, the total depreciation will
7 be the same under either method.

8
9 In Order 43/13, the PUB directed Manitoba to perform the following:

10
11 *8. That Manitoba Hydro file updated depreciation rates and schedules based on*
12 *an International Financial Reporting Standards-compliant Average Service Life*
13 *methodology with the next General Rate Application.*

14
15 *9. That Manitoba Hydro file with the Board, with the next General Rate*
16 *Application, a chart showing a comparison of the impact on its Integrated*
17 *Financial Forecast (i.e. ‘Budget’) of asset depreciation pursuant to the Average*
18 *Service Life methodology (without net salvage) and the Equal Life Group*
19 *methodology (without net salvage), applying both methodologies to all planned*
20 *major capital additions.*

21
22 In Directive 10 of Order 73/15, the PUB further directed Manitoba Hydro to continue to
23 use the CGAAP-ASL method of depreciation for rate setting purposes until the PUB is
24 satisfied that a change in depreciation methodology is warranted.

25
26 As indicated in Tab 10 of the GRA, Manitoba Hydro has addressed the requirements of
27 Directive 10 of Order 73/15 by deferring the difference between depreciation expense
28 calculated for financial reporting purposes (based on IFRS-compliant ELG depreciation
29 rates) and depreciation expense calculated for rate-setting purposes (using CGAAP-
30 compliant ASL depreciation rates) in a regulatory deferral account. As required by IFRS
31 14, Manitoba Hydro is also making a corresponding adjustment through the net
32 movement in regulatory balances account such that for rate setting purposes, Manitoba
33 Hydro’s revenue requirement for the test years continues to reflect depreciation
34 expense based on CGAAP-compliant ASL depreciation rates. Although a deferral account

1 has been established, Manitoba Hydro is not seeking approval of the amortization
2 period for the differences in the depreciation methodology at this time.

3
4 Manitoba Hydro notes that a change in methodology was required in order to be
5 compliant with IFRS and it is expected that an increase in depreciation expense would
6 have occurred regardless of whether Manitoba Hydro used IFRS compliant ELG or ASL
7 depreciation rates.

8
9 As an initial means to offset the impact of the change to the ELG method, Manitoba
10 Hydro eliminated the recognition of negative salvage in depreciation rates which
11 reduced depreciation expense by approximately \$50 million per annum. This change
12 more than offset the \$30 million annual increase that resulted from the change to the
13 ELG method.

14
15 Manitoba Hydro's preference is to have a single basis of depreciation for both rate
16 setting and financial reporting purposes. A single basis of depreciation would have the
17 benefit of eliminating the need for a deferral account and address Manitoba Hydro's
18 concerns with respect to the excessive growth in deferral account balances (\$1.9 billion
19 by 2035), as evidenced in the response to PUB/MH I-1b. The corporation is concerned
20 that such balances will need to be absorbed by future rate payers in addition to other
21 risks (e.g. drought, reduced export prices) that may also arise. A single basis of
22 depreciation will also reduce the ongoing administrative cost and effort to maintain the
23 deferral indefinitely as the calculation of the deferral will become more complex over
24 time as Manitoba Hydro continues to add and replace assets.

25
26 However, Manitoba Hydro recognizes that for a single basis of depreciation to apply, the
27 PUB's directives from Order 43/13 must be addressed. Manitoba Hydro is supportive of
28 finding an alternate process where the requirements outlined in the depreciation
29 directives issued by the PUB can be discussed in more detail and a resolution of this
30 issue can be achieved. Having an alternative process would allow Manitoba Hydro to
31 provide the PUB with the information necessary to move forward with respect to the
32 depreciation methodology issues. This is aligned with the recommendations of Mr.
33 Harper's oral testimony at Transcript Pages 5219 to 5220 where he states:

1 *The Board's directive also called for Manitoba Hydro to return with the necessary*
2 *information to permit it to make a determination as to which depreciation --*
3 *while -- methodology should be used for rate -- rate setting. Assuming Manitoba*
4 *Hydro intends to comply with the directive in a timely fashion, there is no need, in*
5 *my view, to either, 1) amortize the current balance, or -- or establish a date after*
6 *which the cost differences between the two (2) will no longer be deferred. These*
7 *matters can better be addressed by the Board after it has determined what is the*
8 *appropriate depreciation methodology for rate-setting purposes.*

9
10 As noted above, Manitoba Hydro has established a deferral account to capture the
11 difference between depreciation expense calculated based on IFRS-compliant ELG
12 depreciation rates and CGAAP-ASL rates. While an assumption has been included in the
13 current integrated financial forecast to amortize the deferral balance for rate setting
14 purposes over a period of 20 years beginning in 2019/20, Manitoba Hydro believes that
15 a more appropriate course of action would be to convene a process to review and
16 consider the depreciation directives outside of a GRA process and before 2019/20.

17 18 **17.1.3 Ineligible Overhead**

19 Upon its transition to IFRS, Manitoba Hydro reduced the extent of overhead costs
20 capitalized in property, plant and equipment to bring its capitalization policies in line
21 with other Canadian utilities and to comply with the financial reporting requirements of
22 IFRS. In the PUB findings on page 35 of Order 73/15, the PUB did not accept for rate
23 setting purposes expensing an additional \$20 million in annual overhead costs that were
24 deemed ineligible for capitalization under IFRS and found instead that these additional
25 overhead costs should continue to be capitalized, consistent with the practices used by
26 Manitoba Hydro prior to its transition to IFRS.

27
28 As outlined in Tab 3 of the Application, Manitoba Hydro has established a regulatory
29 deferral account to capture the \$20 million in annual overhead costs that are ineligible
30 for capitalization under IFRS. This deferral facilitates compliance with the PUB's
31 direction in Order 73/15. As shown in MH16 Update with Interim, the balance in this
32 deferral account grows to approximately \$160 million by 2022/23.

1 Manitoba Hydro is seeking PUB endorsement of its proposal, as outlined in Tab 3, to
2 amortize the balance in this deferral account over a 20 year period, beginning in
3 2017/18.

4
5 Intervenors to this application, specifically Mr. Bowman and Mr. Harper, have argued
6 that the amortization period for the ineligible overhead costs should be extended to a
7 30 year period. As discussed by Manitoba Hydro on page 38 of Exhibit MH-52, while
8 extending the amortization period for regulatory deferrals will result in a reduction to
9 amortization expense and a subsequent increase to net income and retained earnings,
10 such increases are based on a reduction to a non-cash related expense (i.e. amortization
11 expense). The scenario provided by Manitoba Hydro in Appendix 3.1 of Exhibit MH-52
12 incorporates the recommendations of Mr. Bowman including: i) continuation of both
13 the overhead and ELG/ASL deferrals through the forecast period; ii) extension to the
14 amortization period of the overhead deferral to 30 years; and iii) no amortization of the
15 ELG/ASL depreciation deferral.

16
17 The results of this analysis indicate that requested rate increases would marginally
18 decrease by 0.26% from the 7.9% requested to 7.64% per year over the 6 year period
19 from 2018/19 through to 2023/24. This marginal decrease is due to the fact that
20 reductions to non-cash expenses have no impact on cash flows and as a result, do little
21 to reduce debt levels. This fact is acknowledged by Mr. Bowman on page 6-10 (lines 17-
22 18) in Exhibit MIPUG-13 as he states, *"The adjustment will not directly improve nor harm*
23 *Hydro's cash flows, as deferral and amortization is a non-cash adjustment."* Consistent
24 with Manitoba Hydro's responses to MIPUG MFR 5, PUB/MH I-1b and PUB/MH II-2a-c,
25 the analysis demonstrates that 7.9% rate increases are required as a result of growing
26 debt levels and a deterioration in cash flows and are not resolved through accounting
27 changes related to the amortization periods of regulatory deferral accounts.

28
29 Manitoba Hydro notes that in Order 73/15, the PUB did not provide any direction with
30 respect to how long Manitoba Hydro should continue to capitalize the additional
31 overhead costs. Manitoba Hydro is concerned that an indefinite deferral is not
32 appropriate given that there is no impact to net income by the end of the amortization
33 period. As such, it is not clear what the benefit to the ratepayer would be in deferring
34 such costs into perpetuity. Regardless of the amortization period used for the ineligible
35 overhead, the annual amortization of the deferral account charged to net income will

1 equate to the annual deferral amount of \$20 million by the end of the amortization
2 period. For example, if a 20 year amortization period is used, by year 21, the annual
3 deferral amount of \$20 million will equate to the annual amortization of \$20 million
4 such that the net income impact will be zero. This impact on net income holds true
5 regardless of the amortization period used.

6
7 Manitoba Hydro is also supportive of finding an alternate process where the issue of the
8 indefinite deferral of ineligible overhead can be discussed in more detail. Mr. Harper is
9 supportive of the need for further clarity on this issue as he states on page 46 of Exhibit
10 CC-46:

11
12 *Manitoba Hydro's comments suggest that the Board's decision to defer ineligible*
13 *overheads (and ELG/ASL depreciation differences) was based on rate smoothing*
14 *considerations. However, it is not clear that this was the case. In the case of*
15 *ineligible overheads, the Board's Decision appears to reflect a view that the level*
16 *of overheads identified in the proceeding prior to the 2015/16 and 2016/17 GRA*
17 *were the appropriate level to capitalize for rate-setting purposes. However, at*
18 *the end of the day, it remains for the Board to confirm what its objective was in*
19 *deferring the \$20 M of ineligible overheads. If the Board was/is of the view that*
20 *the \$20 M is more appropriately capitalized, then there is no basis for ceasing the*
21 *deferral after 2022/23.*

22 23 **17.1.4 Gains and Losses on the Disposition of Assets**

24 As explained by Ms. Bauerlein in direct evidence starting on Transcript Page 678,
25 Manitoba Hydro is proposing that asset retirement gains and losses be deferred in a
26 regulatory account and amortized on a straight-line basis over a period of 20 years for
27 rate setting purposes. The proposal is consistent with the PUB findings in Order 73/15
28 (page 45) where the PUB ordered Manitoba Hydro to continue to determine
29 depreciation expense based on its existing CGAAP-compliant ASL methodology for rate
30 setting purposes. Under the CGAAP ASL method, Manitoba Hydro deferred and
31 amortized the recognition of gains and losses on the disposition of assets by recognizing
32 them initially in accumulated depreciation and subsequently amortizing these amounts
33 over the remaining lives of the respective assets via an adjustment to future
34 depreciation rates. This CGAAP form of accounting is not consistent with IFRS which
35 requires asset retirement gains and losses to be recognized immediately to net income

1 in the year incurred. As such, Manitoba Hydro requires a regulatory deferral account to
2 record these amounts in order to continue to defer and amortize asset retirement gains
3 and losses for rate setting purposes.
4

5 Consistent with other regulatory deferral accounts, Manitoba Hydro requires
6 endorsement from the PUB as to the 20 year amortization period it is proposing in its
7 Application. Manitoba Hydro notes that Mr. Harper agrees with the proposed
8 accounting treatment of Manitoba Hydro as he states on page 41 of his written
9 evidence, *“As noted earlier, in such situations the choice of amortization period is a
10 matter of judgment. Since an amortization period of 20 years is likely to achieve a result
11 similar to that experienced prior to the implementation of IFRS, the period appears
12 reasonable.”*
13

14 **17.1.5 Bipole III Revenue Deferral**

15 The Bipole III reserve account was established by Manitoba Hydro, consistent with the
16 direction provided by the PUB in Order 43/13 (directive #3, page 4) which stated that:
17

18 *That a 3.5 % overall increase in billed rates for the basic monthly charge, the*
19 *demand charge, and the energy charge for all rate categories to take effect May*
20 *1, 2013, with revenues from a 1.5% portion of the rate increase accruing in a*
21 *deferral account to be utilized to mitigate the required rate increases when*
22 *Bipole III is placed in-service, **BE AND IS HEREBY APPROVED.***
23

24 The rationale provided by the PUB for establishing the Bipole III deferral account is
25 documented on page 10 of Order 43/13:
26

27 *The capital deferral account is to assist in funding the planned Bipole III*
28 *transmission line. The cost of this project will be capitalized during the*
29 *construction phase, but significant annual depreciation, operation, maintenance*
30 *& administration, and interest costs will have to be recovered from domestic*
31 *ratepayers once the project is placed in-service. The deferral account allows*
32 *Manitoba Hydro to collect funds as the Bipole III project is being built, which will*
33 *help to mitigate rate increases required once the infrastructure is placed in-*
34 *service.*
35

1 As shown in Appendix 3.8, MH16 Update with Interim, as at March 31, 2017, cumulative
2 revenues accrued to the Bipole III deferral account are \$196 million reflecting rate
3 increases received by Manitoba Hydro since 2014 that were directed to the Bipole
4 deferral. The Bipole III deferral account is projected to grow to approximately \$400
5 million by the Bipole III planned in-service date of July 2018. The MH16 Update with
6 Interim forecast assumes that the deferral account is recognized in domestic revenues
7 over a five year period following the Bipole III project in-service date (effective August
8 2018) through to July 2023 to coincide with the final in-service date of the Keeyask
9 generating station. A five year period over which to recognize the deferred revenue was
10 chosen so as to help mitigate the initial expected increases in annual depreciation,
11 interest and operating costs following the in-service of the Bipole III project.
12 Subsequent to the 2023 period, additional export revenues from the Keeyask project
13 will be available to help offset such charges and therefore, no further recognition of the
14 deferral is required following that date.

15
16 Manitoba Hydro notes that the timing of the recognition of the revenue will not impact
17 the future cash flows of the Corporation as the money has already been received via
18 previous year's rate increases/revenue collected. As explained by Mr. McCallum in his
19 oral testimony, at Transcript Page 751:

20
21 *I think the really important thing to appreciate here is that this is a – this is*
22 *accounting rules dictating the recognition of revenue. The cash has already been*
23 *paid. It's in the bank or its been spent,..., There's no incremental cash benefit*
24 *that comes from this \$400 million balance which we amortize. This is a*
25 *recognition item. It's an accounting policy item.*

26
27 In addition to the comments of Mr. McCallum, Manitoba Hydro further notes that the
28 revenues collected by way of the Bipole III deferral account have been included in equity
29 balances when determining actual and projected debt-equity ratios of the corporation.
30 As such, the timing of when the revenue is recognized into net income will not change
31 the cash/debt position or equity ratio of Manitoba Hydro going forward and will
32 therefore have no impact on customer rates.

33
34 The following continuity schedule in **Figure 17.1** displays the annual contributions and
35 proposed drawdowns of the Bipole III reserve account by fiscal year:

1
2
3
4
5
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Figure 17.1 Bipole III Reserve Account Reconciliation

Bipole III Reserve Account Reconciliation
(In thousands of dollars)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Opening balance	-	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605
Contributions	18 825	30 249	51 204	96 018	151 017	51 739	-	-	-	-	-
Drawdowns	-	-	-	-	-	(53 207)	(79 810)	(79 810)	(79 810)	(79 810)	(26 605)
Ending balance	18 825	49 074	100 278	196 296	347 313	345 845	266 035	186 225	106 415	26 605	-

Source: PUB/MH I-152b

Given that the Bipole III project is expected to go into service in July 2018 of the upcoming test year, Manitoba Hydro is seeking direction from the PUB as part of its Order issued in response to Manitoba Hydro’s GRA as to the amortization period over which to recognize the revenues deferred in the Bipole III account.

17.2 Interim Orders

Manitoba Hydro has attached, as Appendix 17.1, a complete list of interim and ex parte Orders that require final approval by the PUB.



Second Session - Thirty-Seventh Legislature

of the

Legislative Assembly of Manitoba

**DEBATES
and
PROCEEDINGS**

**Official Report
(Hansard)**

*Published under the
authority of
The Honourable George Hickes
Speaker*



Vol. LI No. 38 - 1:30 p.m., Wednesday, May 30, 2001

MANITOBA LEGISLATIVE ASSEMBLY
Thirty-Seventh Legislature

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TWEED, Mervin	Turtle Mountain	P.C.
WOWCHUK, Rosann, Hon.	Swan River	N.D.P.

and farmers to discuss the economic disaster that is currently going on in the oilseed and grain seed sector, one would have given some praise to the Prime Minister. Yet people and farmers, a group of farmers that asked for an audience with him were told that if they paid \$350 per plate for a dinner they might get to say hi to him. I think, Mr. Speaker, it is clearly an indication of what kind of a disastrous situation we have in this province in response to the leadership in federal and provincial relations. I think that has deteriorated dramatically, and I think we need to address that at some point. I criticize the Prime Minister for not meeting.

Ms. Janice Y. Lederman

Mr. Doug Martindale (Burrows): Mr. Speaker, it is with pleasure that I rise today to pay tribute to Ms. Jan Lederman, the former chair of the United Way of Winnipeg's board of trustees. She was presented with the André Mailhot Award at the United Way of Canada/Centraide Canada's national conference in Québec City on March 24, 2001. It is given to one individual annually, and this year Ms. Lederman was honoured with being the recipient of this award.

She was involved for eight years with the United Way of Winnipeg and spearheaded a community involvement initiative called Journey Forward which engaged people to look at social issues most important to them and to Winnipeggers and to find ways to work together to address these issues, which I might point out involved some 3000 people. This culminated in the Willing Community Forum in November 2000 which was considered a model across Canada and the United States. Ms. Lederman is a very deserving recipient of this award. She is also bright, articulate and personable as an individual. On behalf of all members, I would like to thank her for her volunteerism and her leadership with the United Way of Winnipeg.

* (14:30)

Thomas Report

Hon. Jon Gerrard (River Heights): Mr. Speaker, last week Paul Thomas tabled the report of the Review and Implementation Committee for the report of the Manitoba Pediatric Cardiac Surgery Inquest. Yesterday the Minister of Health (Mr. Chomiak) suggested in his comments that the Thomas report dealt only

with the period 1994 to 1995. A read of the report shows that Paul Thomas is dealing with the present situation when he says clearly: Where provincial leadership and involvement ends and the responsibility of the RHAs begins is not clear.

Again, Paul Thomas says: The exact nature of the working relationship between the two parties—he is referring to the minister and the regional health authorities—is not clear.

It is a real disappointment that the Minister of Health has not in 20 months been able to clarify the relationship between himself, as minister, and the regional health authorities. This relationship should have been made clear within the minister's first two months in office.

Ending the overlap and duplication is essential, as Paul Thomas indicates, in order to achieve cost savings and to clarify accountability. It is time for the Minister of Health to clarify the present overlap and blurred accountability. It is time for the Minister of Health to attend to what he should have attended to as one of his first tasks when he assumed office.

ORDERS OF THE DAY

House Business

Hon. Gord Mackintosh (Government House Leader): Mr. Speaker, before dealing with the routine for today, would you canvass the House and determine if there is consent to adjourn today at 5 p.m.?

Mr. Speaker: Is there agreement to adjourn at 5 p.m. today? [*Agreed*]

Mr. Mackintosh: Mr. Speaker, would you please call bills in the following order: First, second readings, Bills 27 and 30; second, debate on second readings, in this order, please, Bills 11, 19, 12, 14, 15 and 29; and then return to second readings, Bill 25, and we will take it from there.

SECOND READINGS

Bill 27—The Manitoba Hydro Amendment Act (2)

Hon. Greg Selinger (Minister charged with the administration of The Manitoba Hydro Act): Mr. Speaker, I move, seconded by the

Minister of Transportation and Government Services (Mr. Ashton), that Bill 27, The Manitoba Hydro Amendment Act (2); Loi no 2 modifiant la Loi sur l'Hydro-Manitoba, be now read a second time and referred to a committee of this House.

Motion presented.

Mr. Selinger: I am pleased to give second reading to this bill. As I mentioned in the first reading, this legislation will require Manitoba Hydro to charge customers connected to the provincial power grid the same rate for electricity service, regardless of where they live in Manitoba.

Mr. Speaker, on December 5, 2000, the Speech from the Throne promised this single rate for residential hydro users. The Lieutenant-Governor said at that time: A household in The Pas or in Lac du Bonnet will pay the same basic rate for hydro service as a household in Winnipeg. This bill delivers on that commitment.

Our Government sees this as an issue of fundamental fairness to all Manitobans with respect to an important service. Currently, Manitoba Hydro maintains three rate zones reflecting different cost structures associated with serving a large number of customers in a small area compared to serving a few customers spread across a large area. However, this difference in actual terms is less than 10 percent, so for example the average residential customer living in Zone 2 will save approximately \$2.70 a month on their electricity bill. These current Zone 2 customers are typically those living in small towns and medium density areas. The average customers living in what is currently called Zone 3 are typically farm families, low density areas. They will save \$10.11 per month.

Mr. Speaker, this legislation is long overdue. Many other provinces have uniform rates, including Québec, British Columbia and Nova Scotia. It is an issue of fundamental fairness. I am very pleased that we are able to work with our Crown utility to make uniform electricity rates a reality in Manitoba and **put everybody on an equal footing when it comes to the rates charged for basic service.**

Mr. Marcel Laurendeau (St. Norbert): I move, seconded by the honourable Member for Lakeside (Mr. Enns), that debate be adjourned.

Motion agreed to.

Bill 30—The Securities Amendment Act

Hon. Scott Smith (Minister of Consumer and Corporate Affairs): I move, seconded by the Minister of Transportation and Government Services (Mr. Ashton), that Bill 30, The Securities Amendment Act (Loi modifiant la Loi sur les valeurs mobilières), be now read a second time and referred to a committee of the House.

Motion presented.

* (14:40)

Mr. Smith: Mr. Speaker, the amendments to The Securities Act proposed in this bill fall into two broad categories. The first are amendments that will modernize and harmonize the securities legislation in the province.

You can break this into five generalizations, five categories: No. 1, making provisions to the Manitoba Securities Commission to participate in a national registration database which will allow registrants to operate in the securities industry to become registered in several jurisdictions from a single-entry point. This will present a benefit to both the registrants and investors, as the dealers will be able to service their clients with a minimum amount of paperwork and filing delays.

Number two, providing authority for the Securities Commission to officially recognize self-regulating organizations such as the Investment Dealers' Association and the mutual fund dealers' association, to which those registrants selling equities and mutual funds must belong. Recognition will give the Securities Commission both the ability to form a closer relationship with those groups but also a greater opportunity for scrutiny and oversight. This will be beneficial to not only investors but all Manitobans.

Number three, adopting the concept of the reporting issuer. As in other jurisdictions, this will result in additional financial reporting to the Manitoba Securities Commission by non-resident issuers currently not filing in the province. This in turn will provide greater disclosure to Manitoba investments.

Number four, harmonizing on a national basis to extend the notice period for takeover

COURT FILE NO.: 273/07
DATE: 20080516

ONTARIO
SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

KITELEY, CUMMING, AND SWINTON JJ.

B E T W E E N:

ADVOCACY CENTRE FOR TENANTS-
ONTARIO and INCOME SECURITY
ADVOCACY CENTRE on behalf of LOW-
INCOME ENERGY NETWORK

Appellant

- and -

ONTARIO ENERGY BOARD

Respondent

)
)
) *Paul Manning* and *Mary Truemner*, for
) the Appellant
)
)
)

) *Michael Millar*, for Ontario Energy Board
)

) *Fred Cass* and *David Stevens*, for
) Enbridge Gas Distribution Inc.
)

) *Robert Warren*, for Consumers Council of
) Canada
)

) **HEARD at Toronto:** February 25, 2008

KITELEY and CUMMING JJ.

The Appeal

[1] The Respondent Ontario Energy Board (the “Board”) is the provincial economic regulator for the natural gas and electricity sectors. The Board exercises its jurisdiction within the statutory authority established by the Legislature, being the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the “Act”).

[2] By a majority (2:1) decision dated April 26, 2007, the Board determined that the *Act* does not explicitly grant to the Board jurisdiction to order the implementation of a low income affordability program: *Enbridge Gas Distribution Inc.* (April 26, 2007), EB-2006-0034 (Ont. Energy Bd.) (the “Board Decision”). The Board also found that the Board does not gain the requisite jurisdiction through the doctrine of necessary implication.

[3] Enbridge Gas Distribution Inc. (“EGD”) sought approval by the Board of EGD’s 2007 gas distribution rates based simply upon the Board’s traditional, standard “cost of service” rate-making principles. The Appellant Low Income Energy Network (“LIEN”) had intervened in the application before the Board. LIEN argues that without a rate affordability program, the interests of low-income consumers are not protected. LIEN proposed that the Board accept as an issue in the EGD proceeding the following matter:

Should the residential rate schedules for EGD include a rate affordability assistance program for low-income consumers? If so, how should such a program be funded? How should eligibility criteria be determined? How should levels of assistance be determined?

[4] LIEN seeks from the Board the introduction of a rate affordability assistance program to make natural gas distribution rates affordable to poor people. The underlying premise of the proposal of LIEN is that low income consumers (estimated to be about 18% of households in Ontario) should pay less for gas distribution services than other consumers. LIEN emphasizes that the supply of natural gas (or other source of energy) serves to meet basic human needs such as warmth from heating and the generation of power. Those who cannot afford to use natural gas as a source of energy may be placed at a significant disadvantage. LIEN submits that the Board can consider ability to pay in setting rates if it is necessary to meet broad public policy concerns. Access to an essential service is arguably such a concern. The supply of natural gas can be considered a necessity that is available from a single source with prices set by the Board in the public interest.

[5] The majority of the Board held that the LIEN proposal amounted to an income redistribution scheme. The Board noted that such a scheme would require a consumer rate class based upon income characteristics and would implicitly require subsidization of this new class by other rate classes. It is undisputed that a common, if not universal, historical feature of rate-making for a natural monopoly is the application of the same charges to all consumers within a given consumer classification based upon cost of service, that is, cost causality.

[6] Section 33 of the *Act* provides for an appeal to this Court on a question of law or jurisdiction. LIEN seeks a declaration that the Board has the jurisdiction to order a “rate affordability assistance program” for low income consumers of the utility, EGD, within its franchise areas as the distributor of natural gas.

[7] The position of EGD, the Board and the intervenor, the Consumers Council of Canada, is that LIEN’s quite understandable and commendable concern is an issue of public policy to be dealt with by the Legislature and falls outside the jurisdiction of the Board.

The Standard of Review

[8] The issue is whether the Board is correct in its determination that it does not have jurisdiction to implement a low income affordability program.

[9] There is common ground that the standard of review is correctness. That is, this Court will interpret the statutory grant of authority on the basis of its own opinion as to a statute's construction, rather than deferring to the Board's determination of the issue. A tribunal's determination that it has no jurisdiction will be set aside as a "wrongful declining of jurisdiction" if the Court is of the view that the tribunal's decision is wrong. Donald J.M. Brown and John M. Evans, *Judicial Review of Administrative Action in Canada*, looseleaf (Toronto: Canvasback Publishing, 1998) at 14-3 to 14-4.

Analysis of the Board's Jurisdiction

A. *Applicable Principles*

[10] The Court is to be guided by the principles of statutory interpretation as set forth in Ruth Sullivan, *Driedger on the Construction of Statutes*, 3rd ed., (Toronto: Butterworths, 1994) at 131:

There is only one rule in modern interpretation, namely, courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the legislation, the consequences of proposed interpretations, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of (a) its plausibility, that is its compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just.

[11] The words of the *Act* are to be read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme and object of the legislation and the Legislature's intent. *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, [2006] 1 S.C.R. 140 at para. 37 [*Atco*].

[12] The statute shall be interpreted as being remedial and given such "fair, large and liberal interpretation as best ensures the attainment of its objects." *Legislation Act*, S.O. 2006, c. 21, Schedule F, s. 64 (1).

[13] A statutory administrative tribunal obtains its jurisdiction from two sources: explicit powers expressly granted by statute, and implicit powers by application of the common law doctrine of jurisdiction by necessary implication. *Atco, supra*, at para. 38.

[14] The Court must apply a “pragmatic or functional” analysis in determining the issue of jurisdiction, by considering the wording of the *Act* conferring jurisdiction upon the Board, the purpose of the *Act* creating the Board, the reason for the Board’s existence, the area of expertise of its members and the nature of the problem before the Board. *Union des employés de Service, local 298 v. Bibeault*, [1988] 2 S.C.R. 1048 at 1088.

B. The Wording of the Act

[15] Section 36 of the *Act* confers the Board’s jurisdiction:

36. (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

....

(2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

[16] LIEN submits that the Board’s authority to fix “just and reasonable rates” by adopting “any method or technique it considers appropriate”, conferred by s. 36 (2) and (3) of the *Act* is very broad and the statutory language must be given its ordinary meaning.

[17] The Board argues that the word “rates” is in the plural form in s. 36 (2) to allow the Board to set different rates for different classes of consumers based upon the costs of serving those consumers. For example, large industrial users are typically considerably more expensive to serve than residential consumers. Separate rate classes are a necessity to ensure that consumers reimburse for the actual costs of the service they receive.

[18] The majority opinion in the Board Decision is of the view that the words “any method or technique” cannot reasonably be interpreted to mean “a fundamental replacement of the rate making process based on cost causality with one based on income level as a rate grouping determinant.” (p.9)

[19] The phrase “approving or fixing just and reasonable rates” in the present s. 36 (2) was first introduced by s. 17 (1) of Bill 38, *An Act to Establish the Ontario Energy Board*, 1st Sess., 26th Leg., Ontario, 1960 by the then Minister of Energy Resources, the Hon. Robert Macaulay. He outlined for the Legislature the philosophy underlying rate setting (*Legislature of Ontario Debates*, 9 (8 February 1960) at 199 (Hon. Macaulay)):

First, why are there rate controls? There are rate controls because, in effect, the distribution of natural gas is a monopoly, a public utility. Secondly...it is fair that whatever rate is charged should be one designated, not only in the interests of the consumer, but also in the interests of the distributor...[O]ne really should have in mind 3 basic objectives: First, the rate should be low enough to secure to the user a fair and just rate. Second, the rate should be adequate to pay for good service and replacement and retirement of the used portion of the assets. Third, it should be high enough to attract a sufficient return on capital...

[20] He went on to explain the purpose of the Government's policy (at 205):

"[F]irst, to protect the consumer, and to see that he pays a fair and just rate, not more or less, and that is competitive with other fuels. Second, to make sure the rate is sufficient to provide adequate service, replacements and safety for the company providing the service. Third, it is that the company should be able to charge a rate which is sufficient to attract the necessary capital to expand.

[21] The present s.36 (3) replaced s.19 of the old *Ontario Energy Board Act*, R.S.O. 1980, c. 332, which required a traditional cost of service analysis in very prescriptive terms:

19 (2) In approving or fixing rates and other charges under subsection (1), the board shall determine a rate base for the transmitter, distributor or storage company, and shall determine whether the return on the rate base ...is reasonable.

The rate base ...shall be the total of,

- (a) a reasonable allowance for the cost of the property that is used or useful in serving the public, less an amount considered adequate by the Board for depreciation, amortization and depletion;
- (b) a reasonable allowance for working capital; and
- (c) such other amounts as, in the opinion of the Board, ought to be included.

[22] The authority was granted in s. 36 (3) to use "any method or technique it considers appropriate" in approving "just and reasonable rates" i.e., employing methods other than simply on a traditional cost of service basis as proscribed in the repealed s. 19 to set rates for the gas sector. This aligned the approach for natural gas with the non-prescriptive authority seen governing Ontario Hydro as a Crown corporation in rate setting for electricity distributors.

[23] Thus, under the former *Act* the phrase "just and reasonable rates" was limited to the cost of service basis articulated in prescriptive detail in s. 19. The change in repealing s. 19 and allowing the Board to "adopt any method or technique it considers appropriate" provides greater flexibility to the Board to employ other methods of rate making in approving and fixing "just and

reasonable rates” rather than simply the traditional cost of service regulation seen in the former s. 19.

[24] Subsection 36 (3) allows the Board to adopt “any method or technique that it considers appropriate” in fixing “just and reasonable rates.” The majority Board Decision view is that this provision, considered within the context of the *Act* as a whole, allows the Board to employ flexible techniques and methods for cost of service analyses in determining rates, for example, the incentive rate mechanisms currently used for the major gas utilities.

[25] In the same rate setting proceeding that is under review, EGD reportedly asked the Board to approve two fuel-switching programs to enable residential consumers to shift from electric-water heaters to gas-water heaters, given that the latter promote conservation inasmuch as there is greater energy efficiency. The programs are identical except that there is a subsidy offered for the low income group of \$800 per participant but a subsidy of only \$600 for other consumers. Vice Chair Kaiser in dissenting points out that none of the parties have objected to this proposal and no one has argued that the Board does not have jurisdiction to approve different subsidies based upon income levels.

[26] Indeed, the majority opinion in the Board Decision allows that the Board has ordered that specific funding be channeled aimed at low income consumers for “Demand Side Management Programs.”

[27] As well, the Board on occasion has reduced a significant rate increase because of so-called “rate shock” by spreading the increase over a number of years. Although this does not in itself suggest an unequal approach as between residential consumers it does indicate that the Board considers it has jurisdiction to take “ability to pay” into account in rate setting.

[28] EGD, like other utilities, makes annual contributions to enable emergency financial relief through the so-called “Winter Warmth Program” which provides funds as a subsidy to some low income consumers, enabling them to be able to heat their homes in winter months. These subsidies are taken into account as costs of the utility in the approval and fixing of rates by the Board. Although the program is funded by all consumers, to some extent there is indirect cross-subsidization within the residential consumer class.

[29] The Board points out that this is a relatively small program in the nature of a charitable objective, involving the United Way, which is specific to individual consumers in a financial crisis situation. But the fact remains that its implementation means that some residential consumers are paying less for the distribution and purchase of natural gas than other residential consumers are paying. If the Board has jurisdiction to approve utilities paying subsidies to the benefit of low income consumers then it arguably has jurisdiction to order utilities to provide special rates on a low income basis.

[30] Section 79 of the *Act* explicitly authorizes the Board to provide rate protection for rural or remote consumers of an electricity distributor. The majority decision argues that it is a reasonable inference that the Legislature, by virtue of the explicit singling out of a single

category of consumers in s. 79, did not intend this benefit to apply to other categories of consumers. The Board argues that if s. 36 (2) and (3) are intended to allow for differential rate setting for subsets of residential consumers, then s. 79 is unnecessary. The majority decision considers the existence of s. 79 as indicating that the Legislature has been explicit on issues that it considers warrant special treatment through a subsidy. The majority decision argues that the existence of s. 79 implicitly excludes any intent to confer jurisdiction to depart from simply the cost of service approach employed to implement the mandate given to the Board by s. 36.

[31] Moreover, the majority decision points out that rural rate assistance through s. 79 does not consider income level as an eligibility determinant. Rather, eligibility is based upon location and the inherent higher costs of service related to density levels. The assistance from the program is conferred upon all consumers within a given geographical area irrespective of their income level. Hence, this program arguably serves simply to mitigate the effect of the cost differential related to geography and remains consistent with a rate making process based upon cost causality. Nevertheless, “rate protection” through s. 79 operates as a subsidy paid by some of Ontario’s residential electricity consumers for the benefit of others and represents a departure from the principle of cost causality being applied on the same basis to all consumers within a given class (i.e., residential, commercial and industrial).

[32] As pointed out in the dissent by Board Vice Chair Gordon Kaiser, s. 79 was introduced in 1999 when the authority to regulate rates for *electricity* distributors was transferred to the Ontario Energy Board. Prior thereto, electricity distributors were regulated by Ontario Hydro, a Crown corporation which had established the policy of setting special rates in remote and rural areas through the now repealed s. 108 of the *Power Corporation Act*, R.S.O. 1990, c. P. 18. The inference can be made, as Vice Chair Kaiser asserts, that s. 79 was introduced into the *Act* to expressly indicate to the Board that this significant historical policy must continue.

C. *The Purpose of the Act and the Reason for the Board’s existence*

[33] The objectives for the Board with respect to natural gas regulation are set forth in s. 2 of the *Act*:

(2) The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:

1. To facilitate competition in the sale of gas to users.
2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
3. To facilitate rational expansion of transmission and distribution systems.
4. To facilitate rational development and safe operation of gas storage.
5. To promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers.

[34] The Board is charged under s. 2 of the *Act* with protecting “the interests of consumers with respect to prices” The Board argues that this provision speaks to consumers as a single class, not to a particular subset of consumers. The majority decision of the Board says the Board’s mandate is to balance the interests of consumers as a single group with the interests of the regulated utility in the setting of “just and reasonable rates.”

[35] The Divisional Court has emphasized in the past that the Board’s mandate to fix just and reasonable rates “is unconditioned by directed criteria and is broad; the board is expressly allowed to adopt any method it considers appropriate.” *Natural Resource Gas Ltd. v Ontario Energy Board*, [2005] O.J. No. 1520 at para. 13 (Div. Ct.). The Divisional Court also stated in *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2005), 75 O.R. (3d) 72, [2005] O.J. No. 756 at para.24:

...[T]he legislation involves economic regulation of energy resources, including setting prices for energy which are fair and reasonable to the distributors and the suppliers, while at the same time are a reasonable cost for the consumer to pay. This will frequently engage the balancing of competing interests, as well as consideration of broad public policy.

[36] Writing for the majority of the Supreme Court of Canada in *Atco, supra*, at para. 62 Bastarache J. stated that “[r]ate regulation serves several aims – sustainability, equity and efficiency – which underlie the reasoning as to how rates are fixed.”

D. The Area of Expertise of its Members and the Nature of the Problem before the Board

[37] The Board was asked to consider the application of the utility to establish rates. In that context, an intervenor asked the Board to consider whether, as a factor in rate-setting, the Board could consider the interests of low-income consumers and establish a rate affordability program. That issue of rate-setting is squarely within the jurisdiction of the Board.

[38] The majority opinion in the Board Decision correctly states that the Board’s mandate for economic regulation is “rooted in the achievement of economic efficiencies, the establishment of fair returns for natural monopolies and the development of appropriate costs allocation methodologies”. However, that does not answer the question as to the full scope of the Board’s jurisdiction in approving or fixing “just and reasonable rates” and adopting “any method or technique that it considers appropriate” in so doing.

[39] The Board’s regulatory power is designed to act as a proxy in the public interest for competition in view of a natural gas utility’s geographical natural monopoly. Absent the intervention of the Board as a regulator in rate-setting, gas utilities (for the benefit of their

shareholders) would be in a position to extract monopolistic rents from consumers, in particular, given a relatively inelastic demand curve for their commodity. Clearly, a prime purpose of the *Act* and the Board is to balance the interests of consumers of natural gas with those of the natural gas suppliers. The Board's mandate through economic regulation is directed primarily at avoiding the potential problem of excessive prices resulting because of a monopoly distributor of an essential service.

[40] In performing this regulatory function, it is consistent for the Board to seek to protect the interests of *all* consumers vis-a-vis the reality of a monopoly. The Board must balance the respective interests of the utility and the collective interest of all consumers in rate setting. *Re Union Gas Ltd. and Ontario Energy Board et al.* (1983), 1 D.L.R. (4th) 698 (Div. Ct.), (1983) 43 O.R. (2d) 489 at 501. The Board's regulatory power is primarily a proxy for competition rather than an instrument of social policy. *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, (2006), 268 D.L.R. (4th) 408 at para. 33 [*Dalhousie*].

[41] *Dalhousie* dealt with a request for a low income affordability program like that advanced by LIEN. However, it involved a consideration of rate setting under s. 67 (1) of the Nova Scotia *Public Utilities Act*, R.S.N.S. 1989, c. 380, which is very different in wording with respect to jurisdiction to that seen in s. 36 of the *Act* at hand. The Nova Scotia provision expressly provides that "rates shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate" Hence, the Nova Scotia Utility and Review Board found that it did not have jurisdiction to order low income affordability programs.

[42] Section 36 of the *Act* has broad language, empowering the Board to set "just and reasonable" rates for the distribution of natural gas. The supply of natural gas can be considered a necessity that is available from a single source with prices set by the Board in the public interest. The Board has traditionally set rates on a "cost of service" basis, that is, on the basis of cost causality and employing a complex cost allocation exercise. In brief, this approach first looks to the utility's capital investments and maintenance costs including a fair rate of return to determine revenues required. The revenue requirement is then divided amongst the utility's rate paying consumers on a rate class basis (i.e., residential, commercial, industrial, etc.).

[43] The rates have been traditionally designed with the principled objective of having each rate class pay for the actual costs that class imposes upon the utility. That is, the Board has sought to avoid inter-class and intra class subsidies. See RP-2003-0063 (2005) at 5. Consistent with this approach, the Board has refused the establishment of a special rate class to provide redress for aboriginal consumers. *Decision with Reasons EBRO493* (1997) (O.E.B.). In that case, the Ontario Native Alliance ("ONA") requested the Board to order a utility to evaluate the establishment of a rate class for the purpose of providing a special rate class for aboriginal peoples. At 316-17, the Board stated:

The Board is required by the legislation to "fix just and reasonable rates", and in doing so it attempts to ensure that no undue discrimination occurs between rate classes, and that

the principles of cost causality are followed in allocating the underlying rates. While the board recognizes ONA's concerns, the Board finds that the establishment of a special rate class to provide redress for aboriginal consumers of Centra does not meet the above criteria and it is not prepared to order the studies requested by ONA.

[44] This decision would be within the Board's jurisdiction and a like response to LIEN in the case at hand would arguably be consistent and reasonable. However, the Board in dealing with the ONA request did not decline on the basis of jurisdiction. Rather, it said that it should not exercise its jurisdiction as requested by ONA for the reasons given.

[45] A low income rate affordability program would necessarily lead to treating consumer groups on a differentiated basis with higher prices for a majority of residential consumers and subsidization of the low-income subset by the majority group and/or other classes of consumers.

[46] If the Board were to reduce the rates for one class of consumers based upon an income determinant, the Board would have to increase the rates for another class or classes of consumers. In effect, such a rate reduction would impose a regressive indirect tax upon those required to pick up the shortfall. Such an approach would arguably be a dramatic departure from the Board's regulatory function as implemented to date, which has been to protect the collective interest of consumers dealing with a monopoly supplier through a "cost of service" calculation and then to treat consumers equally through determining rates to pay for the "cost of service" on a cost causality basis for classes of consumers.

[47] The Board's mandate has not been directed to the public interest in social or distributive justice through a differentiation of rates on the basis of income. That need is seen to be met through other mechanisms and programs legislated by the provincial Legislature and/or Parliament, for example, by refundable tax credits and social assistance.

[48] Indeed, the provincial income tax legislation previously provided for public tax expenditures to assist low income consumers with rising electricity costs. This was done through an "Ontario home electricity payment" by reference to income levels. *Income Tax Act*, R.S.O. 1990, c.1.2, s. 8.6.1, as rep. by *Income Tax Amendment Act (Ontario Home Electricity Relief)*, 2006, S.O. 2006, c. 18, s. 1. As well, Parliament has provided a one-time relief for energy costs to low income families and seniors in Canada through the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

[49] The Board is an economic regulator, rather than a formulator of social policy. While no doubt the Board must take into account broad policy considerations, rate-setting is at the core of the Board's jurisdiction. *Garland v. Consumers' Gas Company* (2000), 185 D.L.R. (4th) 536 at paras. 17, 45-46 (Ont. S.C.J.). Special rates for low income consumers would not be based upon economic principles of regulation but rather on the social principle of ability to pay. Any program to subsidize low income consumers would require a source of funding which is a matter of public policy. See generally *Re Rate Concessions to Poor Persons and Senior Citizens*, 14 Pub. Util. Rep. 4th 87 at 94 (Or. 1976).

[50] This view of the nature and limit of the regulatory function is generally accepted as the norm in other jurisdictions. See for example *Washington Gas light Co. v. Public Service Commission of the District of Columbia* (1982), 450 A.2d 1187 at para. 38 (D.C. Ct. App.); *State of Louisiana v. the Council of the City of New Orleans and New Orleans Public Service, Inc.* (1975), 309 So. 2nd 290 at 294 (La. Sup. Ct.).

[51] The historical common law approach for public utility regulation has been that consumers with similar cost profiles are to be treated equally so far as reasonably possible with respect to the rates paid for services. See, for example, *St. Lawrence Rendering Co. Ltd. v. The City of Cornwall*, [1951] O.R. 669-685 at 683; *Chastain et al. v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 at 454 (B.C.S.C); *Canada (Attorney General) v. Toronto (City)* (1893), 23 S.C.R. 514 at 519-520.

Conclusions on the Board's Jurisdiction

[52] We agree that the traditional approach of “cost of service” is the root principle underlying the determination of rates by the Board because that is necessary to meet the fundamental, core objective of balancing the interests of all consumers and the natural monopoly utility in rate/price setting.

[53] However, the Board is authorized to employ “any method or technique that it considers appropriate” to fix “just and reasonable rates.” Although “cost of service” is necessarily an underlying fundamental factor and starting point to determining rates, the Board must determine what are “just and reasonable rates” within the context of the objectives set forth in s. 2 of the *Act*. Objective #2 therein speaks to protecting “the interests of consumers with respect to prices.”

[54] The “cost of service” determination will establish a benchmark global amount of revenues resulting from an estimated quantity of units of natural gas or electricity distributed. The Board could use this determination to fix rates on a cost causality basis. This has been the traditional approach.

[55] However, in our view, the Board need not stop there. Rather, the Board in the consideration of its statutory objectives might consider it appropriate to use a specific “method or technique” in the implementation of its basic “cost of service” calculation to arrive at a final fixing of rates that are considered “just and reasonable rates.” This could mean, for example, to further the objective of “energy conservation”, the use of incentive rates or differential pricing dependent upon the quantity of energy consumed. As well, to further the objective of protecting “the interests of consumers” this could mean taking into account income levels in pricing to achieve the delivery of affordable energy to low income consumers on the basis that this meets the objective of protecting “the interests of consumers with respect to prices.”

[56] The Board is engaged in rate-setting within the context of the interpretation of its statute in a fair, large and liberal manner. It is not engaged in setting social policy.

[57] This is not, of course, to imply any preferred course of action in rate setting by the Board. The Board in its discretion may determine that “just and reasonable rates” are those that follow from the approach of “cost causality” once the “cost of service” amount is determined. That is, the principle of equality of rates for consumers within a given class (e.g., residential consumers) may be viewed as the most just and reasonable approach. A determination by the Board that all residential gas consumers (with relatively minor deviations through such programs as the “Winter Warmth Program”) pay the same distribution rates is not in itself discriminatory on a prohibited ground. Indeed, it can be seen as a non-discriminatory policy in terms of prices paid.

[58] Nor is it to suggest that as a matter of public policy, objectives of distributive justice or conservation in respect of energy consumption are best achieved by rate setting as compared to, for instance, tax expenditures or social assistance devised and implemented by the Legislature through mechanisms independent of the operation of the *Act*. It is noted that the Minister is given the authority in s. 27 of the *Act* to issue policy statements as to matters that the Board must pursue; however, the Minister has not issued any policy statement directing the board to base rates on considerations of the ability to pay. Moreover, the power granted to a regulatory authority “must be exercised reasonably and according to the law, and cannot be exercised for a collateral object or an extraneous and irrelevant purpose, however commendable.” *Re Multi Malls Inc. et al. and Minister of Transportation and Communications et al* (1977), 14 O.R. (2d) 49 at 55 (C.A.). As we have said, cost of service is the starting point building block in rate setting, to meet the fundamental concern of balancing the interests of all consumers with the interests of the natural monopoly utility.

[59] Nor does our conclusion presume as to what methods or techniques may be available in determining “just and reasonable rates.” Efficiency and equity considerations must be made. Rather, this is to say only that so long as the global amount of return to the utility based upon a “cost of service” analysis is achievable, then the rates/prices (and the methods and techniques to determine those rates/prices) to generate that global amount is a matter for the Board’s discretion in its ultimate goal and responsibility of approving and fixing “just and reasonable rates.”

[60] The issue before the Court is that of jurisdiction, not how and the manner by which the Board should exercise the jurisdiction conferred upon it.

[61] In our view, and we so find, the Board has the jurisdiction to take into account the ability to pay in setting rates. We so find having taken into account the expansive wording of s. 36 (2) and (3) of the statute and giving that wording its ordinary meaning, having considered the purpose of the legislation within the context of the statutory objectives for the Board seen in s. 2, and being mindful of the history of rate setting to date in giving efficacy to the promotion of the legislative purpose.

[62] We also find that that interpretation is appropriate taking into account the criteria articulated in *Driedger*, above, namely it complies with the legislative text, it promotes the legislative purpose and the outcome is reasonable and just.

[63] As indicated above, a statutory administrative tribunal obtains its jurisdiction from explicit powers or implicit powers. Having found that the jurisdiction to consider ability to pay in rate setting is explicitly within the *Act*, we need not consider the doctrine of necessary implication or the related principle of implied exclusion.

The issue of the *Canadian Charter of Rights and Freedoms*

[64] Before concluding, it is appropriate to mention the submission made on behalf of LIEN in respect of s. 15 (1) of the *Canadian Charter of Rights and Freedoms*, Part 1 of the *Constitution Act, 1982*, being Schedule B to the *Canada Act, 1982* (U.K.), c. 11 (the “*Charter*”).

[65] LIEN says it raises the *Charter* simply within the context of it being an interpretive tool in discerning the meaning of an asserted ambiguous s. 36 of the *Act*. LIEN says it does not raise any issue that the *Act* or the Board’s actions or inactions are contrary to the *Charter*.

[66] LIEN argues that in the absence of clear statutory provisions, the requirement for “just and reasonable rates” must be interpreted to comply with s. 15. The *Charter* applies to provincial legislation and can be used as an interpretive tool. *R. v. Rogers*, [2006] 1 S.C.R. 554, [2006] S.C.J. No. 15 at para. 18. In our view, as stated above, the *Act* provides the Board with the requisite jurisdiction without having to look to the *Charter*.

[67] While we heard submissions from LIEN, we declined to hear from counsel for the respondents on this issue. We agree with our colleague Swinton J. that such an argument requires a full evidentiary record.

Disposition

[68] For the reasons given, the appeal is allowed and it is declared that the Board has the jurisdiction to establish a rate affordability assistance program for low income consumers purchasing the distribution of natural gas from the utility, EGD.

[69] All parties agree that there is not to be any award of costs in respect of this appeal.

KITELEY J.

CUMMING J.

Released: May , 2008

Swinton J. (dissenting):

[70] The sole issue in this appeal is whether the Ontario Energy Board (the “Board”) erred in holding that it had no jurisdiction, when setting residential rates for gas distribution, to order a rate affordability program for low income consumers. In my view, the majority of the Board was correct in concluding that the Board lacked jurisdiction to make such an order.

[71] The majority of the Board predicated its decision on the understanding that the appellants’ proposal contemplated the establishment of a rate group for low income residential consumers that would be funded by general rates. I, too, proceed on that assumption. While there were no details of a specific program put forth by the appellants during the hearing, it is inevitable that the Board, in setting lower rates for the economically disadvantaged, would have to impose higher rates on other consumers.

The Board’s Practice in Setting Rates

[72] Pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the “Act”), the Board has authority to set rates for both gas and electricity. It has traditionally set rates for gas through a “cost of service” assessment, in which it seeks to determine a utility’s total cost of providing service to its customers over a one year period (the “test year”). According to the Board’s factum, these costs include the rate base (which is essentially the net book value of the utility’s total capital investments) and the utility’s operational and maintenance costs for the test year, among other things. The utility’s total costs for the test year (usually including a rate of return on the rate base portion) forms the revenue requirement. The revenue requirement is then divided amongst the utility’s ratepayers on a rate class basis (that is, residential, small commercial, industrial, etc.).

[73] With respect to gas, it has always been the Board’s practice to allocate the revenue requirement to the different rate classes on the basis of how much of that cost the rate class actually causes (“cost causality”). To the greatest extent possible, the Board has striven to avoid inter-class subsidies (see, for example, Decision with Reasons, RP-2003-0063 (2005), p. 5).

The Proper Approach to Statutory Interpretation

[74] To determine the issue in this appeal, it is necessary to consider the powers conferred on the Board by its constituent legislation, the *Ontario Energy Board Act*. That Act must be interpreted using the modern principles of statutory interpretation described by Professor Ruth Sullivan in *Driedger on the Construction of Statutes* (3rd ed.) (Toronto: Butterworths, 1994) as follows:

There is only one rule in modern interpretation, namely, courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the

legislation, the consequences of proposed interpretations, the presumptions of special rules of interpretation, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of (a) its plausibility, that is, its compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just. (at p. 131)

[75] The words of a statute are to be read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme of the Act, its objects, and the intent of the Legislature (*ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, [2006] 1 S.C.R. 140 at para. 37).

The Words of the Provision in Issue

[76] Subsection 36(2) of the Act gives the Board the broad authority to approve or fix “just and reasonable” rates for the distribution of gas. On its face, those words might encompass the power to set rates according to income. However, the words do not explicitly confer the power to do so, and the Supreme Court of Canada commented in *ATCO*, *supra* that a discretionary grant of authority to a tribunal cannot be viewed as conferring unlimited discretion. A regulatory tribunal must interpret its powers “within the confines of the statutory regime and principles generally applicable to regulatory matters, for which the legislature is assumed to have had regard in passing that legislation” (at para. 50).

[77] The appellants also rely on s. 36(3), which states that in approving or fixing just and reasonable rates, the Board may adopt “any method or technique that it considers appropriate”. These words were added to the Act in 1998. Examples of methods or techniques used by the Board for setting gas distribution rates are cost of service regulation and incentive regulation.

[78] On its face, the words of s. 36(3) do not confer the jurisdiction to provide special rates for low income customers. The subsection replaced an earlier provision of the Act which required a traditional cost of service analysis in setting rates. I agree with the conclusion of the Board majority as to the meaning of s. 36(3) (Reasons, p. 10):

It gives the Board the flexibility to employ other methods of ratemaking in fixing just and reasonable rates, such as incentive ratemaking, rather than the traditional costs of service regulation specified in section 19 of the old Act. The change in the legislation was coincident with the addition of the regulation of the electricity sector to the Board’s mandate. The granting of the authority to use methods other than cost of service to set rates for the gas sector was an alignment with the non-prescriptive authority to set rates for the electricity sector. The Board is of the view that if the intent of the legislature by the new language was to include ratemaking considering income level as a rate class determinant, the new Act would have made this provision explicit given the opportunity

at the time of the update of the Act and the resultant departure from the Board's past practice.

The Regulatory Context

[79] According to longstanding principles governing public utilities developed under the common law, a public utility like the respondent Enbridge Gas Distribution Inc. ("Enbridge") must treat all its customers equally with respect to the rates they pay for a particular service (*Attorney General of Canada v. The Corporation of the City of Toronto* (1892), 23 S.C.R. 514 at 519-20; *St. Lawrence Rendering Co. Ltd. v. Cornwall*, [1951] O.R. 669 (H.C.J.) at 683; *Chastain v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 (B.C.S.C.) at 454).

[80] As noted in the Board's majority reasons, the Board is, at its core, an economic regulator (Reasons, p. 4). Rate setting is at the core of its jurisdiction (*Garland v. Consumer's Gas Company* (2000), 185 D.L.R. (4th) 536 (Ont. S.C.J.) at para. 45). I agree with the majority's description of economic regulation as being "rooted in the achievement of economic efficiencies, the establishment of fair returns for natural monopolies and the development of appropriate cost allocation methodologies" (Reasons, p. 4).

[81] Historically, in setting rates, the Board has engaged in a balancing of the interests of the regulated utility and consumers. The Board has not historically balanced the interests of different groups of consumers. As the Divisional Court stated in *Union Gas Ltd. v. Ontario (Energy Board)* (1983), 43 O.R. (2d) 489 at p. 11 (Quicklaw):

... it is the function of the O.E.B. to balance the interest of the appellant in earning the highest possible return on the operation of its enterprise (a monopoly) with the conflicting interest of its customers to be served as cheaply as possible.

See, as well, *Northwestern Utilities v. The City of Edmonton*, [1929] 1 S.C.R. 186 at 192.

[82] In a similar vein, the Supreme Court in *ATCO, supra* spoke of a "regulatory compact" which ensures that all customers have access to a utility at a fair price. The Court went on to state (at para. 63):

Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specified area at rates that will provide companies the opportunity to earn a fair rate of return for all their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers of their defined territories, and are required to have their rates and certain operations regulated...

The Court described the object of the Act "to protect both the customer *and* the investor" (at para. 64).

[83] The Legislature, in conferring power on the Board, must be taken to have had regard to the principles generally applicable to rate regulation (*ATCO, supra* at paras. 50 and 64). I agree with the submission of Enbridge that those principles are the following:

- (a) customers of a public utility must be treated equally insofar as the rate for a particular service or class of services is concerned; and
- (b) the Legislature will be presumed not to have intended to authorize discrimination among customers of a public utility unless it has used specific words to express this intention.

[84] Thus, the considerations of justice and reasonableness in the setting of rates have been and are those between the utility and consumers as a group, not among different groups of consumers based on their ability to pay.

Other Provisions of the Act

[85] In applying s. 36(2), the Board must be bound by the objectives set out in s. 2 of the Act, which includes

- 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

[86] The appellants submit that these words are broad enough to permit the Board to order a rate affordability assistance program. However, that is not obvious from the words used, which refer to “consumers” as a whole, and not to any particular subset of consumers. Indeed, it can be argued that any low income rate affordability program would run counter to the stated objective, given that such a program must almost certainly be funded through higher rates paid by other consumers. The result would be to provide benefits to one group of consumers at the expense of others.

[87] The reason for this conclusion lies in the Board’s historical approach to rate setting, as described earlier in these reasons. The Board sets a revenue requirement for utilities before allocating those costs to the different rate classes. The only way the utility could recover its revenue requirement, given a rate class with lower rates for low income consumers, would be to increase the rates charged to other classes. Therefore, such higher prices can not be seen as protecting the interests of consumers with respect to prices, as set out in objective 2.

[88] Moreover, the Act contains an explicit provision in s. 79 that allows the Board to provide rate protection for rural and remote customers of electricity distributors. Subsection 79(1) provides:

The Board, in approving just and reasonable rates for a distributor who delivers electricity to rural or remote consumers, shall provide rate protection for those consumers

or prescribed classes of those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Section 79 also provides grandfathering for those who had a subsidy prior to the change in the Act. As well, it explicitly allows the distributor to be compensated for the subsidized rates through contributions from other consumers, as provided by the regulations.

[89] This section was added to the Act in 1998, when the Board was given the authority over electricity rate regulation. Section 79 ensured the ongoing protection of rural rates put in place when electricity distribution was regulated by Ontario Hydro.

[90] One of the principles of statutory interpretation is “implied exclusion”. As Professor Sullivan has stated, this principle operates “whenever there is reason to believe that if the legislature had meant to include a particular thing within its legislation, it would have referred to that thing expressly” (*supra*, p. 186). While the purpose of s. 79 of the Act was to protect a pre-existing policy to assist rural and remote residential consumers, nevertheless, it is telling that there is no similar explicit power to order special rates or rate subsidies for other groups elsewhere in the Act.

The Significance of Ordering Rate Affordability Programs

[91] An appropriate interpretation can be justified in terms of its promotion of the legislative purpose and the reasonableness of the outcome (see Sullivan, quoted above at para. 5).

[92] The ability to order a rate affordability program would significantly change the role that the Board has played – indeed, the majority of the Board stated a number of times that the proposal to base rates on income level would be a “fundamental” departure from its current practice. In the past, the Board has acted as an economic regulator, balancing the interests of the utility and its shareholders against the interests of consumers as a group. Were it to assume jurisdiction over rate affordability programs, it would carry out an entirely different function. It would enter into the realm of social policy, weighing the interests of low income consumers against those of other consumers. This is not a role that the Board has traditionally played. This is not where its expertise lies, nor is it well-suited to taking on such a role.

[93] An examination of the particular case before the Board illustrates this. The appellants seek a rate affordability assistance program for gas in response to Enbridge’s application for a rate increase for gas distribution – that is, for the *delivery* of natural gas. Customers can make arrangements for the purchase of the commodity of natural gas with a variety of suppliers in the competitive market. Therefore, were the Board to assume jurisdiction to order a rate affordability assistance program here, it could address only one part of the problem that low income consumers face in meeting their heating costs – the cost of distribution of gas.

[94] In addition, the Board would have to consider eligibility criteria for a rate affordability assistance program that reasonably would take into account existing programs for assistance to

low income consumers. Obviously, this would include social assistance programs. As well, Enbridge, in its factum, has identified other programs which provide assistance for low income consumers. For example, the Ontario government has implemented a program to assist low income customers with rising electricity costs through amendments to income tax legislation (*Income Tax Act*, R.S.O. 1990, c. I.2, s. 8.6.1, as amended S.O. 2006, c.18, c.1). At the federal level, there was one-time relief for low income families and senior citizens provided by the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

[95] Moreover, in order to cover the lower costs, the Board would have to increase the rates of other customers in a manner that would inevitably be regressive in nature, as it is difficult to conceive how the Board would be able to determine, in a systematic way, the ability of these other customers to pay.

[96] Clearly, the determination of the need for a subsidy for low income consumers is better made by the Legislature. That body has the ability to consider the full range of existing programs, as well as a wide range of funding options, while the Board is necessarily limited to allocating the cost to other consumers. The relative advantages of a legislative body in establishing social programs of the kind proposed are well described in the following excerpt from a decision of the Oregon Public Utility Commissioner (*Re Rate Concessions to Poor Persons and Senior Citizens* (1976), 14 PUR 4th 87 at p. 94):

Utility bills are not poor persons' only problems. They also cannot afford adequate shelter, transportation, clothing or food. The legislative assembly is the only agency which can provide comprehensive assistance, and can fund such assistance from the general tax funds. It has the information and responsibility to deal with such matters, and can do so from an overall perspective. It can determine the needs of various groups and compare those needs to existing social programs. If it determines a special program is needed to deal with energy costs, it can affect all energy sources rather than only those the commissioner regulates.

With clear authority to establish social welfare policy, the legislative assembly also can monitor all state and federal welfare programs and the sources and extent of aid given to different groups. Without such overview, as independent agencies aid various segments of society, the total aid given each group is unknown, and unequal treatment of different groups becomes likely.

[97] Where the issue of rate affordability programs has arisen in other jurisdictions, courts and boards have ruled that a public utilities board does not have jurisdiction to set rates based on ability to pay (see, for example, *Washington Gas Light Co. v. Public Service Commission of the District of Columbia* (1982), 450 A. 2d 1187 (D.C. Ct. App.) at para. 38; *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* (2006), 268 D.L.R. (4th) 408 (N.S.C.A.) at 419; Alberta Energy and Utilities Board Decision 2004-066, Section 9.2.6 at 161, as well as the Oregon case, *supra*).

[98] The appellants distinguish the *Dalhousie Legal Aid* case because the Nova Scotia legislation is different from Ontario's. Specifically, s. 67(1) of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 provides that "[a]ll tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate".

[99] While the language of the two statutes does differ, nevertheless, the reasons of the Nova Scotia Court of Appeal make it clear that the Board's role is not to set social policy. At para. 33, Fichaud J.A, observed, "The Board's regulatory power is a proxy for competition, not an instrument of social policy."

[100] Moreover, the principle in s. 67(1) of the Nova Scotia Act requiring that rates be charged equally is a codification of the common law, set out earlier in these reasons. The Ontario Board has long operated according to the same principles.

[101] The appellants submit that the recent decision in *Allstream Corp. v. Bell Canada*, [2005] F.C.J. No. 1237 (C.A.) assists their case. There, the Federal Court of Appeal upheld a decision of the Canadian Radio-Television and Telecommunications Commission (the "CRTC") approving special facilities tariffs submitted by Bell for the provision of optical fibre services pursuant to certain customer-specific arrangements. All but one related to a Quebec government initiative aimed at supporting the construction of broadband networks for rural municipalities, school boards and other institutions. The Court determined that the Commission's decision approving the tariffs was not patently unreasonable, given the exceptional circumstances of the case that justified a deviation from the normal practice of rate determination. The Court noted that the Commission considered matters that were not purely economic, but noted that such considerations were part of the Commission's wide mandate under s. 7 of the *Telecommunications Act*, S.C. 1993, c. 38 (at paras. 34-35).

[102] Section 7 of that Act, unlike s. 2 of the *Ontario Energy Board Act*, expressly includes the power "to respond to the economic and social requirements of users of telecommunications services" (s. 7(h)), as well as to enrich and strengthen the social and economic fabric of Canada and its regions (s. 7(a)). Moreover, while s. 27(2)(b) of that Act forbids unjust discrimination in rates charged, s. 27(6) explicitly permits reduced rates, with the approval of the Commission, for any charitable organization or disadvantaged person.

[103] In contrast to the broad mandate given to the CRTC, the objectives of the Board are much more confined. When the Board's objectives go beyond the economic realm, specific reference has been made to other objectives, such as conservation and consumer education (s. 2 (5) and (6)). There is no reference to the consideration of economic and social requirements of consumers.

[104] The appellants have also pointed out that the Board has in the past authorized programs that transfer benefits to lower income customers. The Winter Warmth program is one in which individuals can apply for emergency financial relief with heating bills. It is triggered by an

application from a particular customer, and the program is funded by all customers. The fact that the Board has approved this charitable program does not lead to the conclusion that it has jurisdiction to set rates on the basis of income level.

[105] With respect to the Demand Side Management (DSM) programs, the majority of the Board explained that this is not equivalent to a rate class based on income level. At p. 11 of its Reasons, the majority stated,

The Board is vigilant in ensuring that customer groups are afforded the opportunity to receive the benefits of the costs charged. In the case of Demand Side Management (DSM) programs, for example, the Board has ordered that specific funding be channeled for programs aimed at low income customers. It cannot be argued that this constitutes discriminatory pricing. Rather, the contrary. It is an attempt to avoid discrimination against low income customers who also pay for DSM programs but may not have equal opportunities to take advantage of these programs.

[106] Were the Board to assume jurisdiction to order a rate affordability assistance program, it would be taking on a significant new role as a regulator of social policy. Given the dramatic change in the role that it has historically played, as well as the departure from common law principles, it would require express language from the Legislature to confer such jurisdiction

Jurisdiction by Necessary Implication

[107] In order to impute jurisdiction to a regulatory body, there must be evidence that the exercise of the power in question is a practical necessity for the regulatory body to accomplish the goals prescribed by the Legislature (*ATCO, supra* at paras. 51, 77). In this case, there is no evidence that the power to implement a rate affordability assistance program is a practical necessity for the Board to meet its objectives as set out in s. 2.

The Role of the Charter

[108] The appellants submit that the values found in s. 15 of the *Canadian Charter of Rights and Freedoms* should be considered in the interpretation of the ratemaking provisions of the Act. However, the Charter has no relevance in interpretation unless there is genuine ambiguity in the statutory provision (*R. v. Rodgers*, [2006] 1 S.C.R. 554 at paras. 18-19). A genuine ambiguity is one in which there are “two or more plausible readings, each equally in accordance with the intentions of the statute” (at para. 18).

[109] In my view, there is no ambiguity in the interpretation of s. 36 of the Act, and therefore, there is no need to resort to the Charter.

[110] In any event, the appellants’ argument is, in fact, that the failure of the Board to order a rate affordability program is discriminatory on the basis of sex, race, age, disability and social assistance, because of the adverse impact on these groups (*Factum*, para. 43, as well as para. 47).

Such an argument can not be made without a full evidentiary record, and the inclusion of statistical material in the Appeal Book is not a sufficient basis on which to address this equality argument.

Conclusion

[111] For these reasons, I am of the view that the majority decision of the Board was correct, and that the Board has no jurisdiction to order rate affordability assistance programs for low income consumers. Therefore, I would dismiss the appeal.

Swinton J.

Released: May 16, 2008

COURT FILE NO.: 273/07

DATE: 20080516

**ONTARIO
SUPERIOR COURT OF JUSTICE**

DIVISIONAL COURT

KITELEY, CUMMING AND SWINTON JJ.

B E T W E E N:

ADVOCACY CENTRE FOR TENANTS-
ONTARIO and INCOME SECURITY
ADVOCACY CENTRE on behalf of LOW-
INCOME ENERGY NETWORK

Appellant

- and -

ONTARIO ENERGY BOARD

Respondent

REASONS FOR JUDGMENT

Released: May 16, 2008

2006 NSCA 74
Nova Scotia Court of Appeal

Dalhousie Legal Aid Service v. Nova Scotia Power Inc.

2006 CarswellNS 249, 2006 NSCA 74, [2006] N.S.J. No. 243, 149 A.C.W.S.
(3d) 355, 245 N.S.R. (2d) 206, 268 D.L.R. (4th) 408, 777 A.P.R. 206

Dalhousie Legal Aid Service (Appellant) v. Nova Scotia Power Inc. (Respondent)

Fichaud J.A., Freeman J.A., and Saunders J.A.

Heard: May 29, 2006

Judgment: June 20, 2006

Docket: C.A. 248695

Counsel: Claire McNeil, Vincent Calderhead for Appellant
Daniel Campbell, Q.C. for Respondent
Richard Melanson for Nova Scotia Utility & Review Board
Stephen McGrath for Attorney General of Nova Scotia

Subject: Public; Civil Practice and Procedure

Headnote

Public law --- Public utilities — Regulatory boards — Practice and procedure — Judicial review — Jurisdiction of board
Power corporation served nearly half million customers in province — Corporation applied to board to institute rate
increases — Intervenor requested board approve program featuring power rate credits for low income customers —
Board concluded that it had no power to consider intervenor's proposal and declined to consider plan — Intervenor
brought appeal from board's decision — Appeal dismissed — Board did not err in refusing to consider merits of plan —
Board's regulatory power was proxy for competition, not instrument of social policy — Legislation mandated that rates
were always to be charged equally to all persons in substantially similar circumstances and conditions — Board could
not reduce rates to low income customers who received same service as high income customers — Previous decisions
where board approved load retention rates for large industrial customers were not relevant to current proceedings —
Such decisions dealt with distinct economic realities of demand and competition which were legitimately within board's
purview.

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Generally — considered

s. 2(f) "service" (iii) — considered

s. 42 — referred to

s. 44 — considered

s. 52 — considered

s. 63(1) — referred to

s. 64(1) — considered

s. 67(1) — considered

s. 73(3) — considered

s. 86 — considered

s. 107 — considered

Telecommunications Act, S.C. 1993, c. 38

s. 7 — referred to

s. 47(a) — considered

Utility and Review Board Act, S.N.S. 1992, c. 11

Generally — referred to

s. 26 — considered

s. 30(1) — considered

APPEAL by intervenor from board's decision to decline to consider proposal.

Fichaud J.A.:

1 Nova Scotia Power applied to the Utility and Review Board for a rate increase. Dalhousie Legal Aid intervened and requested that the Board approve a program featuring power rate credits for low income customers. The Board declined. The Board was of the view that the legislation did not authorize the Board to reduce power rates based on the income level of the customer. Dalhousie Legal Aid appeals. The issue is whether the Board committed reviewable error by concluding that it had no statutory authority to adopt a rate assistance program for low income customers.

Background

2 Nova Scotia Power Incorporated ("NSP") produces and supplies electrical energy. As of December 31, 2003, NSP served approximately 460,000 customers throughout Nova Scotia. NSP is the successor to the Nova Scotia Power Corporation, a Crown corporation that was privatized in 1992. In January 1999, NSP became the principal subsidiary of what is now Emera Incorporated.

3 NSP is a public utility regulated under the *Public Utilities Act* RSNS 1989, c. 380, as amended. Section 64(1) reads:

64 (1) No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.

The "Board" is the Nova Scotia Utility and Review Board, created by the *Utility and Review Board Act* SNS 1992, c. 11, as amended ("*URB Act*").

4 In May 2004 NSP filed with the Board an application for approval of increased rates, followed by a revised application in June 2004. The application would have resulted in an average overall increase of 12.4% for all classes of customer.

5 The Board gave notice by advertisement as provided in s. 86 of the *Public Utilities Act*. Thirty-seven intervenors responded. One intervenor was the appellant Dalhousie Legal Aid Service ("DLA").

6 The Board conducted a public hearing over 16 days between November 16, 2004 and January 14, 2005. On March 31, 2005 the Board issued a decision (2005 NSUAR 27). The decision dealt with NSP's requested rate increase and related topics. Only one topic is relevant to this appeal. That is DLA's request that the Board approve a Rate Assistance Program for low income consumers of power.

7 The Board's decision summarized DLA's submission:

9.1 Rate Assistance Program (RAP)

[246] While DLAS has opposed the approval of a FAM [Fuel Adjustment Mechanism] and the SA [Settlement Agreement], and has detailed concerns regarding aspects of customer service provided by NSPI, its main focus at the hearing was the implementation of a proposed Rate Assistance Program ("RAP") to help low-income customers meet their electricity costs.

[247] DLAS filed evidence from several individuals, including Dr. Richard Shillington, a principal of Tristat Resources and Roger Colton, a principal of Fisher, Sheehan & Colton, with respect to this issue. Dr. Shillington, in his direct evidence (Exhibit N-126), outlined the challenging costs of shelter and electricity for low-income Canadians. Mr. Colton's evidence focused on low-income energy assistance programs and his efforts, in a number of US states, in designing rate affordability programs. Mr. Colton's position is that NSPI should "... be directed toward allowing low-income consumers to obtain quality utility service at affordable prices within a reasonable budget constraint." Mr. Colton also submits that the costs of such a program, to be shared by customers, are offset, although perhaps not fully, by savings realized by the Utility resulting from the adoption of a 'universal service program'.

Mr. Colton's report summarized his fixed credit proposal:

Although a variety of percentage-of-income based approaches exists, I recommend the delivery of rate affordability assistance using a fixed credit approach. The fixed credit approach begins as an income-based approach. In order to be eligible for the rate, a household must meet *both* eligibility criteria: (1) that the household income is at or below the Low-Income Cutoff (LICO) for Nova Scotia; and (2) that the household electric burden exceeds the burden deemed to be affordable.

The fixed credit approach differs from a straight percentage of income approach in the calculation of the bill to the household. The fixed credit calculates what bill credit would need to be provided to the household in order to reduce the household's energy bill to a designated percent of income. To calculate the fixed credit involves three steps: (1) calculating a burden-based payment; (2) calculating an annual bill; and (3) calculating the fixed credit necessary to reduce the annual bill to the burden based payment. Each step is explained below.

1. The first step in the fixed credit model is to calculate a burden-based payment. Assume that the household has an annual income of \$8,000 and is required to pay three percent (3%) for its home energy bill. The required household payment is thus \$240. This is simply $\$8,000 \times 3\% = \240 .

Distinctions are also made between heating and non-heating customers. A heating customer should be asked to pay six percent (6%) of the household's income toward her home heating bill, while a non-heating customer would be asked to pay three percent (3%) toward his or her electric bill.

2. The next step is to calculate a projected annual household energy bill. This calculation is to be made using whatever method NSPI *currently* uses to estimate annual bills for other purposes. NSPI, in other words, has an established procedure for estimating an annual bill for purposes of placing residential customers (low-income or not) on a levelized Budget Billing Plan (where bills are paid in equal installments over 12 months). Let me assume for purposes of illustration that this existing process results in an estimated annual bill of \$960.

3. The final step is to calculate the necessary fixed credit to bring the annual bill down to the burden-based payment. Given an annual bill projection of \$960 and a burden-based payment of \$240, the annual fixed credit would need to be \$720 ($\$960 - \$240 = \720). The household's *monthly* fixed credit would be \$60 ($\$720 / 12 = \60).

8 The Board, in response to DLA's request, cited s. 67(1) of the *Public Utilities Act*:

67 (1) All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.

The Board accepted that "all customers, regardless of income, receive 'substantially similar' electrical service from NSP". The Board concluded that it had no power to consider DLA's proposed Rate Assistance Program:

[256] After reviewing the submissions of DLAS, Board Counsel and the relevant provisions of the **Act**, the Board finds that it does not have the statutory authority to approve a RAP. The Board has the authority given to it by the Legislature to perform its duties in accordance with the provisions of the **Act**. The Board's role is to make decisions, based on fact and law, within the parameters of the statutory authority it has been given by the Legislature. The Board's duty is to follow public policy decisions made by the Legislature and expressed in statutes. The Board does not have jurisdiction to establish public policy. That is the role of elected officials who are accountable to the public for this function. It seems almost certain that the RAP, as described by Mr. Colton, would result in the electricity bills of certain customers, depending on their income, being subsidized by other customers. In the Board's view, this is a social and public policy question which falls within the purview of the Legislature rather than the Board. Should NSPI and DLAS wish to pursue this matter with Government, the Board would be pleased to offer assistance with respect to regulatory and ratemaking principles.

9 DLA appeals under s. 30(1) of the *URB Act*, permitting an appeal based on an error of law or jurisdiction.

Issue

10 The issue is whether the Board committed an appealable error by declining to consider the merits of DLA's proposed Rate Assistance Program for low income electricity customers.

Standard of Review

11 Under the pragmatic and functional approach, the court analyses the cumulative effect of four contextual factors: the presence, absence or wording of a privative clause or statutory appeal; the comparative expertise of the tribunal and the court on the appealed or reviewed issues; the purpose of the governing legislation; and the nature of the question, fact, law or mixed. The ultimate question is whether the legislature intended that the issue under review be left to

the tribunal. From this analysis the court selects, for each issue, a standard of review of correctness, reasonableness or patent unreasonableness: *Pushpanathan v. Canada (Minister of Employment & Immigration)*, [1998] 1 S.C.R. 982 (S.C.C.), at ¶ 26; *Q. v. College of Physicians & Surgeons (British Columbia)*, [2003] 1 S.C.R. 226 (S.C.C.), at ¶ 26-35; *Ryan v. Law Society (New Brunswick)*, [2003] 1 S.C.R. 247 (S.C.C.), at ¶ 27; *Voice Construction Ltd. v. Construction & General Workers' Union, Local 92*, [2004] 1 S.C.R. 609 (S.C.C.) at ¶ 15-19; *Baker v. Canada (Minister of Citizenship & Immigration)*, [1999] 2 S.C.R. 817 (S.C.C.), at ¶ 55-62; *Granite Environmental Inc. v. Nova Scotia (Labour Relations Board)*, 2005 NSCA 141 (N.S. C.A.), at ¶ 21; *N.S.T.U. v. Nova Scotia Community College*, 2006 NSCA 22 (N.S. C.A.), at ¶ 11; *Capital District Health Authority v. N.S.G.E.U.*, 2006 NSCA 44 (N.S. C.A.), at ¶ 36.

12 In *Johnson v. Nova Scotia*, 2005 NSCA 99 (N.S. C.A.), at ¶ 33-46, Justice Oland applied the four contextual factors to the expropriation powers of the Utility and Review Board, and concluded:

[46] After considering the four contextual factors of the functional and pragmatic approach, in my view the standard of review to be applied to questions of law, such as any entitlement for compensation for owner's time and for pension loss, the standard of review is correctness. For questions of mixed law and fact, such as matters related to compensation for market value and injurious affection, the standard is patent unreasonableness. For findings of fact, the standard is patent unreasonableness.

Though there is correspondence among the Board's different functions, the pragmatic and functional analysis for expropriation is not necessarily commutable to rate-making. So I will consider the four contextual factors from the perspective of utility rating.

13 Section 26 of the *URB Act* says that the Board's findings of fact are "binding and conclusive", while s. 30(1) prescribes an appeal to this court on questions of law or jurisdiction. The Legislature contemplated a serious judicial role in the review for legal error, particularly on threshold issues.

14 Section 44 of the *Public Utilities Act* entitles the Board to fix rates "as it deems just". Section 67(1) quoted earlier directs equal charges for "similar circumstances and conditions" of service and authorizes the Board to enact regulations that define "substantially similar circumstances and conditions". The Board has a standing membership, repeatedly has examined NSP rate applications and has developed a body of governing jurisprudence. Clearly, the Board has more expertise than the court in the architecture of rate-making.

15 In *Nova Scotia (Public Utilities Board) v. Nova Scotia Power Corp.* (1976), 18 N.S.R. (2d) 692 (N.S. C.A.), at ¶ 17, Chief Justice MacKeigan summarized the purposes of the *Public Utilities Act*:

17 The scheme of regulation established by the Act envisages and indeed compels control by the Board of all aspects of a utility's operation in providing a controlled service. Two great objects are enshrined — that all rates charged must be just, reasonable and sufficient and not discriminatory or preferential, and that the service must be adequately, efficiently and reasonably supplied to the public. Almost all provisions of the Act are directed toward securing these two objects — that a public utility give adequate service and charge only reasonable and just rates.

The legislation considered by Chief Justice MacKeigan included ss. 42 and 63(1), the equivalents to the current ss. 44 and 67(1) that are central to this appeal (see *NS (PUB)* at ¶ 15, 28).

16 DLA says its argument is "jurisdictional" and therefore the standard of review must be correctness. It may be that, after the court reviews the four contextual factors, true jurisdictional issues usually will attract the correctness standard. But I disagree that every labelled "jurisdictional" argument is tethered to correctness, and I reiterate this court's comment in *Capital District Health Authority v. N.S.G.E.U.* :

[28] . . . The court no longer reviews for pigeonholed "jurisdictional errors." The phrase "goes to jurisdiction" describes a type of issue for which the proper standard of review is correctness, after the reviewing court has performed the pragmatic and functional analysis. But the "jurisdictional" inquiry is not a substitute for the pragmatic

and functional approach. [Citing *Pushpanathan* at ¶ 28; *Dr. Q.* at ¶ 20-25; *Voice* at ¶ 21; *Granite* at ¶ 41(b) and *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 (S.C.C.) at ¶ 21-32.]

17 A similar issue arose in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4 (S.C.C.). A public utility applied to Alberta's Energy and Utilities Board for approval of a sale of assets and allocation of the sale proceeds. The Board allocated a portion of the proceeds of sale to the rate-paying customers. On appeal from the judicial review, the Supreme Court of Canada considered whether the Board had statutory authority to allocate any sale proceeds to the ratepayers. Despite the "jurisdictional" aspect of the issue, Justice Bastarache for the majority said that the pragmatic and functional analysis was necessary:

23 In the case at bar, one should avoid a hasty characterizing of the issue as "jurisdictional" and subsequently be tempted to skip the pragmatic and functional analysis. A complete examination of the factors is required.

In *ATCO*, a threshold issue of statutory interpretation determined whether the Board could exercise its core functions. Justice Bastarache selected a correctness standard, having reasoned as follows:

30 While at first blush the purposes of the relevant statutes and of the Board can be conceived as a delicate balancing between different constituencies, i.e., the utility and the customer, and therefore entail determinations which are polycentric (*Pushpanathan*, at para. 36), the interpretation of the enabling statutes and the particular provisions under review (s. 26(2)(d) GUA and s. 15(3)(d) AEUBA) is not a polycentric question, contrary to the conclusion of the Court of Appeal. It is an inquiry into whether a proper construction of the enabling statutes gives the Board jurisdiction to allocate the profits realized from the sale of an asset. The Board was not created with the main purpose of interpreting the AEUBA, the GUA or the PUBA in the abstract, where no policy consideration is at issue, but rather to ensure that utility rates are always just and reasonable (see *Atco Ltd.*, at p. 576). In the case at bar, this protective role does not come into play. Hence, this factor points to a less deferential standard of review.

31 Fourth, the nature of the problem underlying each issue is different. The parties are in essence asking the Court to answer two questions (as I have set out above), the first of which is to determine whether the power to dispose of the proceeds of sale falls within the Board's statutory mandate. The Board, in its decision, determined that it had the power to allocate a portion of the proceeds of a sale of utility assets to the ratepayers; it based its decision on its statutory powers, the equitable principles rooted in the "regulatory compact" (see para. 63 of these reasons) and previous practice. This question is undoubtedly one of law and jurisdiction. The Board would arguably have no greater expertise with regard to this issue than the courts. A court is called upon to interpret provisions that have no technical aspect, in contrast with the provision disputed in *Barrie Public Utilities v. Canadian Cable Television Assn.*, [2003] 1 S.C.R. 476, 2003 SCC 28, at para. 86. The interpretation of general concepts such as "public interest" and "conditions" (as found in s. 15(3)(d) of the AEUBA) is not foreign to courts and is not derived from an area where the tribunal has been held to have greater expertise than the courts. ...

32 In light of the four factors, I conclude that each question requires a distinct standard of review. To determine the Board's power to allocate proceeds from a sale of utility assets suggests a standard of review of correctness. As expressed by the Court of Appeal, the focus of this inquiry remains on the particular provisions being invoked and interpreted by the tribunal (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) and "goes to jurisdiction" (*Pushpanathan*, at para. 28). Moreover, keeping in mind all the factors discussed, the generality of the proposition will be an additional factor in favour of the imposition of a correctness standard, as I stated in *Pushpanathan*, at para. 38:

... the broader the propositions asserted, and the further the implications of such decisions stray from the core expertise of the tribunal, the less likelihood that deference will be shown. Without an implied or express legislative intent to the contrary as manifested in the criteria above, legislatures should be assumed to have left highly generalized propositions of law to courts.

18 The Board's rate-making power is a core function entitled to deference. But the issue here is whether the statute precludes the Board from exercising that power. After considering the four contextual factors, and given the statutory right of appeal and the comments in *ATCO*, in my view the Legislature intended no deference on that issue. The threshold legal question is governed by a correctness standard.

Did the Board Err in Law by Declining to Consider the Rate Assistance Program?

19 This is a question of statutory interpretation. The words of a statute are read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme of the *Act*, the object of the *Act* and the intention of the Legislature: *Parry Sound (District) Welfare Administration Board v. O.P.S.E.U., Local 324*, 2003 SCC 42 (S.C.C.), at ¶ 41; *R. v. Sharpe*, [2001] 1 S.C.R. 45 (S.C.C.) at ¶ 33; *Nova Scotia (Minister of Health) v. G. (R.)*, 2005 NSCA 59 (N.S. C.A.), at ¶ 24; *Doctors Nova Scotia v. Nova Scotia (Department of Health)*, 2006 NSCA 59 (N.S. C.A.), at ¶ 25.

20 DLA focusses on the grammatical and ordinary meaning of the Board's general rate-making power in s. 44 of the *Public Utilities Act*:

44 The Board may make from time to time such orders as it deems just in respect to the tolls, rates and charges to be paid to any public utility for services rendered or facilities provided, and amend or rescind such orders or make new orders in substitution therefor.

DLA submits that the Board is mandated to consider whether a rate assistance program for low income customers is "just".

21 The court must also grapple with the basis of the Board's ruling, s. 67(1):

67 (1) All tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate, and the Board may by regulation declare what shall constitute substantially similar circumstances and conditions.

DLA says that its Rate Assistance Program would provide a credit against the rate, but would not alter the rate itself. DLA says that s. 67(1) refers to pure "rates", not credits, and is irrelevant to DLA's Program.

22 In my respectful view, DLA's rate/credit distinction is artificial and analytically flawed. A gross rate subject to an automatic credit is just a net rate charged to the customer by NSP. The "charge" under s. 67(1) is the net amount. The Board's "rate" making power is not a blind stab at gross revenue. The rating involves a projection of NSP's expenses, net income and rate of return. The Board must consider the effect of a credit against rates just as it must consider NSP's expenses to generate power. DLA cites s. 44 of the *Public Utilities Act* as authority for its Rate Assistance Program, including the credit. Yet, s. 44, quoted earlier, empowers the Board to approve "tolls, rates and charges", saying nothing of "credits". Rate credits are integrated with "rates and charges" in s. 67(1) no less than rate credits pertain to the Board's "rating" power in s. 44, upon which DLA relies.

23 DLA's factum said that low income customers do not have "substantially similar circumstances" to higher income customers. So, different rates would not be barred by s. 67(1). At the appeal hearing DLA's counsel retreated somewhat from this submission.

24 With respect, the factum's submission misinterprets s. 67(1). The provision refers to "substantially similar circumstances and conditions *in respect of service of the same description*." To justify a rate difference, the relevant dissimilarity is not in customers' incomes. It is in the service from NSP. The Board accepted, and there is no basis to question, that NSP provides substantially similar electrical service whatever the domestic customer's income.

25 Section 67(1) is mandatory. The rates and charges "shall always . . . be charged equally" to persons of similar circumstances and conditions in respect of service. The statute does not endow the Board with discretion to consider the social justice of reduced rates for low income customers. It is not for the Board or this court to read into s. 67(1) the words:

. . . similar circumstances and conditions in respect of *the income level of customers and* service of the same description,

It is for the Legislature to decide whether to expand the Board's purview with the italicized words.

26 This point is illustrated by *Allstream Corp. v. Bell Canada*, 2005 FCA 247 (F.C.A.), cited by DLA. The Federal Court of Appeal upheld the decision of the CRTC to provide low rates to schools and municipalities for fibre optic service. DLA's factum says:

This case stands for the proposition that the jurisdiction to regulate utilities *includes* non cost-based rates and by analogy would include programs similar to a rate assistance program for low income consumers. [emphasis in original]

27 I disagree with DLA's measure of *Allstream's* reach. The Federal Court of Appeal said:

34. ... It is apparent that the Commission was greatly concerned about the effect of a denial of services on the communities concerned and the dislocation of complex equipment and facility configurations at a significant cost and to the detriment of school boards and municipalities in the relevant areas and that such concerns outweighed, in its view, Bell's failure to seek prior approval of these rates. These are considerations that a specialized board can entertain and weigh relative to other considerations. It is true that these considerations are not purely economic in the sense referred to by the appellant such as costs, investment, allowance for necessary working capital, rate of return, etc. These considerations, however, are *part of the Commission's wide mandate under section 7*, a mandate it alone possesses and are quite distinct from the grant of a rate under paragraph 27(6)(b) of the Act, a power the Commission did not invoke. [emphasis added]

Section 47(a) of the *Telecommunications Act*, S.C. 1993, c. 38 directed the CRTC to implement the telecommunications policy objectives from s. 7. Those included enriching the "social and economic fabric", rendering "affordable" and "accessible" service, and responding to "the economic and social requirements of users." [legislation quoted in ¶ 10 of *Allstream*]. Nova Scotia's Utility and Review Board has no such statutory mandate.

28 The grammatical and ordinary interpretation of s. 67(1), outlined above, is consistent with the statutory context, scheme and object of the *Act*, and intention of the Legislature.

29 The *Act* connects the Board's rate-making to NSP's "service". Section 2(f) of the *Public Utilities Act* defines "service" as including:

(iii) the production, transmission, delivery or furnishing to or for the public by a public utility for compensation of electrical energy for purposes of heat, light and power,

Section 44 authorizes the Board to make rates "for services rendered or facilities provided". Section 52 requires the public utility to "furnish services and facilities that are adequate, just and reasonable". Section 64(1) prohibits the utility from charging compensation for any "service" until the Board has approved the rate for that service. Section 107, entitled "offence and penalty for unjust discrimination", prohibits the utility from charging "for any service" a rate that is higher or lower than charged to any other person "for a like and contemporaneous service".

30 Section 73 of the *Public Utilities Act* allows preferential rates for

(3) . . . a senior citizens club, service club, volunteer fire department, a Royal Canadian Legion, community hall or recreational facility owned by a community and used for general community purposes, a charitable or religious organization or institution . . .

and authorizes the Lieutenant Governor-in-Council to extend this list by order-in-council.

31 The legislative context ties the Board's rate levels to the utility's services. The Legislature enacts, or assigns to order-in-council, non-compliant rates for specific classes of customer based on social criteria.

32 The Board sets rates for a utility that has a virtual monopoly on the supply of electric power. [The Board's decision discusses this process: \(2005 NSUARB 27\)](#)

[17] . . . NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the utility is permitted, under the *Act*, to recover the reasonable and prudent costs of providing the service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.

[18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.

[19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly.

33 I agree with this portrayal of the background to the Board's rate-making function. The Board's regulatory power is a proxy for competition, not an instrument of social policy.

34 DLA points to the Board's approval of rates that prefer large industrial power customers. In *Nova Scotia Power Inc., Re*, [\[2000\] N.S.U.R.B.D. No. 72](#) (N.S. Utility & Review Bd.), the Board approved NSP's application for a load retention rate. This rate would be determined between the individual customer and NSP, then submitted to the Board for approval. Paragraph 5 of the Board's decision describes the features of NSP's proposed load retention rate:

5 NSPI states in its application that "the proposed rate is an appropriate approach to retaining existing customers who, in the absence of this rate, would reduce their purchases from the Company, to the detriment of all other customers". The rate would be available to customers "who are considering an alternate supply of at least 2000 KVA or 1800 KW". It would not be available for new load. The rate would only be available if the following conditions are satisfied:

1. The customer's option to use a supply of power and energy (alternate supply) other than NSPI's is both technically and economically feasible.
2. Retaining the customer's load, at the price offered by this rate, is better for other electric customers than losing the customer load in question.
3. The price offered by this rate is not less than that necessary to make the customer in question indifferent with respect to alternate supply versus continuing to purchase the electric power and energy from NSPI.

DLA says that, if the Board can approve a load retention rate for large industrial customers, then it can approve a rate assistance program for low income customers.

35 The Board's decision in [2000] N.S.U.R.B.D. No. 72 (N.S. Utility & Review Bd.) is not under appeal. Neither are its decisions on similar issues such as the extra large industrial interruptible rate: *Nova Scotia Power Inc., Re, 2003 NSUARB 6* (N.S. Utility & Review Bd.) and *Nova Scotia Power Inc., Re, 2003 NSUARB 91* (N.S. Utility & Review Bd.). I make no comment on those rulings, except to say that they do not support DLA's submission here that the Board can implement social policy. The Board's approval of the load retention rate was premised on the finding that, otherwise, the large customer could leave NSP, obtain its energy from another source, and this would hike NSP's rates to its remaining customers. The Board's approach affirms the Board's role as a competition surrogate. The Board's load retention rate recognizes the microeconomic reality that NSP is not an absolute energy monopoly with a vertical customer demand curve, and is subject to elastic demand from high volume customers with other energy options. No such factors govern DLA's proposed Rate Assistance Program.

36 DLA says that legislation should be interpreted in a manner that is consistent with the *Charter of Rights and Freedoms*. DLA's counsel makes a forceful submission that the impoverished are a protected category under s. 15 and, following *Eldridge v. British Columbia (Attorney General)*, [1997] 3 S.C.R. 624 (S.C.C.), this court may direct the institution of a program to ameliorate their disadvantage. DLA's submission is interpretive and does not challenge the validity of the legislation.

37 I make no comment on s. 15. The statutory language does not accommodate the suggested construction.

38 The constructive principle applies only when the statute is ambiguous. In *R. v. Jackpine*, 2006 SCC 15 (S.C.C.), at ¶ 18, Justice Charron for the majority said:

It has long been accepted that courts should apply and develop common law rules in accordance with the values and principles enshrined in the *Charter*: *RWDSU v. Dolphin Delivery Ltd.*, [1986] 2 S.C.R. 573, at p. 603; *Cloutier v. Langlois*, [1990] 1 S.C.R. 158, at p. 184; *R. v. Salituro*, [1991] 3 S.C.R. 654, at p. 675; *R. v. Golden*, [2001] 3 S.C.R. 679, 2001 SCC 83, at para. 86; *R. v. Mann*, [2004] 3 S.C.R. 59, 2004 SCC 52, at paras.17-19. However, it is equally well settled that, in the interpretation of a statute, *Charter* values as an interpretative tool can only play a role where there is a genuine ambiguity in the legislation. In other words, where the legislation permits two different, yet equally plausible, interpretations, each of which is equally consistent with the apparent purpose of the statute, it is appropriate to prefer the interpretation that accords with *Charter* principles. However, where a statute is not ambiguous, the court must give effect to the clearly expressed legislative intent and not use the *Charter* to achieve a different result. In *Bell ExpressVu Ltd. Partnership v. Rex*, [2002] 2 S.C.R. 559, 2002 SCC 42, at para. 62, Iacobucci J., writing for a unanimous court, firmly reiterated this rule:

... to the extent this Court has recognized a "*Charter* values" interpretive principle, such principle can only receive application in circumstances of genuine ambiguity, i.e., where a statutory provision is subject to differing, but equally plausible, interpretations. [Emphasis in original.]

To the same effect: *Bell ExpressVu Ltd. Partnership v. Rex*, [2002] 2 S.C.R. 559 (S.C.C.) at ¶ 27-30, 60-66.

39 Section 67(1) is not ambiguous: "rates . . . shall always . . . be charged equally to all persons and at the same rate" in substantially similar "circumstances and conditions in respect of service of the same description". The Board cannot reduce the rate to a low income customer who receives the same service as a high income customer. There is no latitude for the interpretive presumption.

Conclusion

40 The Board did not err in its conclusion that s. 67(1) precludes the Board from considering DLA's rate assistance program for low income customers. I would dismiss the appeal without costs.

Appeal dismissed.

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COURT OF APPEAL FOR BRITISH COLUMBIA

Citation: *British Columbia Old Age Pensioners’
Organization v. British Columbia Utilities
Commission*,
2017 BCCA 400

Date: 20171117
Dockets: CA44248; CA44557

Docket: CA44248

Between:

**British Columbia Old Age Pensioners’ Organization, Active Support Against
Poverty, Council of Senior Citizens’ Organizations of BC, Disability Alliance
BC, Together Against Poverty Society, and the Tenant Resource and Advisory
Centre (“BCOAPO et al.”) and Movement of United Professionals**

Appellants
(Intervenors)

And

British Columbia Utilities Commission

Respondent
(Administrative Tribunal)

And

British Columbia Hydro and Power Authority

Respondent
(Applicant)

And

**FortisBC Energy Inc. and FortisBC Inc. (collectively, “Fortis”), Commercial
Energy Consumers’ Association of British Columbia, British Columbia
Sustainable Energy Association, Sierra Club of British Columbia, Association
of Major Power Customers, Non Integrated Areas Ratepayers Group, Zone II
Ratepayers Group**

Respondents
(Intervenors)

And

Attorney General of British Columbia

Respondent

- and -

Docket: CA44557

Between:

**British Columbia Old Age Pensioners' Organization, Active Support Against
Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance
BC, Together Against Poverty Society, and the Tenant Resource and Advisory
Centre ("BCOAPO et al.") and Movement of United Professionals**

Appellants
(Intervenors)

And

British Columbia Utilities Commission

Respondent
(Administrative Tribunal)

And

British Columbia Hydro and Power Authority

Respondent
(Applicant)

And

**FortisBC Energy Inc. and FortisBC Inc. (collectively, "Fortis"), Commercial
Energy Consumers' Association of British Columbia, British Columbia
Sustainable Energy Association, Sierra Club of British Columbia**

Respondents
(Intervenors)

And

Attorney General of British Columbia

Respondent

Before: The Honourable Mr. Justice Goepel
(In Chambers)

On appeal from: Decisions and Orders of the British Columbia Utilities Commission,
dated January 20, 2017 (Order Number G-5-17) and
June 2, 2017 (Order Number G-87-17).

**British Columbia Old Age Pensioners' Organization v. British Columbia
Utilities Commission****Page 3**

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Place and Date of Hearing:

Vancouver, British Columbia
September 19, 2017

Place and Date of Judgment:

Vancouver, British Columbia
November 17, 2017

Summary:

BCOAPO and MoveUp apply for leave to appeal two orders of the BC Utilities Commission. The orders were made in the context of a Rate Design Application submitted by BC Hydro, which proposed utility rates for classes of customers. BCOAPO and MoveUp had intervened in the application process, requesting the implementation of strategies to assist low-income ratepayers. In the first order, the Commission denied most of the low-income proposals on the basis that it lacked jurisdiction under the Utilities Commission Act to set low-income rates without an economic or cost of service justification. The second order denied a request for reconsideration.

Held: Applications for leave to appeal dismissed. In the circumstances of this case the decision of whether or not to grant leave comes down to a consideration of the merits. Assessing whether there is some prospect the appeal will succeed on its merits must be done in light of the standard of review on which the merits of the appeal would be judged. In this case, the Commission interpreted and applied provisions of its home statute and thus its decision would be reviewed on a standard of reasonableness. Given the standard of review, this appeal has no prospect of success.

Reasons for Judgment of the Honourable Mr. Justice Goepel:**INTRODUCTION**

[1] The applicants, British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre (collectively, "BCOAPO") and the Movement Of United Professionals ("MoveUp") seek leave under s. 101 of the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 [UCA] to appeal the following orders of the British Columbia Utilities Commission:

1. Order G-5-17, pronounced on January 20, 2017 (the "Original Decision"); and
2. Order G-87-17, pronounced on June 2, 2017 (the "Reconsideration Decision").

[2] The orders were made in the context of a Rate Design Application submitted by BC Hydro, which proposed utility rates for classes of customers. BCOAPO and MoveUp had intervened in the application process, requesting the implementation of strategies to assist low-income ratepayers. In the first order, the Commission denied most of the low-income proposals on the basis that it lacked jurisdiction under the *UCA* to set low-income rates without an economic or cost of service justification. The second order denied a request for reconsideration

[3] The application for leave is opposed by the respondents, British Columbia Hydro and Power Authority (“BC Hydro”) and FortisBC Energy Inc. and FortisBC Inc. (collectively, “Fortis”). BC Hydro and Fortis both submit that if leave is granted, it should be limited to the Reconsideration Decision.

[4] The Commission takes no position on the application for leave to appeal from the Reconsideration Decision. It does submit, however, that it is improper to grant leave to appeal the Original Decision because that decision has been the subject of reconsideration by the Commission and only the Commission’s final decision should be subject to appellate review.

[5] For the reasons that follow, I would dismiss the applications for leave to appeal.

BACKGROUND

A. Legislative Scheme

[6] BC Hydro is the publicly owned monopoly electricity provider to the vast majority of the province. The Commission is empowered to regulate BC Hydro to ensure its quality of service, infrastructure, operations and rates are in the public interest. Pursuant to sections 23, 38, 59 and 60 of the *UCA*, the Commission is charged with ensuring that utilities provide safe, adequate, efficient and secure service to their customers and that the rates are fair, just and reasonable, and not unduly discriminatory or preferential. Those sections read as follows:

General supervision of public utilities

23 (1) The commission has general supervision of all public utilities and may make orders about

- (a) equipment,
- (b) appliances,
- (c) safety devices,
- (d) extension of works or systems,
- (e) filing of rate schedules,
- (f) reporting, and
- (g) other matters it considers necessary or advisable for
 - (i) the safety, convenience or service of the public, or
 - (ii) the proper carrying out of this Act or of a contract, charter or franchise involving use of public property or rights.

(2) Subject to this Act, the commission may make regulations requiring a public utility to conduct its operations in a way that does not unnecessarily interfere with, or cause unnecessary damage or inconvenience to, the public.

Public utility must provide service

38 A public utility must

- (a) provide, and
- (b) maintain its property and equipment in a condition to enable it to provide,

a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.

Discrimination in rates

59 (1) A public utility must not make, demand or receive

- (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or
- (b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

- (a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or
- (b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

- (a) whether a rate is unjust or unreasonable,
 - (b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or
 - (c) whether a service is offered or provided under substantially similar circumstances and conditions.
- (5) In this section, a rate is “unjust” or “unreasonable” if the rate is
- (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
 - (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
 - (c) unjust and unreasonable for any other reason.

Setting of rates**60** (1) In setting a rate under this Act

- (a) the commission must consider all matters that it considers proper and relevant affecting the rate,
 - (b) the commission must have due regard to the setting of a rate that
 - (i) is not unjust or unreasonable within the meaning of section 59,
 - (ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and
 - (iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,
 - (b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and
 - (c) if the public utility provides more than one class of service, the commission must
 - (i) segregate the various kinds of service into distinct classes of service,
 - (ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and
 - (iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.
- (2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value

of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

[7] Pursuant to s. 79 of the *UCA*, determinations of the Commission on questions of fact within its jurisdiction are binding and conclusive on all persons and all courts.

[8] Section 99 gives the Commission the power to reconsider a decision.

[9] Pursuant to s. 105(1) of the *UCA*, the Commission has exclusive jurisdiction in all cases and for all matters in which jurisdiction is confirmed on the Commission by statute. Section 105(2) provides that unless otherwise provided in the *UCA*, any order or decision of the Commission must not be questioned, reviewed or restrained by or on application for judicial review or other process or proceeding in any court.

[10] Section 101 of the *UCA* provides that an appeal lies from of an order or decision of the Commission to the Court of Appeal with leave of a justice of that court. Appeals from the Commission are restricted to questions of law or jurisdiction: *Plateau Pipe Line Ltd. v. British Columbia Utilities Commission*, 2002 BCCA 246 at paras. 8–9.

B. Procedural History

[11] The orders which are the subject matter of these leave applications were made in the context of a Rate Design Application (“RDA”). In an RDA the Commission is tasked with determining utilities rates for various classes of customers. The Commission hears evidence and submissions from the applicant utility and intervenor groups regarding the costs to serve each rate group, and the

proper rate structure to recover those costs from each rate group. The Commission then makes a determination regarding the costs of service, rate structures, and terms and conditions of service for residential, business, industrial and all other customers.

[12] On September 24, 2015, BC Hydro filed an application with the Commission, known as the 2015 RDA. It was the first comprehensive rate design application since 2007. BCOAPO, Move Up and Fortis were amongst the groups granted intervenor status in the 2015 RDA.

[13] BCOAPO asked the Commission to order BC Hydro to implement a strategy to assist low-income ratepayers. More specifically, BCOAPO asked that the Commission direct BC Hydro to:

- (a) implement an “essential services usage block” (“ESUB”) rate, which would allow low-income customers to receive the first 400 kWh of service each month at a discount; and
- (b) amend the BC Hydro electric tariff to exempt low-income customers from late payment, minimum reconnection and account charges and security deposits (collectively, the “Low-Income Proposals”).

[14] The Low-Income Proposals were opposed by BC Hydro as well as two intervenor groups, including Fortis.

THE ORIGINAL DECISION

[15] On January 20, 2017, the Commission issued the Original Decision and accompanying reasons. The Commission denied the majority of the Low-Income Proposals. It found that the *UCA* did not provide the Commission with the jurisdiction to approve a low-income rate in the absence of an economic or a cost of service justification. It found as a fact that it did not cost BC Hydro less to serve low-income customers than it did to serve other residential customers. It further found that low-income rates unsupported by an economic or cost of service justification would be

unjust, unreasonable and unduly discriminatory and therefore not in accordance with s. 59 of the *UCA* — and accordingly not within the Commission's jurisdiction to approve. Order G-5-17 contains the following paragraphs relevant to this appeal:

14. [BCOAPO's] request to establish an essential services usage block (ESUB) rate for qualified low-income ratepayers is denied.
16. BCOAPO's proposals to amend the Electric Tariff to exempt low-income customers from the minimum reconnection charge and account charge and to waive security deposits for low-income customers are denied.
17. BCOAPO's proposal to exempt low-income customers from late payment charges ... [is] denied.

THE RECONSIDERATION DECISION

[16] On February 17, 2017, BCOAPO filed a request pursuant to s. 99 of the *UCA* that the Commission reconsider its decision. The grounds advanced were that the Commission erred in law in finding sections 23, 38, 59 and 60 of the *UCA* do not provide the Commission with jurisdiction to order or approve low-income rates.

[17] The Commission addresses reconsideration applications in two phases. The first phase is a preliminary examination: essentially a threshold test. In the case of a reconsideration application based on errors of law with respect to jurisdiction, the Commission examines the following two criteria to determine whether a reconsideration application should proceed to the second phase and be considered on its merits: (a) whether the claim of error is substantiated on a *prima facie* basis; and (b) whether the error has material implications.

[18] In the Original Decision, the Commission found no evidence of legislative intent to provide the Commission with jurisdiction to set low-income rates and no evidence the legislature intended the *UCA* to provide jurisdiction for low-income rates in the absence of economic or cost of service justification. It found as a fact

that low-income rates unsupported by an economic or cost of service justification are unjust, unreasonable and unduly discriminatory, and are therefore not in accordance with s. 59 of the *UCA*.

[19] On June 2, 2017, by way of Order G-87-17 the Commission denied the reconsideration request finding the errors claimed had not been substantiated on a *prima facie* basis. In the result, the reconsideration application did not proceed to phase two and was not considered on its merits.

TEST FOR LEAVE TO APPEAL

[20] Pursuant to s. 101 of the *UCA*, an appeal lies to this Court with leave of a justice. The judge who hears the leave application acts as a gatekeeper. The judge's task is to ensure judicial resources are not expended on matters that do not merit the attention of a division of the Court: *Teck Cominco Metals Ltd. v. British Columbia (Minister of Revenue)*, 2009 BCCA 3 (in Chambers) at para. 27.

[21] The factors to be considered in deciding whether leave to appeal from a statutory tribunal should be granted were summarized in *Queens Plate Development Ltd. v. Vancouver Assessor, Area 09* (1987), 16 B.C.L.R. (2d) 104 at 109–110:

- (a) whether the proposed appeal raises a question of general importance as to the extent of jurisdiction of the tribunal appealed from ...;
- (b) whether the appeal is limited to questions of law involving:
 - (i) the application of statutory provisions ...;
 - (ii) a statutory interpretation that was particularly important to the litigant ...; or
 - (iii) interpretation of standard wording which appears in many statutes ...;
- (c) whether there was a marked difference of opinion in the decisions below and sufficient merit in the issue put forward ...;
- (d) whether there is some prospect of the appeal succeeding on its merits ... although there is no need for a justice before whom leave is argued to be convinced of the merits of the appeal, as long as there are substantial questions to be argued;
- (e) whether there is any clear benefit to be derived from the appeal ...; and

(f) whether the issue on appeal has been considered by a number of appellate bodies ...

[Case citations omitted.]

[22] Determining whether the issue raised by an application for leave to appeal has arguable merit must be done in light of the standard of review on which the merits of the appeal will be judged: *Sattva Capital Corp. v. Creston Moly Corp.*, 2014 SCC 53 at para. 75. While *Sattva* concerned leave to appeal a decision under the *Commercial Arbitration Act*, R.S.B.C. 1996, c. 55, the same principle applies to a leave application pursuant to s. 101 of the *UCA*: *Collins v. British Columbia Utilities Commission*, 2012 BCCA 455.

POSITIONS ON APPLICATION

[23] The applicants submit they should be granted leave to appeal both the Original Decision and the Reconsideration Decision. They submit the proposed appeal raises an important question about the Commission's jurisdiction under the *UCA* to order or approve low-income rates. They submit the answer to this jurisdictional question will have significant implications for BC Hydro, other utilities and low-income ratepayers all over the province.

[24] The applicants submit that whether the Commission has jurisdiction under the *UCA* to approve low-income rates is a question of statutory interpretation which should be determined on the basis of correctness. They submit the Commission erred in law in finding that it had no jurisdiction under the *UCA* to set low-income rates. The applicants submit that the appeals would have the clear benefit of settling an important jurisdictional question and would clarify whether the Commission can, as part of its public interest function, make distinctions between customers based on income to ensure vulnerable ratepayers can access essential services. The applicants note that while the issue of a regulatory body's jurisdiction to order low-income rates has been considered by other appellate bodies, none have considered the specific legislation set out in the *UCA*.

[25] In response, BC Hydro and Fortis both submit that if there is an appeal, it would lie only from the Reconsideration Decision. They submit that the factors in the *Queens Plate* test have not been met and the application for leave to appeal should be dismissed. In that regard, they submit that the proposed appeal does not raise a true question of jurisdiction that would justify appellate review. Furthermore, they submit the appeal has no prospect of success given the high level of deference that would be shown to the Commission, which interpreted and applied provisions of its home statute. They submit the applicants have failed to show the appeal has some prospect of success or that there is a substantial question to be argued. They further submit the Commission did in fact consider the applicants' proposals and found as a fact the low-income rates would be unduly discriminatory and therefore not in accordance with s. 59 of the *UCA*. They submit this finding of fact cannot be challenged on appeal.

[26] The Commission takes no position as to whether or not leave to appeal should be granted. It does however submit that if leave is granted, it should be limited to the Reconsideration Decision.

DISCUSSION

A. Which Decision Can Be Appealed?

[27] The Commission, BC Hydro and Fortis all submit that if leave is to be granted, it should only be from the Reconsideration Decision. The applicants do not seriously argue otherwise.

[28] This Court in *Yellow Cab Company Ltd. v. Passenger Transportation Board*, 2014 BCCA 329, set out the framework governing the determination of whether leave to appeal should be from a tribunal's original or reconsideration decision. Where a party has taken advantage of a tribunal's reconsideration power, and the tribunal has undertaken the reconsideration, the reconsideration decision represents the final decision of the tribunal and it is the decision which should be reviewed: *Yellow Cab Company Ltd.* at para. 40.

[29] The original decision of course gives rise to the reconsideration decision. It forms part of the appeal record and will inform the court's review of the reconsideration which is, in this case, an affirmation of the original order. This is the situation that arose in *Zellstoff Celgar Limited Partnership v. British Columbia Hydro and Power Authority et al.* (21 October 2014), Vancouver CA041888; CA042066 (B.C.C.A. in Chambers). In that case, as in this, the parties sought leave to appeal both the original and reconsideration decisions of the Commission. Madam Justice MacKenzie held that leave should only be granted in regard to the reconsideration decision. She noted that since the original decision forms part of the record and will inform the court's review on appeal, there was no prejudice in granting leave to appeal only the reconsideration decision. The same considerations apply in this case. If leave to appeal is to be granted, leave should only be granted with respect to the Reconsideration Decision.

B. Should Leave Be Granted?

[30] I turn to the question of whether leave to appeal should be granted. This requires a consideration of the *Queens Plate* factors. The applicants place particular emphasis on factors (a), (b) and (d).

[31] In their submission, the applicants stress that the proposed appeal raises a question of general importance concerning the Commission's jurisdiction. They submit that the jurisdictional question is critically important, as it will determine whether the Commission is empowered to order BC Hydro to implement low-income rates. They submit the proposed appeal is limited to questions involving statutory interpretation and will focus on the Commission's finding that sections 23, 38, 59 and 60 of the *UCA* do not provide the Commission with the jurisdiction to order and approve low-income rates. They submit the Commission erred in law in finding that the *UCA* did not confer jurisdiction on the Commission to set low-income rates. They submit the appeal has some prospect of success and their submissions raise a substantial question to be tried.

[32] The applicants further submit pursuant to factor (e) that there is a clear public benefit to be derived from the appeal. In this regard, they submit that the impact of the decision on BC Hydro's low-income customers is severe. They submit the appeal can settle an important jurisdictional question and if successful, will enable the Commission to consider a substantive issue of important public interest.

[33] The applicants also point out that the issue of a regulatory body's jurisdiction to order low-income rates has been considered by other appellate bodies, albeit not with respect to the specific legislation that governs the Commission. In that regard, they point to the decisions in *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74; *Advocacy Centre for Tenants-Ontario v. Ontario Energy Board*, 293 D.L.R. (4th) 684, 2008 CanLII 23487 (Ont. S.C.J.) and a recent Manitoba hydro general rate application: Manitoba Public Utilities Board Order No. 73/15, Final Order with respect to Manitoba Hydro's 2014/15 and 2015/16 General Rate Application.

[34] In my respectful opinion, the question of whether or not to grant leave on this application comes down to a consideration of the merits.

[35] The merits analysis plays a major role in the courts' gatekeeper function. In *Collins*, Mr. Justice Chiasson in discussing the merits test observed:

[32] It is apparent to me that this Court equates "some prospect of success" with "a substantial question to be argued". I would not apply a test that limits the consideration to whether a proposed appeal is "not wholly devoid of merit". In my mind, that is not consistent with the gatekeeper function described by Frankel J.A. It also is not consistent with the development of the reasonableness standard in the law of judicial review and the deference owed by courts to tribunals where the issue does not concern true jurisdiction, and particularly, where the issue involves the construction of a tribunal's home statute or one closely related to its function.

[36] In this case, I find that the applicants' appeal is not one with some prospect of success. The foundation of the applicants' submission is that their appeal raises a jurisdictional issue which is to be determined on the question of correctness. The jurisprudence, however, suggests otherwise. This case involves the interpretation by the Commission of its home statute. A decision of an administrative tribunal

interpreting or applying its home statute is to be reviewed on a reasonableness standard: *Alberta (Information and Privacy Commissioner) v. Alberta Teachers' Association*, 2011 SCC 61 at para. 39. The Supreme Court of Canada has recently reiterated this point in the context of a statutory right of appeal: *Edmonton (City) v. Edmonton East (Capilano) Shopping Centres Ltd.*, 2016 SCC 47.

[37] This case turns on the Commission's interpretation of its jurisdiction to approve a low-income rate in the absence of economic or cost of service justification. The Commission interpreted and applied the provisions of its home statute governing rate making. This lies at the core of its expertise and competence. In reaching its decision the Commission undertook a textual, contextual and purposive analysis of the key provisions. It considered the Hansard evidence tendered by each party and concluded that this extrinsic evidence reinforced its interpretation. It also extended its review to decisions of courts and tribunals from other Canadian jurisdictions and examined with care whether the relevant statutory provisions in those jurisdictions were comparable.

[38] Ultimately the Commission rejected the appellants' submissions and held that the *UCA* did not provide the Commission with the jurisdiction to approve a low-income rate in the absence of an economic or cost of service justification. In their submissions the applicants do not suggest the Commission's findings are unreasonable. They have not put forward a credible argument or basis for this Court, given the deferential standard of review, to reverse the Commission's conclusion. Given the standard of review, I have reached the conclusion that there is no prospect that this appeal can succeed.

[39] I would also note that pursuant to s. 59(4) of the *UCA*, it is a finding of fact of which the Commission is the sole judge, whether a rate is unjust, unreasonable or unduly discriminatory. The Commission in its reasons found as a fact that the low-income rates proposed by the applicants were unjust, unreasonable and unduly discriminatory and therefore not in accordance with sections 59–60 of the *UCA*. Pursuant to s. 79 of the *UCA* that finding, which goes to the heart of the applicants'

rate submissions, cannot be challenged on appeal. In the result, even if the applicants could convince this Court that the Commission's interpretation of its home statute was unreasonable the appeal would have no practical utility.

[40] The applications for leave to appeal are dismissed.

“The Honourable Mr. Justice Goepel”

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Curtailable Rates Program
54/16	April 26, 2016	Approval of the Curtailable Rate Program Reference Discount Effective April 1, 2016
45/17	April 27, 2017	Approval of the Curtailable Rate Program Reference Discount Effective April 1, 2017

Order No.	Date	General Consumer Rates
79/14	July 15, 2014	Approval for New Light Emitting Diode (LED) rates for Area and Roadway Lighting Class Effective August 1, 2014
59/16	April 28, 2016	Order in Respect of an Application by Manitoba Hydro for April 1, 2016 Interim Rates
68/16	May 17, 2016	Approval of August 1, 2016 Rate Schedules flowing from Order 59/16
80/17	July 31, 2017	Order in Respect of an Application by Manitoba Hydro for August 1, 2017 Interim Rates
85/17	August 3, 2017	Approval of August 1, 2017 Rate Schedules flowing from Order 80/17

Order No.	Date	Surplus Energy Program
43/13	April 26, 2013	Approval of Surplus Energy Program Option 1 Terms and Conditions
76/15	July 29, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
79/15	August 6, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
82/15	August 12, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
85/15	August 19, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
86/15	August 26, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/15	September 2, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
88/15	September 9, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
89/15	September 16, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
91/15	September 23, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
93/15	September 30, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
99/15	October 7, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
100/15	October 14, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
104/15	October 21, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
105/15	October 28, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
111/15	November 4, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
113/15	November 10, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
116/15	November 18, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
122/15	November 25, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
134/15	December 2, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
135/15	December 9, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
138/15	December 16, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
143/15	December 23, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
145/15	December 30, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Surplus Energy Program
2/16	January 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
6/16	January 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
10/16	January 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
13/16	January 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
19/16	February 3, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
20/16	February 10, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
22/16	February 17, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
25/16	February 24, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
29/16	March 2, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
32/16	March 9, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
35/16	March 16, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
42/16	March 23, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
44/16	March 30, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
47/16	April 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
50/16	April 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
51/16	April 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
58/16	April 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
62/16	May 4, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
66/16	May 11, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
67/16	May 18, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
69/16	May 25, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
70/16	June 1, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
73/16	June 8, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
77/16	June 15, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
80/16	June 22, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
81/16	June 29, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
82/16	July 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/16	July 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
92/16	July 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
101/16	July 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
103/16	August 3, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
109/16	August 10, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
110/16	August 17, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
112/16	August 24, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
113/16	August 31, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
116/16	September 7, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
118/16	September 14, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
119/16	September 21, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
124/16	September 28, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
126/16	October 5, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Surplus Energy Program
129/16	October 12, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
133/16	October 19, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
138/16	October 26, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
140/16	November 2, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
141/16	November 9, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
143/16	November 16, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
144/16	November 23, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
150/16	November 30, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
152/16	December 7, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
161/16	December 14, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
165/16	December 21, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
166/16	December 28, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
1/17	January 4, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
2/17	January 11, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
4/17	January 18, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
9/17	January 25, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
11/17	February 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
17/17	February 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
22/17	February 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
24/17	February 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
27/17	March 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
29/17	March 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
30/17	March 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
31/17	March 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
34/17	March 29, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
36/17	April 5, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
38/17	April 12, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
41/17	April 19, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
42/17	April 26, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
47/17	May 3, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
48/17	May 10, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
49/17	May 17, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
54/17	May 24, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
56/17	May 31, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
58/17	June 7, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
63/17	June 14, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
65/17	June 21, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
67/17	June 28, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
72/17	July 5, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
74/17	July 12, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1

Appendix 17.1 - Public Utilities Board Ex-Parte and Interim Orders

Order No.	Date	Surplus Energy Program
75/17	July 19, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
78/17	July 26, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
84/17	August 2, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/17	August 9, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
88/17	August 16, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
92/17	August 23, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
93/17	August 30, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
94/17	September 6, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
96/17	September 13, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
102/17	September 20, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
104/17	September 27, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
107/17	October 4, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
109/17	October 11, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
111/17	October 18, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
114/17	October 25, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
119/17	November 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
122/17	November 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
125/17	November 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
127/17	November 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
129/17	November 29, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
131/17	December 6, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
133/17	December 13, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
137/17	December 20, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
141/17	December 27, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
1/18	January 3, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
8/18	January 10, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
15/18	January 17, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
17/18	January 24, 2018	Approval for Surplus Energy Program Rates, Schedule SEP-1
20/18	January 31, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1