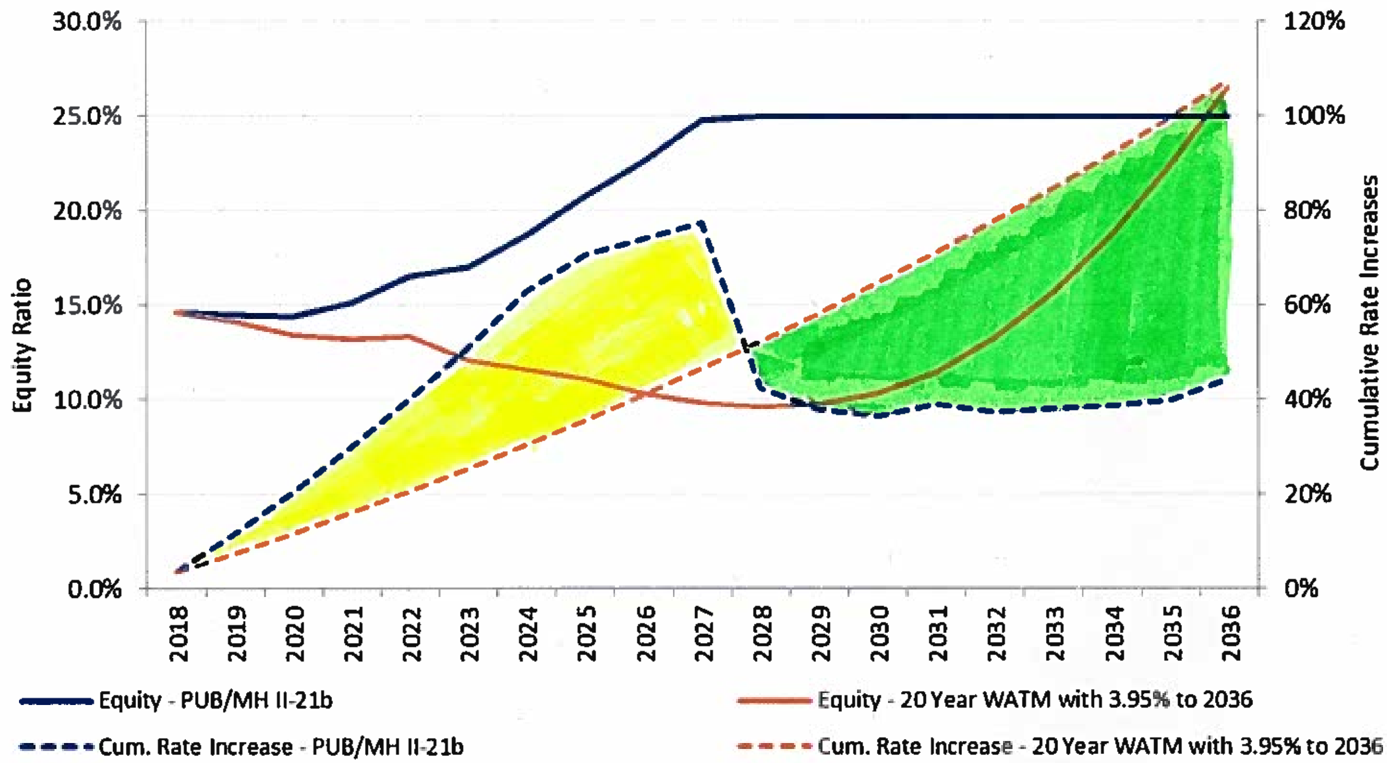
Manitoba Industrial Power Users Group Book of Documents – Volume II
Manitoba Hydro 2017/18 and 2018/19 GRA
Exhibit MIPUG-23-2

Tab #	Description	Reference
1	Ratepayer Impacts	1. MH-64, slide 30 (highlighting added) 2. LCA-13 Technical Appendix 10, NFAT Review, pg. 10A-20 – 10A-24 3. PUB-MFR-72, pages 305, 314, 406, 414, and 419 of 615
2	Cash Flow	1. Prepared Tables: Review of MH-52 Figure 1.10 Cash Flow Deficiency/Surplus & Business Operations Cap. Expenditures 2. Appendix 3.1, CEF16 MGN&T, page 51 (highlighting added) 3. Appendix 5.4 CEF16, pages 9, 17, 19, 24, 28
3	DSM	1. PUB-MFR-72, pages 215 and 280 of 615
4	Resource Economics	1. MH Exhibit # 101 in the 2012/13 and 2013/14 GRA
5	Peak Debt Comparison	1. MH-64, page 55 2. MIPUG-15, page A-6
6	Weighted Average Term to Maturity ("WATM")	1. MIPUG/MH I-20a-h 2. MH-68, page 64 3. Appendix 3.5, pages 10 – 13 4. PUB/MH II-17a-b 5. Coalition/MH I-97a-c 6. Coalition/MH I-21a-c 7. PUB/MH I-28a-c
7	Forecast Certainty	1. Appendix 7.3 pages 14 - 19
8	NFAT Transcripts re: Rate Smoothing	1. March 20, 2014 pages 3025 – 3032 (highlighting added) 2. March 21, 2014 pages 3488 – 3494 (highlighting added)
9	Equity & Debt Comparison	1. Prepared Summary Table 2. Coalition/MH II-19 (highlighting added) 3. MH-104-12-5 Plan 5, Level 2 DSM, High Keeyask financial statements pages 85 – 90 (highlighting added) 4. MH14 Financial Statements (App. 3.4 in 2015/16 GRA) (highlighting added) 5. MH15 Financial Statements (Attachment 1 in 2016/17 Interim Rate Proceeding) (highlighting added)
10	CFO to Cap. Ex	1. MIPUG/MH I-2c-f

TAB 1

Why Are We Doing This?

- Ensuring service, reliability, preparedness
- Managing risk
- Rate stability with potential for lower rates and bills in the long run



NEEDS FOR AND ALTERNATIVES TO (NFAT) REVIEW OF MANITOBA HYDRO'S PROPOSAL FOR THE KEEYASK AND CONAWAPA GENERATING STATIONS

La Capra Associates

Technical Appendix 10A

Financial Analysis Part I

PUBLIC VERSION

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January 24, 2014

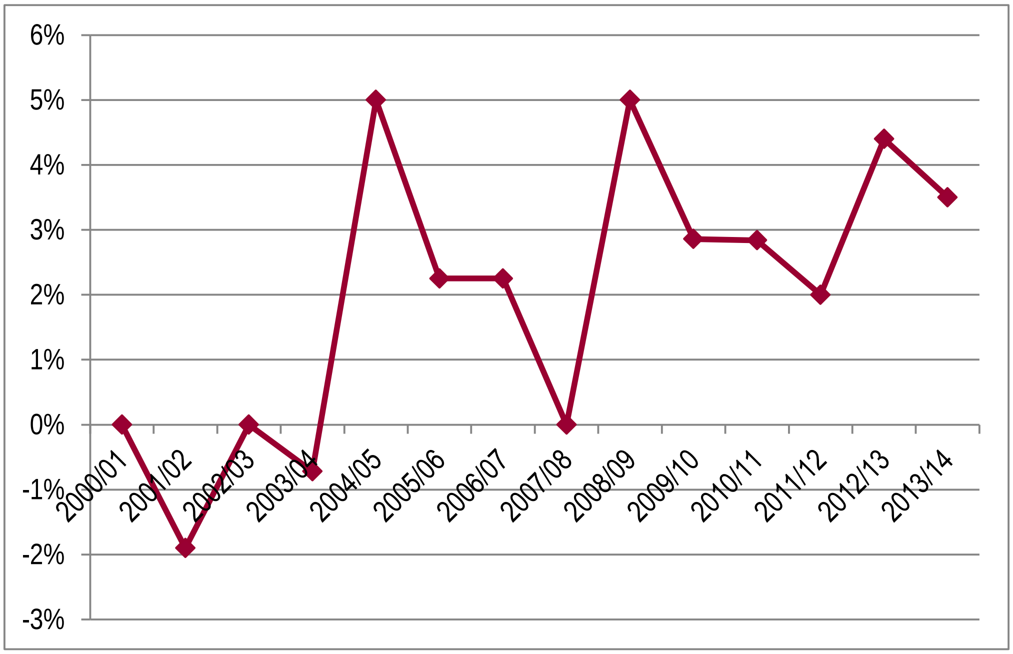


Figure 10-9. Annual Rate Increases, 2000-2013[13]

B. NPV of Rate Increases

MH did not provide estimates of (net) present value (NPV) of the additional consumer revenue increase calculated for each development plan in the NFAT filing. NPV analyses were conducted for the economic analysis of projects but were excluded in the financial analyses. MH did not explain this exclusion, but there is no obvious reason to not provide a metric that allows examination of present benefits vs. future benefits (and, for rate increases, future rate increases compared to present rate increases); rate increases impact consumption and investment decisions by consumers and businesses that undoubtedly involve considerations of present versus future net values. Thus, discounting the stream of rate increases appears to be appropriate and provides additional information that would be useful in evaluation of development plans.

Figure 10-10 provides NPV calculations for each development plan using different streams of rate increases required for each development plan (excluding revenue increases related to load growth). The calculations assume reference conditions and use of a 7.05% nominal discount rate.

[13] LCA/MH I-31.

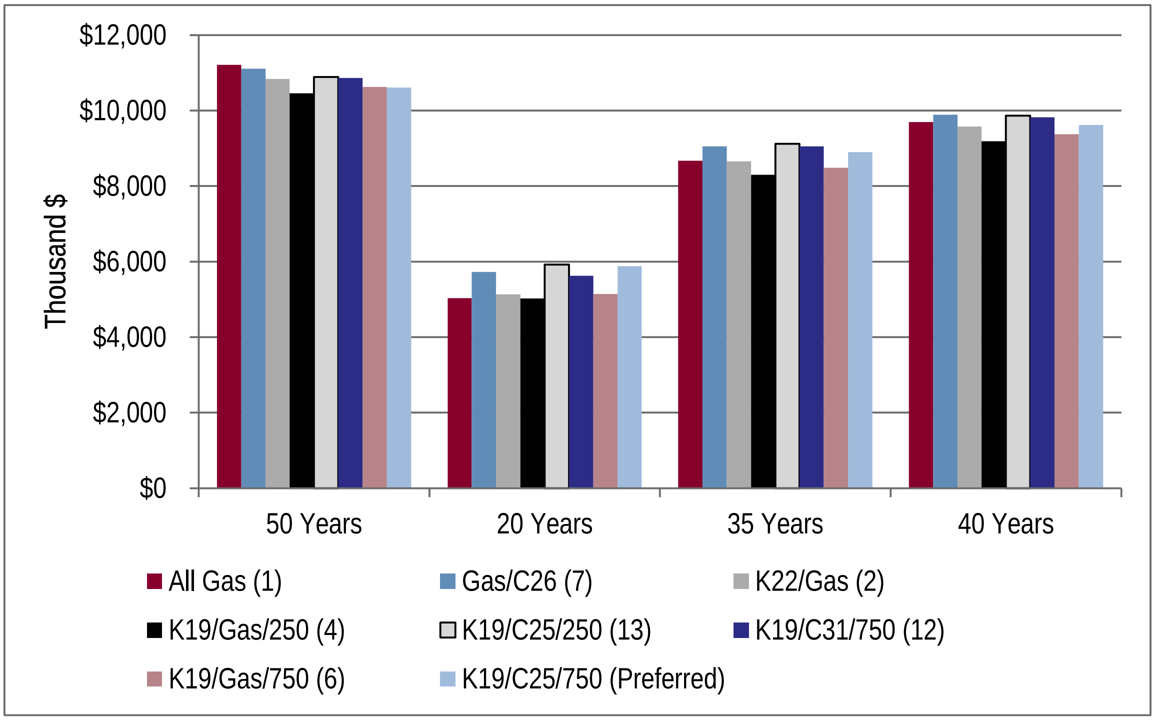


Figure 10-10. NPV of Rate Increases by Development Plan for Different Study Periods

The NPV calculations show that the Preferred plan requires higher rate increases than the K19/Gas/250 development plan assuming that the NPV is calculated over the entire study period. Indeed, the K19/Gas/250 becomes the "preferred" plan if NPV of rate increases is used as the evaluative metric, and this ranking is insensitive to the period over which the NPV is calculated (see Figure 10-11, which utilizes the data of Figure 10-10 to rank the different development plans).

Use of shorter time periods in examining the impacts on ratepayers with NPV of rate increases as a metric favors a number of development plans relative to the Preferred plan. This is not surprising given the back loaded nature of the net benefits associated with the Preferred plan (see the economic analysis discussion found in an earlier appendix). For example, over the first 20-year period, the Preferred plan has the second highest NPV of rate increases, and even over 40 years the Preferred plan only attains a middling rank when compared to the other development plans.

Nevertheless, it is important to note that the NPV results are relatively close across the development plans over the entire study period. For example, a comparison of the K19/Gas/250 and the Preferred plans, which are the two plans with the lowest NPV of rate increases over the study period, shows that that the K19/Gas/250 development is only 1.5% lower than the Preferred Plan. This aligns with the results discussion in Section III of Technical Appendix 9.

Plan (#)	50 Years	20 Years	35 Years	40 Years
All Gas (1)	8.00	2.00	4.00	5.00
Gas/C26 (7)	7.00	6.00	6.00	8.00
K22/Gas (2)	4.00	3.00	3.00	3.00
K19/Gas/250 (4)	1.00	1.00	1.00	1.00
K19/C25/250 (13)	6.00	8.00	8.00	7.00
K19/C31/750 (12)	5.00	5.00	7.00	6.00
K19/Gas/750 (6)	3.00	4.00	2.00	2.00
K19/C25/750 (Preferred)	2.00	7.00	5.00	4.00

Figure 10-11. Development Plan Ranking by Lowest Rate Increase (NPV)

The NPV calculations shown above used the "reference" nominal discount rate. MH has also provided "low" and "high" discount rates of 4.4 and 9.7%, respectively.[14] We utilize these discount rates in the discussion found in a later section of the scenario/sensitivity analysis provided in the filing.

C. Bill Impacts

The rate impact results provided by MH in their filing can be used to examine future bills paid by customers. Though it is understood that the rate trajectories analyzed in the filing do not represent actual rates to be paid by customers, we can use these projections to examine how monthly bills compare under different development plans for illustrative purposes.

[14] See response to CAC/MH-127.

We used data from a survey of Canadian electricity bills (effective May 1, 2013)[15] to establish a starting point for the bill calculations. For purposes of this appendix, we only show representative bills for a residential customer, but the findings (and relationships among developments) for other customers would be similar. Figure 10-12 shows monthly bills for different years in the study period and an NPV of monthly bills over the entire study period.

Plan (#)	2013	2032	2042	2052	2062	NPV 2012-2062
All Gas (1)	$60.96	$82.62	$115.72	$119.21	$143.32	$1,218
Gas/C26 (7)	$60.96	$85.41	$124.69	$109.96	$128.65	$1,222
K22/Gas (2)	$60.96	$83.06	$117.05	$115.46	$134.58	$1,209
K19/Gas/250 (4)	$60.96	$82.58	$115.58	$112.42	$131.55	$1,196
K19/C25/250 (13)	$60.96	$86.18	$127.28	$106.89	$120.03	$1,217
K19/C31/750 (12)	$60.96	$85.00	$123.43	$110.55	$121.69	$1,214
K19/Gas/750 (6)	$60.96	$83.06	$117.16	$112.24	$131.86	$1,202
K19/C25/750 (Preferred)	$60.96	$86.02	$126.65	$104.92	$118.28	$1,208

Figure 10-12. Monthly Bills for 750 kWh Residential Customer

Overall, the data show the significance of the anticipated rate increases from the development plans. As mentioned earlier, the development plans will require rate increases higher than those approved in recent years. By 2032, an additional $55-$66 per month is required, depending on the development plan, with increases to these amounts in future years.

The data are consistent with the observations made earlier regarding rate impacts for development plans relative to the Preferred plan (see Figure 10-6). For example, 2032 bills show that the K19/Gas/250 and All Gas plans are the development plans with the lowest bills (and rates), but by 2042 the Preferred plan shows the lowest monthly bills through the end of the study period.

The final column provides NPV calculations of the monthly bills over the entire study period using the reference discount rate. As discussed in the previous section, the

[15] Survey is available at Manitoba Hydro's website at the following link:
www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/utility_rate_comp.shtml.

K19/Gas/250 features the lowest total rate increase as measured by the 50-year NPV followed closely by the Preferred plan (see the first column in Figure 10-11). This is true despite the higher bills (when compared to the Preferred plan) in the latter part of the study period. Application of a discount rate reduces the impact of these higher bills, especially those in the later portion of the study period that are significantly discounted.

D. Summary

MH used their financial modeling framework for their entire electric operations to calculate comparative rate increases to ratepayers from the various development plans. Using the metric of even-annual and cumulative percentage increases, MH concluded that the All Gas plan had the lowest increases over the medium term (until 2031/32) but that the Preferred Plan had the lowest rate increases over the entire study period. However, use of the same results to calculate NPV of rate increase metrics showed that is not clear that the Preferred plan has the lowest rate increases over the entire study period. Moreover, the actual rates paid by domestic customers vary over time with significant increases forecasted toward the end of the study period.

The most notable issue is that all plans have significant rate increases and, as was discussed in Technical Appendix 9: Economic Analysis, the overall cost differential between plans over 78 years is very modest. The aggregate impact on rates between plans, when viewed in that 78-year perspective, is also relative modest differences between plans. However, there are important differences in the rate impact timing and risks among the alternative plans. Capital spending is much higher in the early years and natural gas prices increase over time relative to hydro-associated net costs (revenues – costs), resulting in significantly greater increases in natural gas generation costs compared to hydro costs following 2032. MH examines these changes in rates using an "even-annual" rate increase metric and a cumulative rate increase metric, which does not address the temporal issues.

Phase 2: Summary of key messages

Hydro needs to close $3.8B funding gap near-term and target 25% equity longer-term to maintain economic stability

- During capital expansion phase, must be able to service debt in downside case
- Downside case indicates $3.8B fund gap which, if left unaddressed, puts economic self sustainability at risk
- Over the longer-term Hydro should target ~25% equity comparable to Crown utilities to weather business volatility in expected case
- Expected case indicates Hydro does not achieve target equity until 2035+

5-year "workout program" developed with balanced contribution from 3 areas to close $3.8B funding gap

- Manitoba Hydro: Up to $0.8B ($275-525M in efficiency, $300M in capital project mitigation)
- Ratepayers: Up to $0.8B (Manitoba policy thresholds imply up to 9.3%/year for 5 years vs. current trajectory of 3.95%)
- Province: Can close remaining gap of $2.4B by
  - Taking DSM off balance sheet: $450M (by 2021)
  - Forgiving Provincial payments for 5 yrs – water rental, capital tax, debt guarantee – or similar capital injection: Up to $1,900M

In addition to closing $3.8B funding gap, "workout program" would accelerate meeting 25% target equity from 2035 to 2022

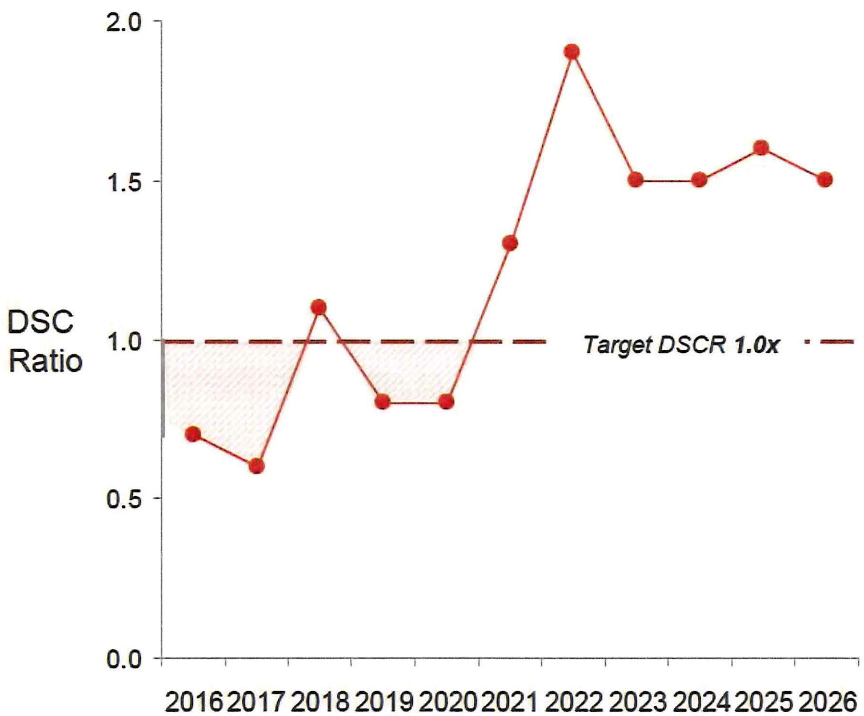
- Creates "surplus" equity position which can be used to maintain investment grade rating, issue government dividend, and/or fund future capital projects

Communication narrative needs careful articulation to instill confidence in Gov't, Board, and Mgmt to fix past mistakes

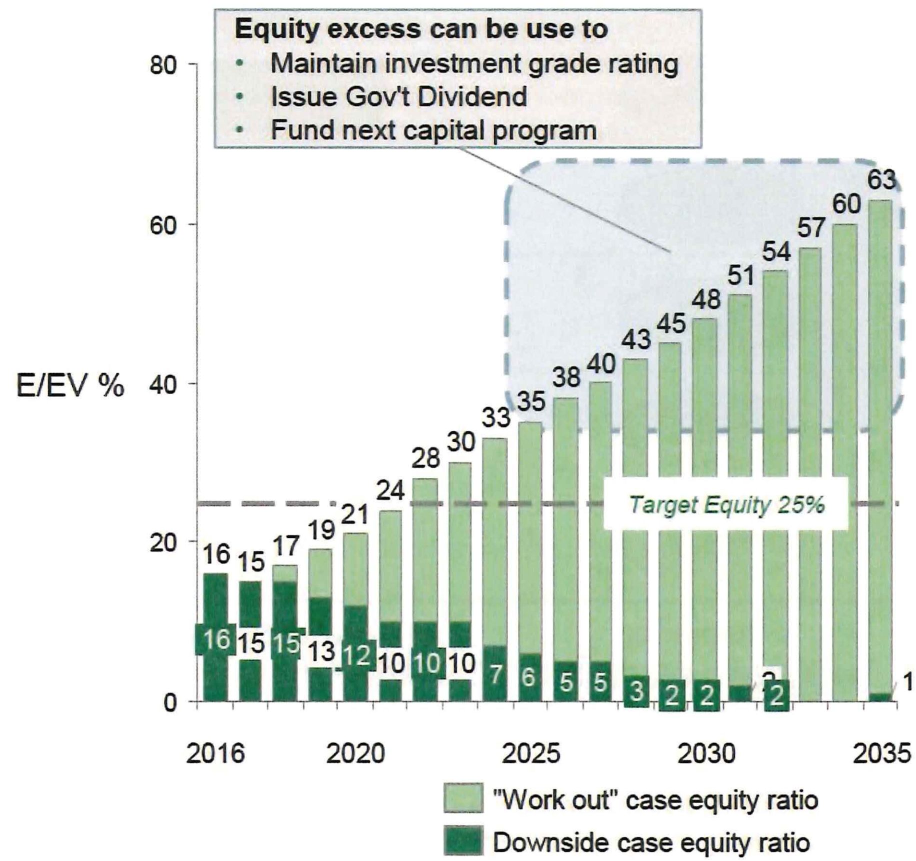
- First version of narrative required early September to avoid further delay on Bipole 3
  - Emphasis on: Deteriorated economics/timelines, decision to move forward with projects as-is, balanced workout program
- "Final" version of narrative required early October to address broader set of stakeholders and get ahead of GRA process with PUB
  - Details of workout program, implications for policy direction on rates and longer-term regulatory governance

Post-workout: DSCR and equity recover to target levels by 2022

DSCR: In downside case, gap narrowed and closed by 2020



Equity target: Met by 2022 in expected case with impact of workout plan



PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

Phase 2: Summary of key messages

Hydro needs to close $3.6B funding gap near-term and target 25% equity longer-term to maintain economic stability

- During capital expansion phase, must be able to service debt in downside case
- Downside case indicates $3.6B fund gap whi..., ... unaddres_e_, puts economic self sustainability at ri...
- Over the longer-term Hydro should target ~25% equity comparable to Crown utilities to weather business volatility in base case
- Base case indicates Hydro does not achieve target equity until 2035+

5-_ear "workout _ro_ram" develo_ed with balanced contribution from 3 areas to close $3.6B fundin_ _a_

- Manitoba Hydro: Up to $0.9B ($275-525M in efficiency, $350M in capital project mitigation)
- Ratepayers: Up to $0.8B (Manitoba policy thresholds imply up to 9.3%/year for 5 years vs. current trajectory of 3.95%)
- Province: May need to close remaining gap of $1.9B -$3B

In addition to closing $3.6B funding gap, "workout program" would accelerate meeting 25% target equity from 2035 to 2024

- Creates "surplus" equity position which can be used to maintain investment grade rating, issue government dividend and/or fund future capital projects

Communication narrative needs careful articulation to instill confidence in Gov't, Board, and Mgmt to fix past mistakes

- First version of narrative required early September to avoid further delay on Bipole 3
  - Emphasis on: Deteriorated economics/timelines, decision to move forward with projects as-is, balanced workout program
- "Final" version of narrative required early October to address broader set of stakeholders and get ahead of GRA process with PUB
  - Details of workout program, implications for policy direction on rates an_ ...g..-term regulatory governance

Master timeline required to co-ordinate multiple streams in the near and mid term

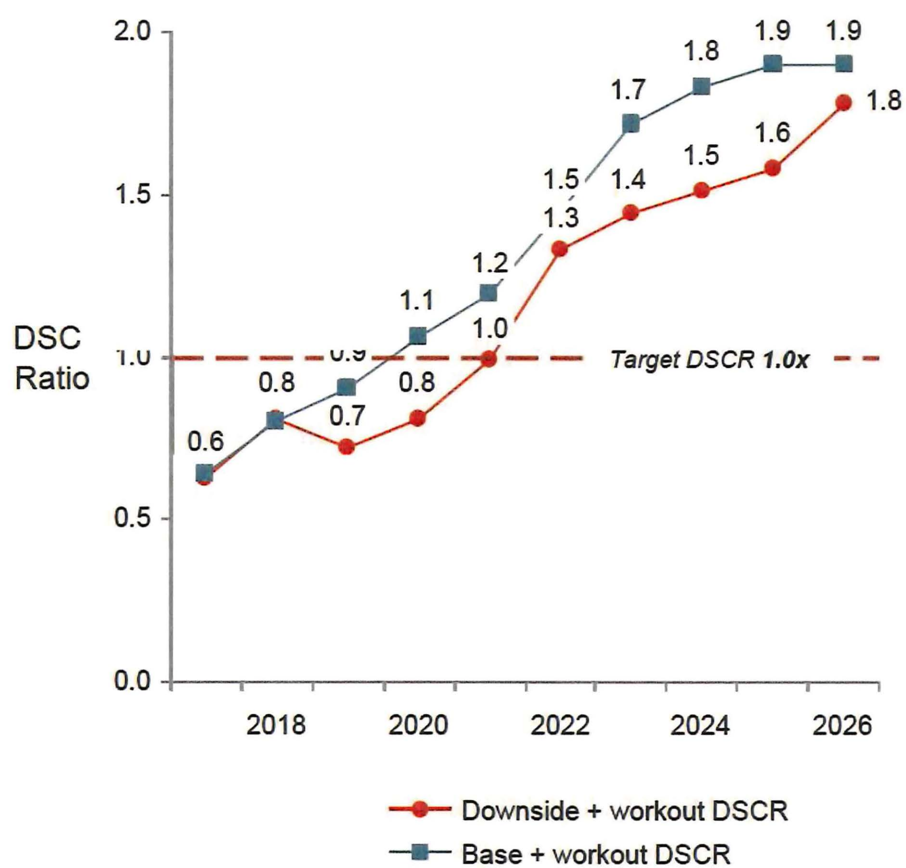
A

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

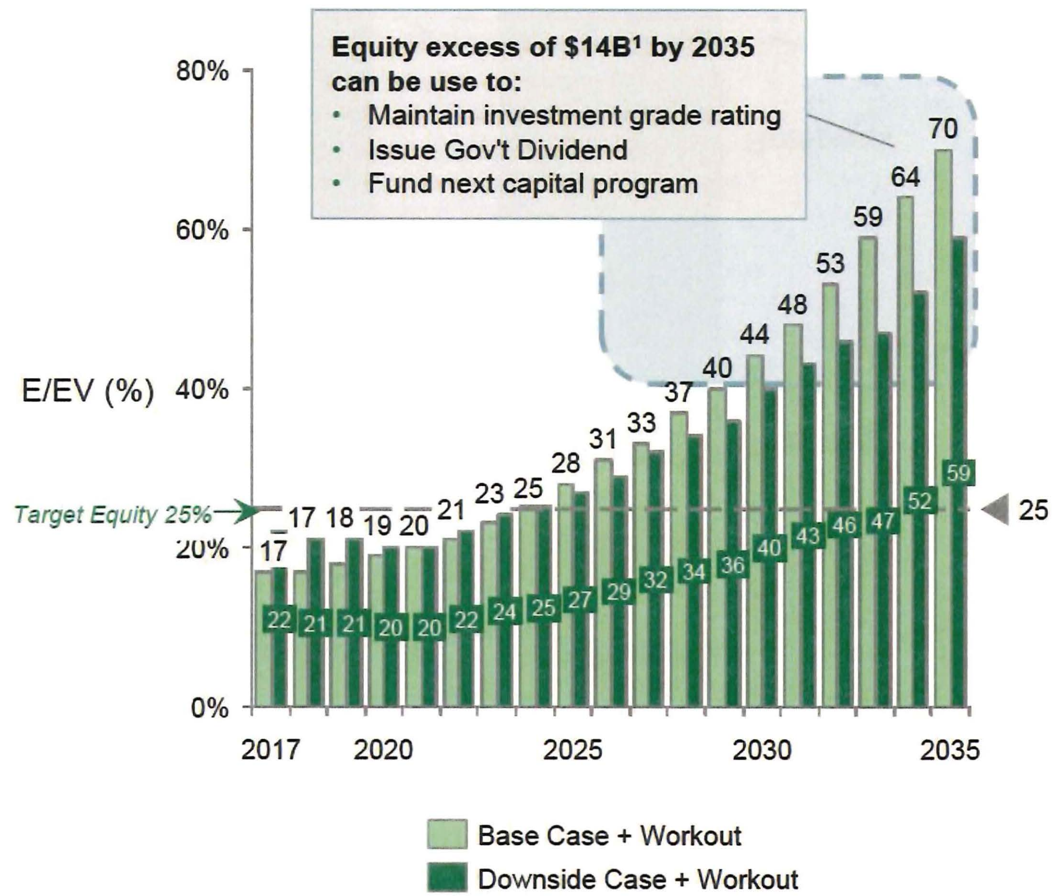
Post-workout with equity injection: Scenario A
DSCR and equity recover to target levels by 2024

9.3% Increases
High Savings

DSCR: In downside case, gap narrowed and closed by 2021



Equity target: Met by 2024 in base case with impact of workout plan



1. Versus 40% equity; Note: 5 years of rate increases beginning in FY 18; rate increases revert to 2% thereafter; Base Case equity injection of $600 M in FY '17; Downside case injection of $1.9 B
Source: Manitoba Hydro, BCG Analysis

THE BOSTON CONSULTING GROUP

Draft—for discussion only

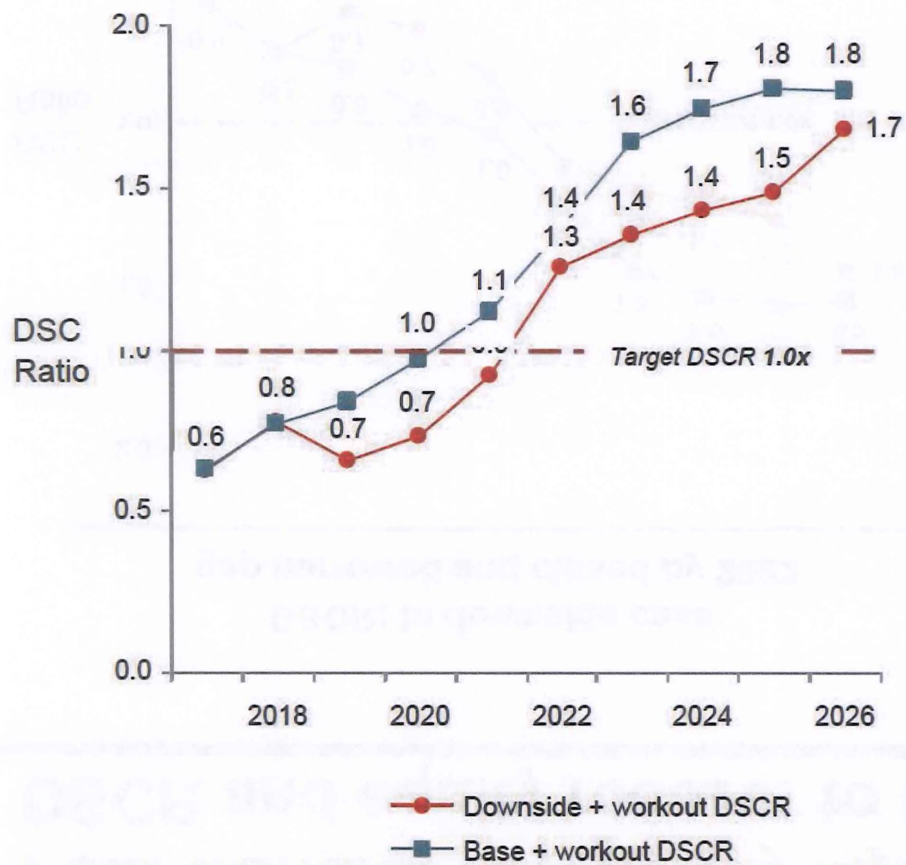
B

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

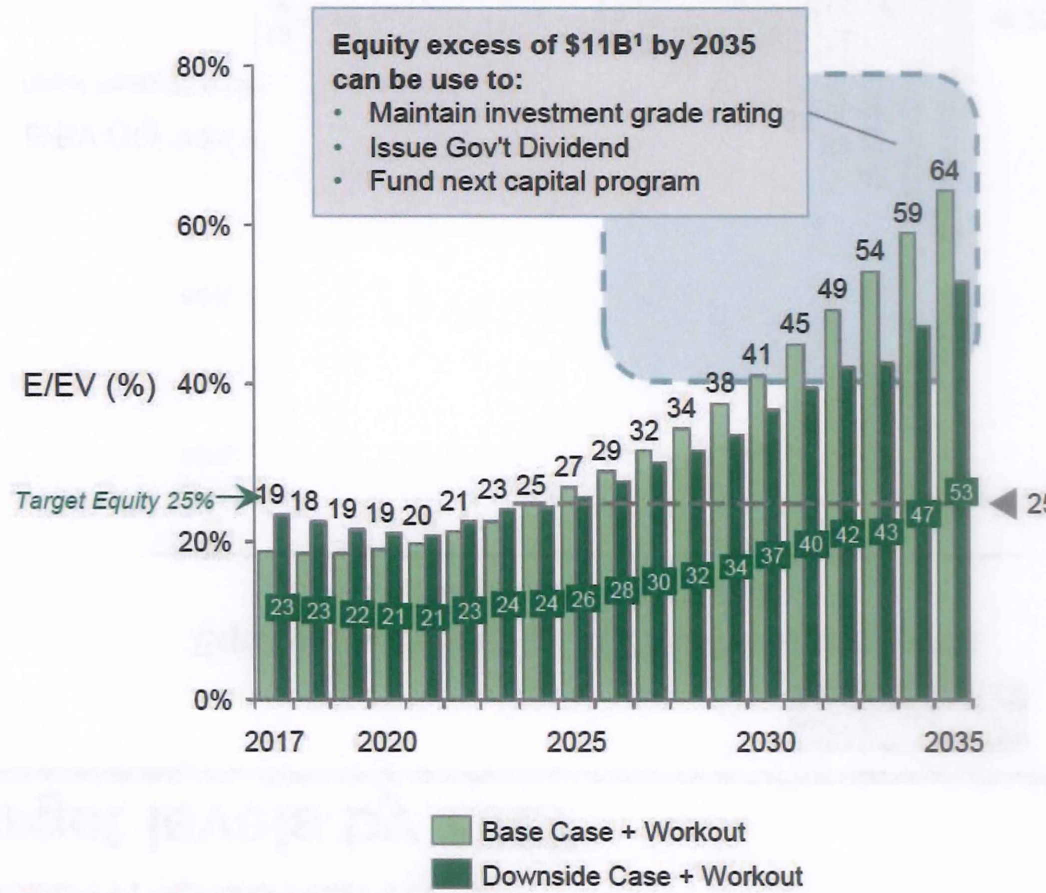
Post-workout with equity injection: Scenario B
DSCR and equity recover to target levels by 2025

9.3% Increases
Low Savings

DSCR: In downside case, gap narrowed and closed by 2021



Equity target: Met by 2025 in base case with impact of workout plan



1. Versus 40% equity; Note: 5 years of rate increases beginning in FY 18; rate increases revert to 2% thereafter; Base Case equity injection of $900 M in FY '17; Downside case injection of $2.1 B
Source: Manitoba Hydro, BCG Analysis

TAB 2

Manitoba Hydro Rebuttal (MH-52) Figure 1.10

Cash Flow (Deficiency)/Surplus (MH16 Update with Interim at MH15 rate increases and 20 year WATM)

($ Millions)	2017/18 Forecast
Receipts from Customers	2,152
Payments to Suppliers and Employees	(892)
Interest Paid	(528)
Bipole III and Other Business Operations Capitalized Interest*	(197)
Business Operations Capital Expenditures	(586)
Demand Side Management	(55)
Mitigation and Other Deferred Expenditures	(27)
Ineligible Overhead	(20)
Cash From Operations Less Capex	**(153)**
Mitigation, Major Development & Other Liability Payments	(59)
City of Winnipeg Payments	(16)
Cash Flow (Deficiency)/Surplus	**(228)**

Interest Paid (Net of All Capitalized Interest) (MH16)	
Gross Interest paid	(768)
Provincial Guarantee Fee paid	(154)
less:Intercompany Interest Receivable	15
less: Capitalized interest (Bipole III and OBO)	
Bipole III (at Weighted-Average Rates)	174
Other Business Operations	22
less: Capitalized Keeyask, MMTP & GNTL	163
Interest Received	5
Timing Difference	16
Interest Paid (Net of All Capitalized Interest)	**(528)**

Bipole III (at Weighted-Average Rates)	(174)
Other Business Operations	(22)
Total	**(197)**

Business Operations Capital Expenditures (586) → Next Page

Breakdown of Business Operations Capital Expenditures
in Manitoba Hydro Rebuttal (MH-52) Figure 1.10 for 2017/18

($ Millions)	Figure 1.10, MH-52 2017/18 Forecast	CEF16, Appendix 3.1 2017/18 Forecast	Variance
Business Operations Capital Expenditures	**586**	**608.3**	**-22.3**
Generation & Wholesale		**95.0**	
Executing Projects			**89.2**
Pine Falls Units 1-4 Major Overhauls			20.3
Great Falls Unit 4 Overhaul			0.1
Water Licenses & Renewals			8.6
Projects between $2 Million & $50 Million			60.2
Programs			**20.8**
Portfolio Adjustments			**-15**
Transmission		**131.9**	
Executing Projects			**112.9**
Lake Winnipeg East System Improvements			18.6
Letellier - St. Vital 230kV Transmission			1.5
Transmission Line Upgrades for Improved Clearance			5
Steinbach Area 230-66kV Capacity Enhance			9.4
HVDC Dorsey Synchronous Condenser Refurbishment			6.9
HVDC Transformer Replacement Program			14.4
Projects between $2 Million & $50 Million			57.1
Programs			**39.2**
Portfolio Adjustments			**-20.2**
Marketing & Customer Service		**243.1**	
Executing Projects			**117.7**
New Madison Station - 115/24kV Station			4.5
St. Vital Station 115/24kV Station			21.6
Dawson Road Station - 66/24kV			18.3
New Adelaide Station - 66/12kV			10.4
Projects between $2 Million & $50 Million			62.9
Programs			**156**
Portfolio Adjustments			**-30.6**
Human Resources & Corporate Services		**55**	
Executing Projects			**5.1**
Projects between $2 Million & $50 Million			5.1
Programs			**48.3**
Portfolio Adjustments			**1.5**
Finance & Strategy		**0.2**	
Programs			**0.2**
Unallocated Target Adjustment		**0.4**	
MNG&T Sustainment/Capital Projects		**66.1**	
Pointe du Bois Spillway Replacement			4.9
Gillam Redevelopment and Expansion Program			36.9
Kettle Improvements & Upgrades			12.6
Grand Rapids Fish Hatchery Upgrade & Expansion			11.7
Other Capital Projects		**16.7**	
Wuskwatim - Generation			5.4
Kelsey Improvements & Upgrades			7.3
Pointe du Bois - Transmission			0.1
Manitoba-Saskatchewan Transmission Project			3.9

19.0 CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)

CAPITAL EXPENDITURE & DEMAND SIDE MANAGEMENT FORECAST (CEF16)
(in millions of dollars)

	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2018-2027 10 Year Total	20 Year Total
Major New Generation & Transmission														
Executing Projects														
Keeyask - Generation	8 726.0	914.2	1 077.5	1 290.5	1 116.7	867.9	707.1	329.9	58.2	2.4	1.5	0.9	5 452.6	6 366.8
Bipole III Reliability:														
Bipole III - Transmission Line	1 957.6	477.0	511.2	345.5	9.0	1.9	-	-	-	-	-	-	867.7	1 344.6
Bipole III - Converter Stations	2 780.7	821.5	679.0	286.3	8.0	0.6	-	-	-	-	-	-	973.9	1 795.4
Bipole III - Collector Lines	246.6	55.1	36.4	24.4	-	-	-	-	-	-	-	-	60.8	116.0
Bipole III - Community Development Initiative	56.6	2.6	2.7	0.9	-	-	-	-	-	-	-	-	3.6	6.2
Bipole III Total	5 041.5	1 356.2	1 229.3	657.1	17.1	2.5	-	-	-	-	-	-	1 906.0	3 262.2
Wuskwatim - Generation	1 421.6	4.1	5.4	-	-	-	-	-	-	-	-	-	5.4	9.5
Pointe du Bois Spillway Replacement	575.7	6.8	4.9	5.7	-	-	-	-	-	-	-	-	10.6	17.4
Manitoba-Minnesota Transmission Project	453.2	7.0	86.8	114.3	82.9	146.8	-	-	-	-	-	-	430.8	437.8
Conawapa - Generation	379.8	18.3	-	-	-	-	-	-	-	-	-	-	-	18.3
Kelsey Improvements & Upgrades	336.9	3.7	7.3	9.0	-	-	-	-	-	-	-	-	16.3	20.0
Riel 230/500kV Station	319.9	1.4	-	-	-	-	-	-	-	-	-	-	-	1.4
Gillam Redevelopment and Expansion Program (GREP)	266.5	15.1	36.9	39.7	37.2	31.5	28.3	28.0	16.9	2.1	2.1	3.8	226.5	241.5
Kettle Improvements & Upgrades	112.2	18.5	12.6	1.0	-	-	-	-	-	-	-	-	13.6	32.1
Pointe du Bois - Transmission	82.4	4.1	0.1	-	-	-	-	-	-	-	-	-	0.1	4.1
Manitoba-Saskatchewan Transmission Project	56.5	3.1	3.9	2.3	18.6	17.7	10.8	-	-	-	-	-	53.3	56.4
Grand Rapids Fish Hatchery Upgrade & Expansion	23.5	2.8	11.7	6.2	1.4	-	-	-	-	-	-	-	19.2	22.1
Subtotal Executing Projects		2 355.4	2 476.2	2 125.9	1 273.9	1 066.4	746.1	357.9	75.1	4.5	3.6	4.7	8 134.3	10 489.7
Long Term Planning Investments														
Single Cycle Gas Turbines & Thermal Transmission	NA	-	-	-	-	-	-	-	-	-	-	-	-	1.6
Subtotal Planning Items		-	-	-	-	-	-	-	-	-	-	-	-	1.6
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**2 355.4**	**2 476.2**	**2 125.9**	**1 273.9**	**1 066.4**	**746.1**	**357.9**	**75.1**	**4.5**	**3.6**	**4.7**	**8 134.3**	**10 491.3**

April 2017

Capital Expenditure & Demand Side Management Forecast (CEF16)

2016/17– 2026/27

Finance & Strategy

Manitoba Hydro

Available in accessible formats upon request

Keeyask – Generation

Description:
Design and build the Keeyask generating station with seven generators and nominal capacity of 695MW on the Nelson River downstream of the Kelsey generating station. Project costs also include activities necessary to obtain approval and community support to proceed with the construction of the future generating station. These costs are comprised of extensive First Nations and other community consultations, pre-project training, joint venture business developments, environmental studies, impact statement preparations, submissions, regulatory review processes, detailed pre-engineering requirements, acquiring all necessary licensing, the design and construction of associated transmission facilities, and improvements to access roadways.

Justification:
This project increases generation for export power purposes and ultimately domestic load requirements.

In-Service Date:
First power August 2021

Revision:
The revised control budget reflects a more detailed review conducted by Manitoba Hydro. The revised control budget considers the current state of the project's progress including actual results of the first full year of concrete construction (2016) and allows for contingency to account for risks that still remain on the project. First power in-sevice date has been deferred twenty-one months from November 2019.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 6 496.1	$ 1 112.0	$ 1 226.2	$ 835.8	$ 552.6	$ 193.0	$ 140.4
Increase (Decrease)	2 230.0	(197.8)	(148.7)	454.7	564.1	674.9	959.6
Revised Forecast	$ 8 726.0	$ 914.2	$ 1 077.5	$ 1 290.5	$ 1 116.7	$ 867.9	$ 1 100.0

Kelsey Improvements & Upgrades

Description:
Overhaul and uprate all seven Kelsey generating station units including the replacement of turbine runners, bottom rings, discharge rings or weld overlays, transformers, generator windings and exciters. Perform model testing to refine runner design, perform extensive intake gate rehabilitation, perform draft tube modifications, perform an 8 000 hour inspection, and upgrade rail spur and overhead crane. Upgrade transmission facilities necessary to integrate the additional Kelsey generation into the Manitoba Hydro system network.

Justification:
Rerunnering presents the best economic solution for increasing efficiency at the Kelsey generating station and for adding system capacity without flooding or requiring a new water power license. Overhauling the units will improve the unit output by up to 11MW per unit. The transmission upgrade of a portion of the Kelsey 138 and 230kV buses and the revisions to the Northern AC Cross Trip scheme are required to accommodate the 77MW of additional Kelsey output.

In-Service Date:
December 2017

Revision:
Project decreased due to inner headcover deficiency costs lower than expected. In service date deferred thirteen months from November 2016.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 338.8	$ 12.6	$ 6.5	$ 0.2	$ -	$ -	$ -
Increase (Decrease)	(1.9)	(8.8)	0.8	8.8	-	-	-
Revised Forecast	$ 336.9	$ 3.7	$ 7.3	$ 9.0	$ -	$ -	$ -

2.1.2 Sustainment

Investments to sustain the current and future performance capability of Manitoba Hydro's generation, transmission, High Voltage Direct Current (HVDC) or distribution assets.

SUSTAINMENT ($ Millions)	2017 Outlook	2018	2019	2020	2021	2022	2018-2022 5 Year Total	2018-2027 10 Year Total	2017-2036 20 Year Total
System Renewal	29	18	7	-	-	-	24	24	55
Sustainment Total	29	18	7	-	-	-	24	24	55

2.1.2.1 System Renewal

Work performed to either replace, refurbish or remove an existing asset as the asset is approaching or is at the end of its useful life, the existing technology is approaching obsolescence, spare parts are not available, and/or the technology is/will be no longer supported. Includes repairs or replacement of assets due to damage caused by the public.

SUSTAINMENT ($ Millions)	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2018-2022 5 Year Total	2018-2027 10 Year Total	2017-2036 20 Year Total
System Renewal										
Kettle Improvements & Upgrades	112	19	13	1	-	-	-	**14**	**14**	**32**
Pointe du Bois Spillway Replacement	576	7	5	6	-	-	-	**11**	**11**	**17**
Pointe du Bois - Transmission	82	4	0	-	-	-	-	**0**	**0**	**4**
System Renewal Total		**29**	**18**	**7**	**-**	**-**	**-**	**24**	**24**	**55**

Project summaries for System Renewal executing projects are provided below:

Kettle Improvements & Upgrades

Description:
Install a new stator frame, core and winding for units 1-4. Perform rotor refurbishment, thrust runner replacement, new excitation transformers, rebabbitting of bearings, excitation upgrade replacements, control and protection system replacements, mechanical systems replacements, and intake gate and wicket gate work for units 1-4.

Justification:
The stator windings at Kettle are polyester bonded mica which is prone to internal degradation as a result of thermal and electrical stresses. There has been a much higher failure rate for stator coils at Kettle than in any of our other generators installed since 1960. Analysis of the internal conditions of the insulation system is ongoing. Unit 4 required repairs due to an incident that occurred in August 2006, where a top clamping finger on the unit broke off and fell into the air gap causing extensive damage to the windings and core. Units 1-4 have a common design deficiency in the clamping finger.

In-Service Date:
November 2017

Revision:
Estimate reflects a decrease for the cancellation of the Units 5-12 stator rewinds. A planning item was identified in the 1990's for the stator rewind of Units 5 to 12 at Kettle GS. This planning item was never formalized into a capital project and has been removed pending further study and analysis. In addition, estimates for work on units 1-3 have been reduced to reflect the awarding of mechanical contracts at a significantly lower cost and lower than expected internal resource requirements. In-service date on units 1-4 are advanced one month from December 2017.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 190.9	$ 25.8	$ 20.7	$ 30.8	$ 30.4	$ -	$ -
Increase (Decrease)	(78.7)	(7.3)	(8.1)	(29.8)	(30.4)	-	-
Revised Forecast	$ 112.2	$ 18.5	$ 12.6	$ 1.0	$ -	$ -	$ -

2.1.3 Business Operations & Support

Investments to support business operations and are shared or common throughout the corporation.

BUSINESS OPERATIONS SUPPORT ($ Millions)	2017 Outlook	2018	2019	2020	2021	2022	2018-2022 5 Year Total	2018-2027 10 Year Total	2017-2036 20 Year Total
Town site Infrastructure	15	37	40	37	31	28	174	226	242
Corporate Facilities	3	12	6	1	-	-	19	19	22
Business Operations Support Total	18	49	46	39	31	28	193	246	264

2.1.3.1 Townsite Infrastructure

Expenditures associated with community infrastructure including staff houses, housing and permanent camps. Costs for infrastructure associated with the first-time construction of a new or incremental generation, transmission, HVdc or distribution asset would typically be included with the corresponding project and not classified as Business Operations Support.

BUSINESS OPERATIONS SUPPORT ($ Millions)	Total Project Cost	2017 Outlook	2018	2019	2020	2021	2022	2018-2022 5 Year Total	2018-2027 10 Year Total	2017-2036 20 Year Total
Town Site Infrastructure										
Gillam Redevelopment & Expansion Program	266	15	37	40	37	31	28	**174**	**226**	**242**

A project summary for the Town Site Infrastructure executing project is provided below.

Gillam Redevelopment and Expansion Program (GREP)

Description:
Redevelop and expand the Town of Gillam infrastructure in Phases 1B, 2 and 3. Phases 2 & 3 will require further definition based on conceptual design and the requirement of Manitoba Hydro's construction of new facilities in the North.

Justification:
Redevelopment of the Town of Gillam is required to address existing operational needs and to prepare for the growth associated with new generation facilities. The GREP will improve the overall quality of infrastructure in Gillam, which will positively affect attraction and retention for existing and new generation facilities. The GREP supports Corporate initiatives to develop the hydroelectric potential of the Lower Nelson River.

In-Service Date:
March 2027

Revision:
Cost flow revision only.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 266.5	$ 37.7	$ 40.1	$ 27.6	$ 26.2	$ 28.7	$ 66.7
Increase (Decrease)	-	(22.7)	(3.2)	12.1	11.0	2.8	14.4
Revised Forecast	$ 266.5	$ 15.1	$ 36.9	$ 39.7	$ 37.2	$ 31.5	$ 81.1

Lake Winnipeg East System Improvements

Description:
Build a new 115/66kV Manigotagan Corner station complete with two 6OMVA transformers, a new 65km, 115kV transmission line from the Pine Falls station to the Manigotagan Corner station and the associated terminations and communications.

Justification:
The Pine Falls station currently operates over firm transformation during winter peak, which could cause customer outages in the Lake Winnipeg East area during a Pine Falls transformer outage. The outage would last greater than a week and affect more than 1,300 permanent customers and more than 13,000 seasonal (summer) customers. The new 115/66kV Manigotagan Corner station and Pine Falls – Manigotagan Corner 115kV transmission line will provide firm capacity for area load for the next 20 years, as well as enable the Bloodvein SVC to control effectively the voltage at Bloodvein, Little Grand Rapids, Beren's River and Poplar River for the next 20 years. It also reduces the loading on the Pine Falls 115/66kV station, thereby accommodating load growth in the Victoria Beach, Grand Beach and Bissett areas.

In-Service Date:
September 2017

Revision:
Increase project scope for the Pine Falls to Manigotagan Corner 115kV transmission line to increase line length by 10km, along with increased cost estimates for civil and electrical construction on the Manigotagan Corner Station, and a deferral of the in-service date by 3 months from June 2017.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 64.6	$ 26.6	$ 10.3	$ -	$ -	$ -	$ -
Increase (Decrease)	11.0	4.0	8.4	-	-	-	-
Revised Forecast	$ 75.5	$ 30.5	$ 18.6	$ -	$ -	$ -	$ -

Rockwood East 230/115kV Station

Description:
Design and construct a new 230/115kV Rockwood East station adjacent to 230kV circuits A3R (Ashern-Rosser) and S65R (Silver-Rosser) including associated equipment, protection, control and communication systems. Sectionalize and extend 230kV and 115kV transmission lines as required and provide communication and protection upgrades.

Justification:
Construction of the Rockwood East station with three 115kV line terminations would alleviate the overload scenarios for Rosser 230/115kV Banks 2 and 4 and for 115kV circuits CR4 or CR2 between Rosser and Parkdale stations. It would also increase the 115kV capacity in the Rosser/Parkdale/Selkirk area. The existing Parkdale 115/66kV station switchyard has very limited opportunity for adding new capacity due to the station's poor condition and limited space.

In-Service Date:
February 2016

Revision:
Decrease primarily due to a reduction in project contingency requirements. Additional in-service date of February 2016 added to the 230kV T/L A3R Sectionalization into Rockwood East project.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 53.2	$ 0.2	$ -	$ -	$ -	$ -	$ -
Increase (Decrease)	(3.2)	-	-	-	-	-	-
Revised Forecast	$ 50.0	$ 0.2	$ -	$ -	$ -	$ -	$ -

Pine Falls Units 1-4 Major Overhauls

Description:
Rewind Units 1-4 generators, install two (2) transformers, two (2) propeller type turbines and machine the associated water passage components. Also includes modernizing various components on Units 1 – 4 to present standards.

Justification:
Assessment of the mechanical systems has identified concerns in terms of obsolete equipment, safety, fire risk and adaptability to present day operating conditions and standards. Upgrading is necessary to ensure reliable safe and economical operation. Pine Falls consistently spills more water than the other Winnipeg River plants. Additional generation can be obtained (approximately 17%) with increased discharge capability. Tests have confirmed that the two stator windings are in danger of failure at any time.

In-Service Date:
December 2018

Revision:
Decrease due to revised interest, escalation and internal labour rates.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 90.0	$ 18.2	$ 22.0	$ 10.6	$ -	$ -	$ -
Increase (Decrease)	(1.2)	0.9	(1.7)	(0.7)	-	-	-
Revised Forecast	$ 88.8	$ 19.1	$ 20.3	$ 9.9	$ -	$ -	$ -

HVDC Dorsey Synchronous Condenser Refurbishment

Description:
Mechanical refurbishment of all nine (9) Dorsey Synchronous Condensers including stator re-wedging, refurbishment of bearings, rotor, and poles, and replacement of protection & control cubicles, Motor Control Center (MCC), excitation system and cables. Also includes replacement of the H2/CO2 ventilation and detection systems on all condensers except SC9Y, vibration monitoring, pony motor brushgear, and liquid mixing valves.

Justification:
Synchronous condensers are required for proper operation of the HVDC system, voltage regulation of the southern AC system and to provide reactive power for power export to the United States. A major inspection and overhaul of each machine is necessary to prevent catastrophic failure, involving the rotors and rotor bolts as indicated by the failures of SC12Y in 1987 and SC11Y in 1988. The cost of repairing a failure when combined with the inability to export power will well exceed the cost of major inspection and overhaul.

In-Service Date:
March 2026

Revision:
Increase due to the deferral of Pole 1 Synchronous Condenser (SC) overhauls to reflect the results of a review conducted by System Planning on the requirement of Pole 1 SCs post Riel SC in-service. Final in-service date deferred 53 months from October 2021.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 73.1	$ 7.2	$ 7.2	$ 2.3	$ 2.4	$ 2.4	$ 1.5
Increase (Decrease)	0.5	0.4	(0.2)	(1.8)	(2.4)	(2.3)	7.1
Revised Forecast	$ 73.6	$ 7.5	$ 6.9	$ 0.5	$ 0.0	$ 0.0	$ 8.6

TAB 3

Decreased DSM could improve MH financials in short-term

Executive summary

Interim findings – Aug 9

MH's DSM plan aims to allow customers reduce customer costs and delay generation

- MH Power Smart Plan identifies 41 DSM initiatives at varying levels of customer and utility cost
- Primary objectives of DSM are enabling customers to control costs and delay new generation
- DSM initiatives expected to reduce domestic gross demand by up to 10% by 2030

DSM deferral could potentially contribute to reduce financial pressure in initial years through reduced CAPEX and incremental revenue increase through higher domestic revenues

- MH's electric DSM Plan expected to require $1.2B CAPEX over 15 years
- Spot opportunity export prices are currently below domestic rates, firm prices above domestic
  - In short term reduced DSM has the potential to increase domestic revenues
  - In longer term firm contracts would likely be above domestic level given market premium

MH performed prioritization of DSM initiatives resulting in four scenarios with ~$30-65M annual CAPEX reduction and ~$11-22M annual revenue increase in the next 5 years vs. base plan

- DSM adjustment could help improving operating cash flow by up to 10% and reduce investing cash-flow by up to 5%

Three important issues identified during the assessment of DSM

- Domestic rate increase can trigger demand reduction similar to DSM given 25% customers' price sensitivity
- Setting up an off-balance sheet vehicle to fund DSM could potentially improve the perspective on financials
- Moving DSM to independent external entity financed by MH not seen as beneficial

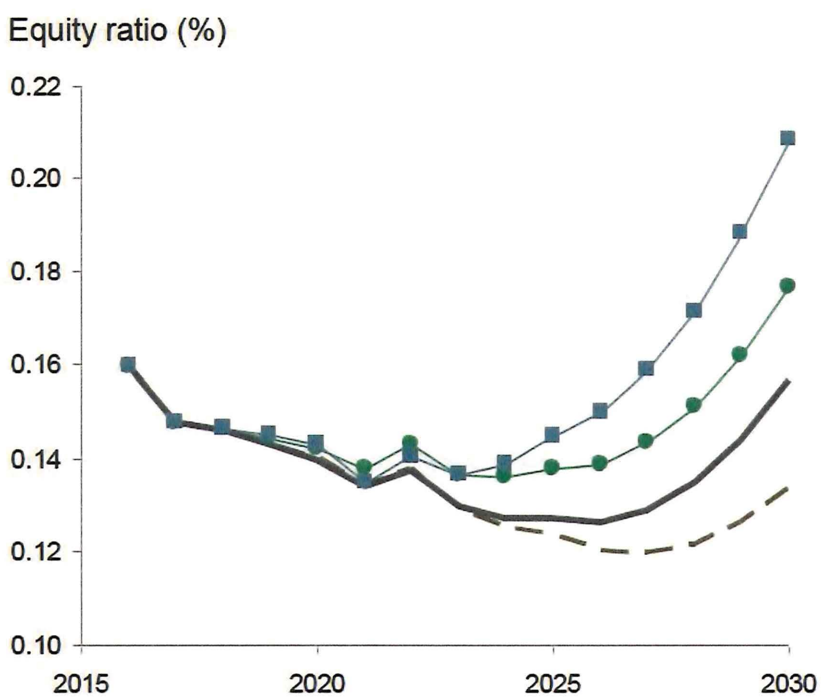
Any downward adjustment of DSM expected to have further broad risk implications

- PUB and external stakeholders anchored on the developed targets defined in the Power Smart Plan
- DSM adjustment need to be implemented with careful stakeholder- and communication actions

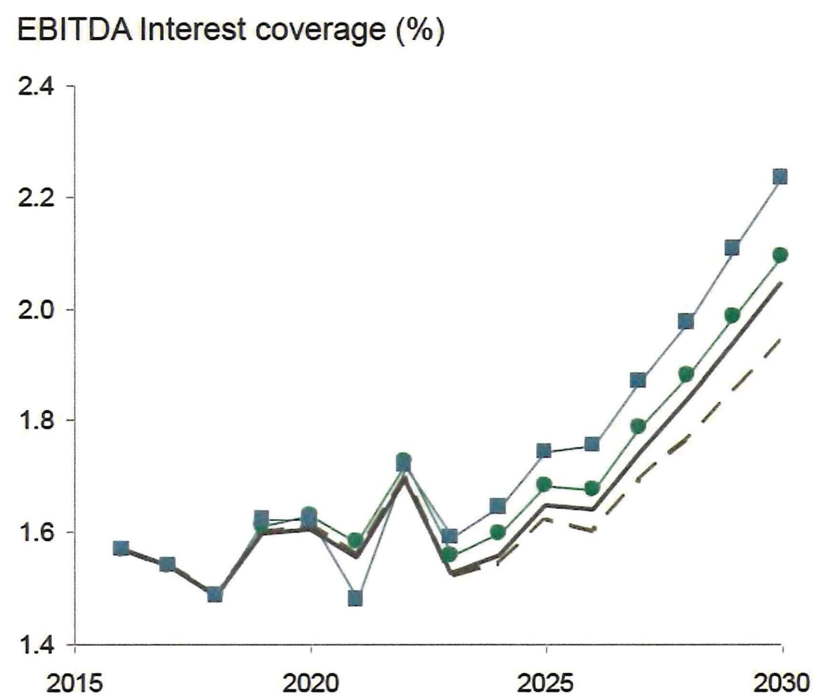
DSM adjustment could help improving key financial ratios

Preliminary

Equity ratio rebound can be accelerated



Interest coverage kept at healthier levels



Balanced — Significant ramp-down — Government 1.5% — Base

Broad risk implications need to be considered for any downward adjustment of DSM

TAB 4

MANITOBA HYDRO

2012/13 & 2013/14 ELECTRIC GENERAL RATE APPLICATION

UNDERTAKING PROVIDED BY: V. WARDEN

Manitoba Hydro Undertaking #42

Manitoba Hydro to provide the unit costs for each existing generating station on Manitoba Hydro's system. Manitoba Hydro to also indicate what discount rate was used.

Response:

The table below (column 8) provides the unit embedded cost of each generation facility by energy based on expected flow conditions ("Unit Cost"). The table reflects the mathematical derivation of Unit Cost and does not reflect the value of the resource to Manitoba Hydro. The generation costs and forecast energy output in this analysis are consistent with those in Manitoba Hydro's Prospective Cost of Service Study for 2013 ("PCOSS13") based on IFF11-2. Under other than PCOSS13 assumed flow conditions, the Unit Cost is subject to change.

The Cost of Service Study ("COSS") includes all costs included in the Corporation's Revenue Requirement which are then functionalized as Generation, Transmission, Subtransmission, and Distribution Plant or Distribution Service.

Costs functionalized as Generation in the COSS include the total costs related to generation facilities including: mitigation, HVDC Transmission facilities (excluding Dorsey convertor station), and a share of communication facilities, administrative buildings and general equipment. Costs functionalized as Generation in the COSS but unrelated to operation of the stations such as DSM, power purchases, and diesel generation have been excluded from this cost analysis. The analysis also does not include the cost of networked AC transmission or any other costs not functionalized as generation in the COSS.

The cost of the Churchill River Diversion and HVDC facilities have been included in the costs of Kettle, Limestone and Long Spruce stations, while the cost of Lake Winnipeg

Regulation has been included in the costs of all Nelson River stations (Limestone, Long Spruce, Kettle, Jenpeg, and Kelsey).

Interest costs in the COSS include the total forecast finance expense, capital taxes, and contribution to reserves which are functionalized based on net rate base investment. Therefore the study does not use a discount rate per se; however the ratio of total interest costs to net rate base in the PCOSS13 equals 5.1%.

Forecast 2012/13 Unit Costs Based on PCOSS13

	Capital Cost (million$) (1)	2012/13 GWh (2)	Water Rentals ($/MWh) (3)	O&M ($/MWh) (4)	Fuel ($/MWh) (5)	Depreciation ($/MWh) (6)	Interest ($/MWh) (7)	Total Cost ($/MWh) (8)	Total Cost ($/MWh) – Dependable Flow (9)	Total Cost ($/MWh) – Maximum Flow (10)
Limestone	1,446	7,395	3.34	4.27	-	5.85	10.50	23.97	30.53	19.07
Long Spruce	511	5,920	3.34	4.27	-	4.01	5.51	17.13	22.59	13.99
Kettle	419	6,938	3.34	3.98	-	3.46	4.97	15.75	19.97	13.16
Jenpeg	258	822	3.34	14.04	-	6.55	10.32	34.25	39.90	25.44
Kelsey	327	1,981	3.34	5.70	-	3.96	7.92	20.92	23.13	20.92
Wuskwatim	1,337	970	3.34	8.32	-	19.55	50.04	81.25	98.08*	75.11*
Great Falls	176	891	3.34	9.70	-	5.01	6.21	24.27	37.55	21.80
McArthur Falls	51	363	3.34	10.08	-	3.20	3.91	20.53	30.48	16.62
Seven Sisters	130	977	3.34	6.13	-	3.11	4.49	17.06	24.79	14.37
Pine Falls	61	647	3.34	6.82	-	2.48	3.08	15.73	26.57	14.47
Pointe Du Bois	97	432	3.34	26.41	-	11.10	7.75	48.61	64.45	36.94
Slave Falls	133	460	3.34	12.12	-	7.78	13.99	37.22	63.29	30.45
Grand Rapids	256	1,417	3.34	10.89	-	5.50	10.46	30.20	32.17	24.60
Laurie River	21	54	3.34	56.80	-	20.84	15.19	96.18	128.67	66.00
Brandon	187	56	-	261.49	35.79	160.73	85.63	543.64	75.37	543.64
Selkirk	106	20	-	494.61	44.56	124.20	129.87	793.24	79.41	793.24
Brandon CT	143	35	-	66.45	118.46	193.97	102.52	481.41	71.66	481.41
System Average								25.24	36.78	20.90

*Note Wuskwatim unit costs under dependable and maximum flows reflect partial year costs and prorated energy output.

The costs in the table represent the direct costs of owning and operating each facility divided by the megawatt hours generated in that year. These costs include both fixed and variable costs attributable to each facility such as depreciation, interest and operating costs. The cost per megawatt hour could vary substantially year over year depending on the actual output of the facility which varies depending of factors such as demand, water conditions and market prices etc. The variability is especially true for the Thermal Plants (Brandon and Selkirk) which may have very low volumes in some years as they may be uneconomic or prohibited from operating due to legislation. Unit costs have also been presented using energy production under dependable (minimum) and maximum flow conditions (columns 9 and 10) to illustrate the range in Unit Costs that are possible. The total operating and maintenance (excluding fuel and water rentals), depreciation and interest costs in these calculations are assumed to be unchanged from those in the COSS, and do not represent full year costs in the case of Wuskwatim.

The Unit Cost by Generating Station provides useful information for examining the embedded cost for each Station and may, to some extent reflect the generation vintage (in some cases old plant has been refurbished and the Unit Cost will reflect both historical and current cost).

It is, however, necessary to provide some context regarding the Unit Cost output for Hydraulic and Thermal Generating Stations as shown in the table above when compared to Export Market price data and Domestic Rates. Hydraulic and Thermal plants have different cost structures. Hydraulic generating stations have high fixed costs that accrue regardless of the amount of energy generated by the plant. The variable cost of Hydraulic Generation is low, including only Water Rental Fees and variable Operating and Maintenance costs. The variable cost of Thermal Generating Stations, on the other hand, are dominated by fuel (variable) costs that are dependent on the amount of energy generated. For the purpose of making dispatch decisions and export sales Manitoba Hydro uses the incremental variable cost of generation, which excludes fixed operating, interest and depreciation costs, and not on embedded costs as reflected in the table above. For the purpose of setting Domestic Rates Manitoba Hydro uses embedded costs (which include the cost of the Transmission and Distribution systems) offset partially by export revenue. It is therefore inappropriate to compare the Unit Costs in the table above with Export Market prices and Domestic Rates given the differences in their cost structure.

TAB 5

Debt Continues to Escalate

- Figure 5-3 from Mr. Bowman's evidence shows forecast net debt levels now substantially **exceed** high end of sensitivity range of NFAT
  - On a smaller than anticipated domestic business due to lower load growth outlook
  - Notwithstanding high water contributions of 2014/15, 2015/16, 2016/17, 2017/18 and 2018/19…
  - …and in spite of now lower interest rate forecast

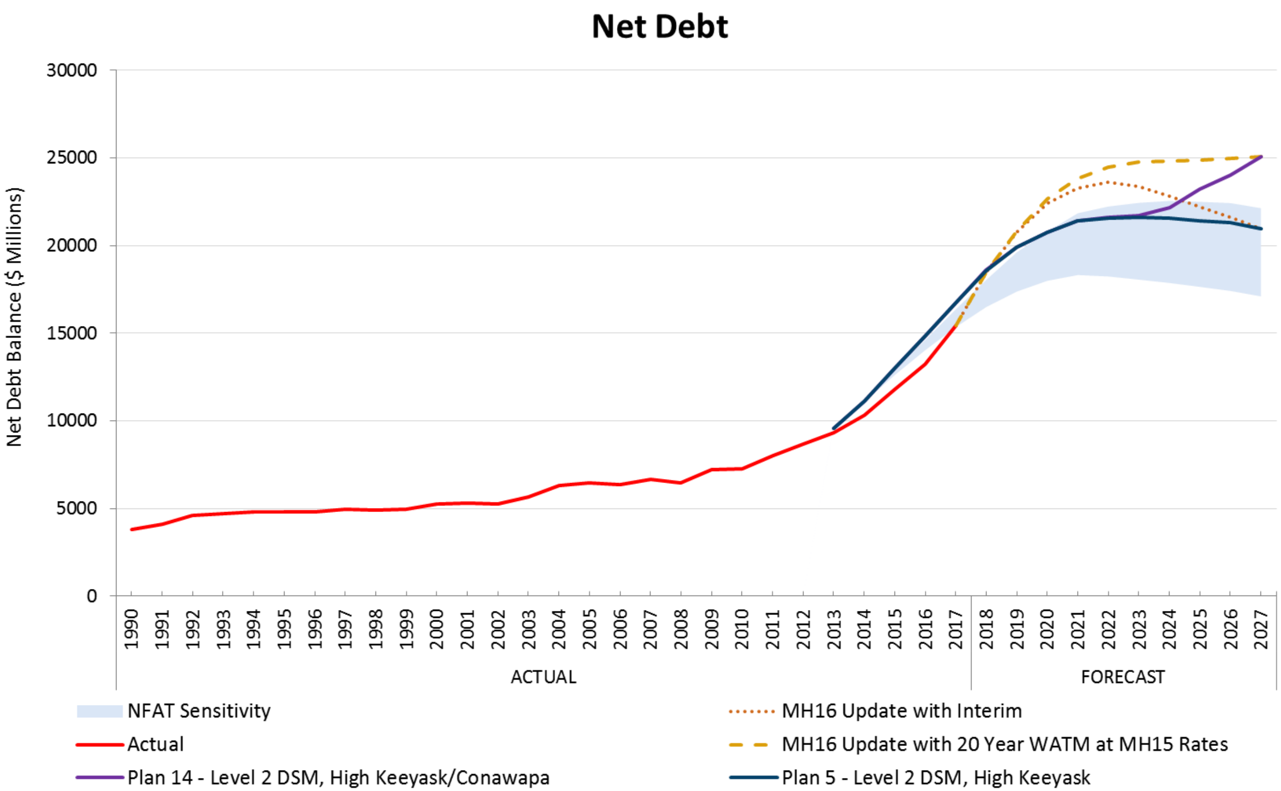
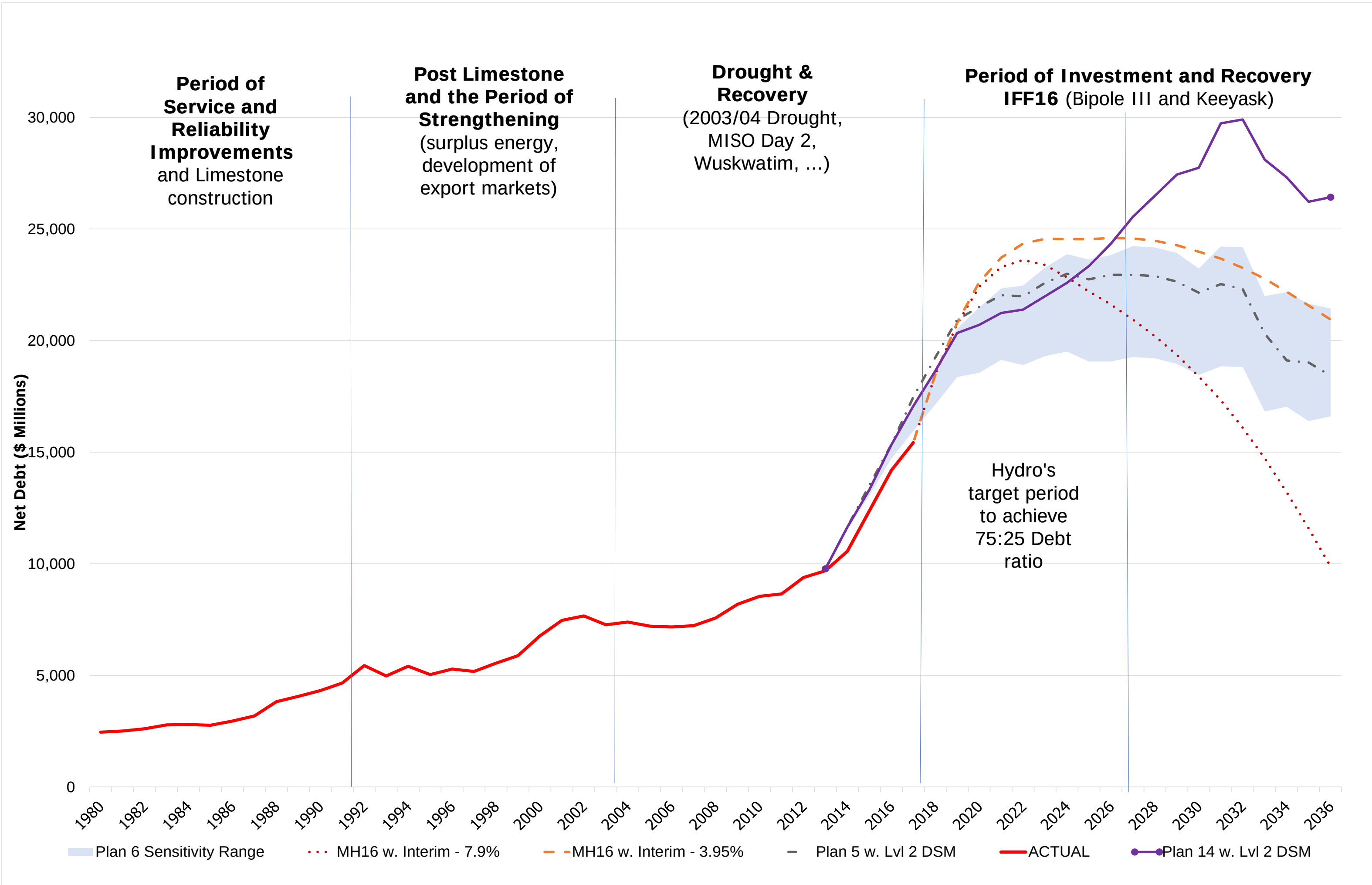


Figure A-3: Manitoba Hydro Net Debt under NFAT Scenarios and Updated IFF Scenarios at 3.95% and 7.9%[10]



[10] Plan 6 Sensitivity Range (K19/Imports/Gas/750MW) includes 27 economic sensitivity analysis scenarios provided in Appendix 11.4 spreadsheets in NFAT Review, Plan 5 (K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY) from NFAT Exhibit MH-104-12-3 update excel spreadsheets, IFF16 with Interim at 3.95% rate increases from PUB/MH I-34 Attachment 2, Actuals 1980-2017 from PUB MFR 15 and MIPUG/MH-I-2g.

TAB 6

REFERENCE:

Appendix 3.5, Page 17

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm this chart is for MH16. If not confirmed, please provide.
b) Please extend Chart 13 backwards to 1998.
c) Please provide the underlying data for the Chart (including added values for part b).
d) Please reconcile values in part (b) with Appendix 3.3, projected cash flow statement for 20 year forecast, if different.
e) Please update Chart 13 for MH16 Updated and provide underlying values.
f) Please provide a version of Chart 13 corresponding with Appendix 3.4 with annual rate increases of 3.95% and underlying values.
g) For each version of Chart 13 (MH16, Appendix 3.3 and Appendix 3.4), please specify between borrowings with maturity of under 10 years and borrowings for greater than 10 years.
    i) For borrowings with maturity under 10 years, provide a schedule that shows how much is paid off versus refinanced in each forecast year.
h) Please provide a version of Chart 13 for IFF16, also showing the underlying values, corresponding to the scenario shown in in Figure 2.5 of Tab 2 called “IFF16 Forecast 20yr Debt”.

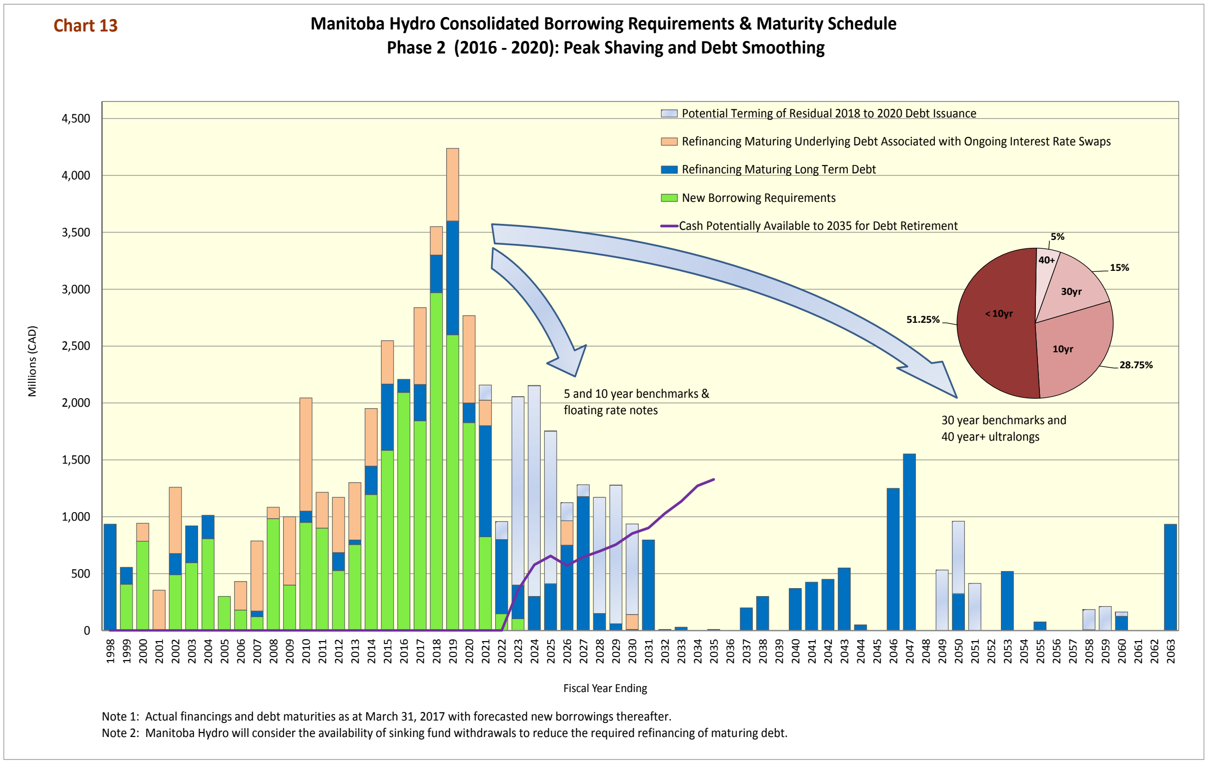
RATIONALE FOR QUESTION:

To understand Hydro’s cash flow requirements regarding future borrowing and debt management plans, and the interaction with rate increase requests

RESPONSE:

a) Confirmed, this chart is based on IFF16.

b) Please find below Chart 13 extended backwards to 1998.



c) The following table provides the underlying data for the Chart in part b).

Fiscal Year	Refinance Underlying Debt with Ongoing Swap	Refinance LTD Maturities	New Borrowings	Potential 2018-2020 Terming	Surplus Cash
1998	-	927.36	8.00	-	-
1999	-	149.10	406.08	-	-
2000	157.98	-	785.02	-	-
2001	355.00	-	0.00	-	-
2002	581.80	187.69	489.51	-	-
2003	-	328.98	591.02	-	-
2004	-	205.99	807.01	-	-
2005	-	-	300.00	-	-
2006	250.60	-	180.00	-	-
2007	616.00	50.00	121.70	-	-
2008	100.00	-	983.60	-	-
2009	600.00	-	400.00	-	-
2010	994.50	100.00	950.00	-	-
2011	315.00	-	900.00	-	-
2012	485.00	158.20	527.30	-	-
2013	504.00	41.10	755.30	-	-
2014	505.90	250.40	1,194.90	-	-
2015	381.00	583.10	1,583.50	-	-
2016	-	115.48	2,092.74	-	-
2017	675.76	319.51	1,843.29	-	-
2018	250.00	330.41	2,969.59	-	-
2019	638.00	1,000.67	2,599.33	-	-
2020	767.50	172.84	1,827.16	-	-
2021	225.00	975.41	824.59	133.13	-
2022	-	653.13	146.87	158.93	-
2023	-	296.36	103.65	1,656.91	356.00
2024	-	300.00	-	1,854.13	578.00
2025	-	411.64	-	1,343.91	656.00
2026	215.00	750.00	-	158.93	571.00
2027	-	1,177.84	-	103.78	646.00
2028	-	150.00	-	1,020.63	696.71
2029	-	60.00	-	1,218.43	755.19
2030	131.00	10.00	-	795.66	852.97
2031	-	795.76	-	-	901.97
2032	-	9.95	-	-	1,028.78
2033	-	30.00	-	-	1,134.24
2034	-	-	-	-	1,272.14
2035	-	10.00	-	-	1,328.10
2036	-	-	-	-	-
2037	-	200.00	-	-	-
2038	-	300.00	-	-	-
2039	-	-	-	-	-
2040	-	368.60	-	-	-
2041	-	425.00	-	-	-
2042	-	450.00	-	-	-
2043	-	550.00	-	-	-
2044	-	50.00	-	-	-
2045	-	-	-	-	-
2046	-	1,250.00	-	-	-
2047	-	1,552.13	-	-	-
2048	-	-	-	-	-
2049	-	-	-	532.50	-
2050	-	325.00	-	635.70	-
2051	-	-	-	415.13	-
2052	-	-	-	-	-
2053	-	520.00	-	-	-
2054	-	-	-	-	-
2055	-	75.00	-	-	-
2056	-	-	-	-	-
2057	-	-	-	-	-
2058	-	7.04	-	177.50	-
2059	-	-	-	211.90	-
2060	-	125.00	-	38.38	-
2061	-	-	-	-	-
2062	-	-	-	-	-
2063	-	934.00	-	-	-

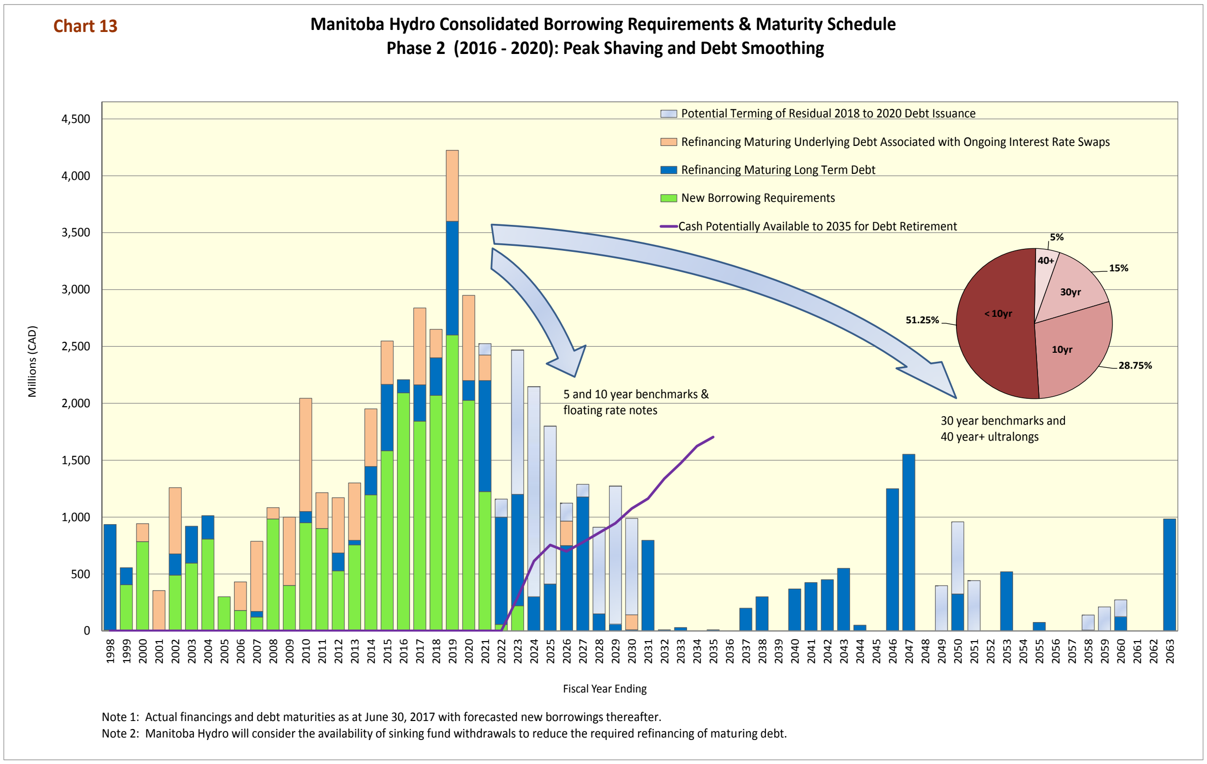
d) Chart 13 in part b) portrays Manitoba Hydro's existing debt maturity schedule at March 31, 2017 based on requirements for actual physical debt issuance ('action date' basis) which include the refinancing of underlying debt attached to an ongoing interest rate swap. The IFF16 assumes that these debt streams mature and will be refinanced at the swap maturity date, therefore the forecasting model does not generate additional borrowings for these refinancings on the cash flow statement (and subsequently does not show the debt retirement either). However, the corporation will have to secure the funds to refinance the underlying maturing debt, therefore it is added in Chart 13 showing the total financing requirements. As such, the total financings in Chart 13 will be different in certain years from 'Proceeds from Long Term Debt' on the cash flow statement. Similarly, in Chart 13 the 'Refinancing Maturing Long Term Debt' will be different from the 'Retirement of Long Term Debt' on the cash flow statement.

As mentioned above, Chart 13 in part b) portrays Manitoba Hydro's existing debt maturity schedule at March 31, 2017 as well as the potential terming of the 2018-2020 debt issuance into the planned new weightings in various terms. The IFF16 cash flow statement reflects the maturity of the debt issued in 2018 in the year 2030 (and in a similar fashion after 12 years for 2019 and beyond) due to the simplifying assumption of a 12 year term to maturity in the forecasting model.

In addition, USD debt maturities in Chart 13 in part b) are translated at the foreign exchange (FX) rate at March 31, 2017, whereas the IFF16 cash flow statement utilizes the forecast FX rate for the given year to translate USD maturities into CAD dollars.

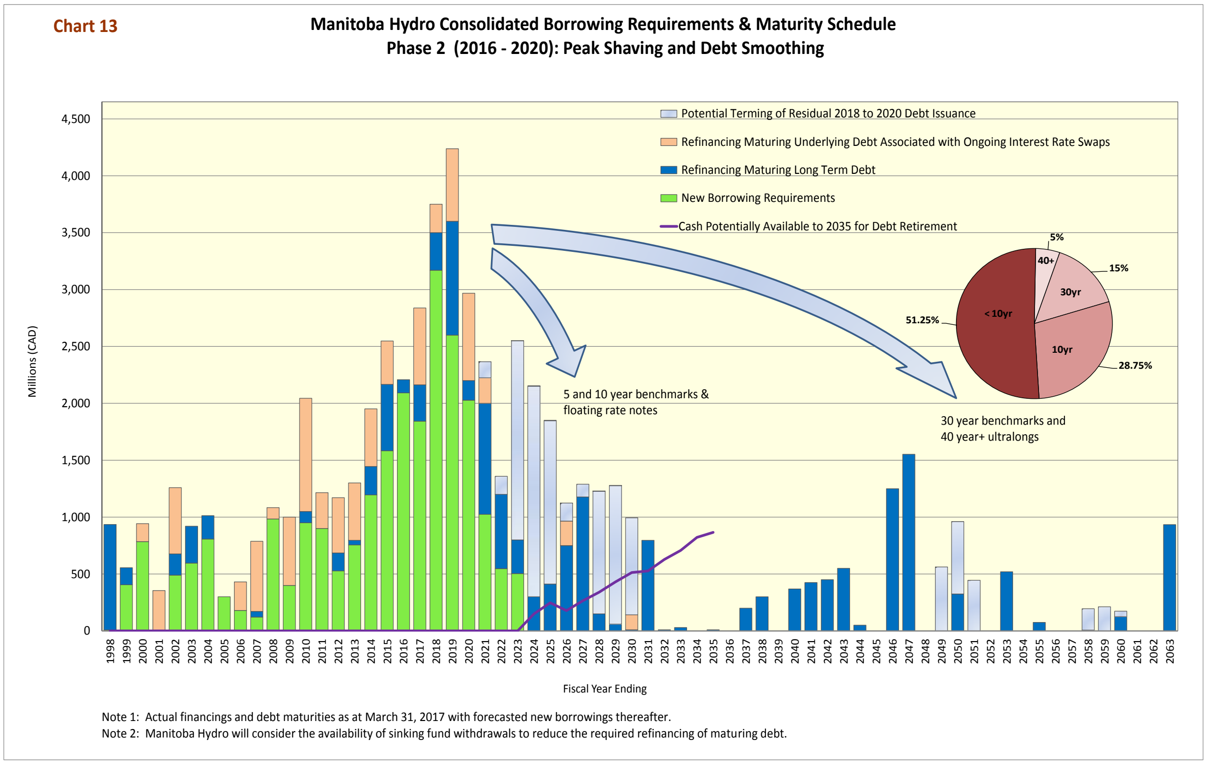
The 'Cash Potentially Available for Debt Retirement' in Chart 13 is calculated as Cash Flow from Operations less investment in Property, Plant & Equipment from the cash flow statement.

e) Please find below Chart 13 based on MH16 Update with Interim and a table including the underlying values.



Fiscal Year	Refinance Underlying Debt with Ongoing Swap	Refinance LTD Maturities	New Borrowings	Potential 2018-2020 Terming	Surplus Cash
1998	-	927.36	8.00	-	-
1999	-	149.10	406.08	-	-
2000	157.98	-	785.02	-	-
2001	355.00	-	-	-	-
2002	581.80	187.69	489.51	-	-
2003	-	328.98	591.02	-	-
2004	-	205.99	807.01	-	-
2005	-	-	300.00	-	-
2006	250.60	-	180.00	-	-
2007	616.00	50.00	121.70	-	-
2008	100.00	-	983.60	-	-
2009	600.00	-	400.00	-	-
2010	994.50	100.00	950.00	-	-
2011	315.00	-	900.00	-	-
2012	485.00	158.20	527.30	-	-
2013	504.00	41.10	755.30	-	-
2014	505.90	250.40	1,194.90	-	-
2015	381.00	583.10	1,583.50	-	-
2016	0.00	115.48	2,092.74	-	-
2017	675.76	319.51	1,843.29	-	-
2018	250.00	330.41	2,069.59	-	-
2019	623.82	999.55	2,600.45	-	-
2020	748.85	174.24	2,025.76	-	-
2021	225.00	975.41	1,224.59	99.38	-
2022	-	942.78	57.22	158.39	-
2023	-	979.71	220.30	1,269.96	294.35
2024	-	300.00	-	1,847.92	613.50
2025	-	411.64	-	1,389.50	754.92
2026	215.00	750.00	-	158.39	699.00
2027	-	1,177.84	-	110.58	779.04
2028	-	150.00	-	761.88	862.43
2029	-	60.00	-	1,214.35	946.12
2030	131.00	10.00	-	847.79	1,075.39
2031	-	795.76	-	-	1,162.70
2032	-	10.09	-	-	1,337.32
2033	-	30.00	-	-	1,473.68
2034	-	-	-	-	1,624.27
2035	-	10.00	-	-	1,703.73
2036	-	-	-	-	-
2037	-	200.00	-	-	-
2038	-	300.00	-	-	-
2039	-	-	-	-	-
2040	-	368.60	-	-	-
2041	-	425.00	-	-	-
2042	-	450.00	-	-	-
2043	-	550.00	-	-	-
2044	-	50.00	-	-	-
2045	-	-	-	-	-
2046	-	1,250.00	-	-	-
2047	-	1,552.13	-	-	-
2048	-	-	-	-	-
2049	-	-	-	397.50	-
2050	-	325.00	-	633.57	-
2051	-	-	-	442.33	-
2052	-	-	-	-	-
2053	-	520.00	-	-	-
2054	-	-	-	-	-
2055	-	75.00	-	-	-
2056	-	-	-	-	-
2057	-	-	-	-	-
2058	-	7.04	-	132.50	-
2059	-	-	-	211.19	-
2060	-	125.00	-	147.44	-
2061	-	-	-	-	-
2062	-	-	-	-	-
2063	-	984.00	-	-	-

f) Please see Chart 13 below based on IFF16 with 3.95% rate increases and a table including the underlying values:

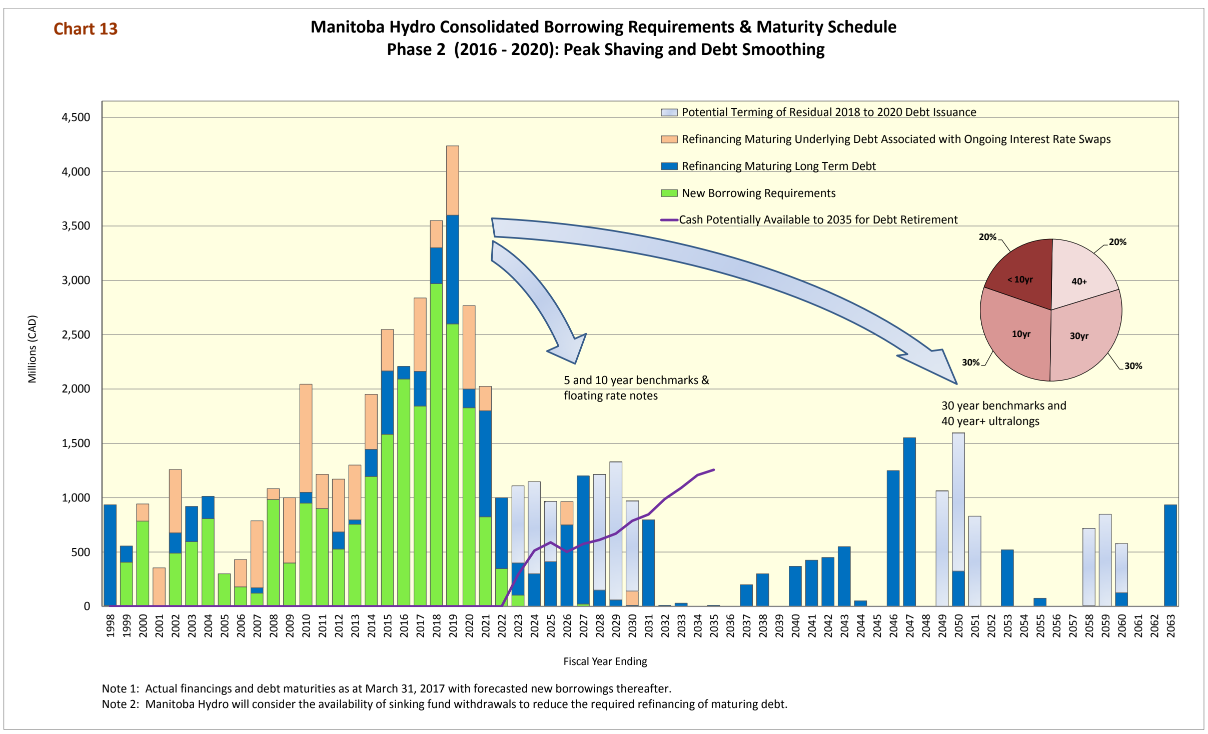


Fiscal Year	Refinance Underlying Debt with Ongoing Swap	Refinance LTD Maturities	New Borrowings	Potential 2018-2020 Terming	Surplus Cash
1998	-	927.36	8.00	-	-
1999	-	149.10	406.08	-	-
2000	157.98	-	785.02	-	-
2001	355.00	-	0.00	-	-
2002	581.80	187.69	489.51	-	-
2003	-	328.98	591.02	-	-
2004	-	205.99	807.01	-	-
2005	-	-	300.00	-	-
2006	250.60	-	180.00	-	-
2007	616.00	50.00	121.70	-	-
2008	100.00	-	983.60	-	-
2009	600.00	-	400.00	-	-
2010	994.50	100.00	950.00	-	-
2011	315.00	-	900.00	-	-
2012	485.00	158.20	527.30	-	-
2013	504.00	41.10	755.30	-	-
2014	505.90	250.40	1,194.90	-	-
2015	381.00	583.10	1,583.50	-	-
2016	-	115.48	2,092.74	-	-
2017	675.76	319.51	1,843.29	-	-
2018	250.00	330.41	3,169.59	-	-
2019	638.00	1,000.67	2,599.33	-	-
2020	767.50	172.84	2,027.16	-	-
2021	225.00	975.41	1,024.59	140.63	-
2022	-	653.13	546.87	158.93	-
2023	-	296.36	503.65	1,751.91	-
2024	-	300.00	-	1,854.13	149.65
2025	-	411.64	-	1,438.91	247.40
2026	215.00	750.00	-	158.93	178.65
2027	-	1,177.84	-	111.28	265.29
2028	-	150.00	-	1,078.13	339.95
2029	-	60.00	-	1,218.43	430.27
2030	131.00	10.00	-	853.16	512.62
2031	-	795.76	-	-	527.40
2032	-	9.95	-	-	627.80
2033	-	30.00	-	-	707.42
2034	-	-	-	-	821.59
2035	-	10.00	-	-	866.45
2036	-	-	-	-	-
2037	-	200.00	-	-	-
2038	-	300.00	-	-	-
2039	-	-	-	-	-
2040	-	368.60	-	-	-
2041	-	425.00	-	-	-
2042	-	450.00	-	-	-
2043	-	550.00	-	-	-
2044	-	50.00	-	-	-
2045	-	-	-	-	-
2046	-	1,250.00	-	-	-
2047	-	1,552.13	-	-	-
2048	-	-	-	-	-
2049	-	-	-	562.50	-
2050	-	325.00	-	635.70	-
2051	-	-	-	445.13	-
2052	-	-	-	-	-
2053	-	520.00	-	-	-
2054	-	-	-	-	-
2055	-	75.00	-	-	-
2056	-	-	-	-	-
2057	-	-	-	-	-
2058	-	7.04	-	187.50	-
2059	-	-	-	211.90	-
2060	-	125.00	-	48.38	-
2061	-	-	-	-	-
2062	-	-	-	-	-
2063	-	934.00	-	-	-

g) In each version of Chart 13, the short light blue arrow points to the potential terming of 2018 to 2020 debt issuance with terms of 10 years or less, and the longer light blue arrow points to the potential terming of debt issuance greater than 10 years.

In each version of Chart 13, 'Cash Potentially Available for Debt Retirement' is represented by the line graph. In each scenario, should all forecast assumptions hold (rate increases, cost savings, export prices, interest rate forecasts, in-service dates) this surplus cash could be available to retire debt or be used for other purposes. Any amount of cash made available for debt retirement would repay an equivalent amount of debt maturities which would otherwise need to be refinanced.

h) Please see the Chart 13 below based on IFF16 20 year debt and a table including the underlying data:



Fiscal Year	Refinance Underlying Debt with Ongoing Swap	Refinance LTD Maturities	New Borrowings	Potential 2018-2020 Terming	Surplus Cash
1998	-	927.36	8.00	-	-
1999	-	149.10	406.08	-	-
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2001	355.00	-	-	-	-
2002	581.80	187.69	489.51	-	-
2003	-	328.98	591.02	-	-
2004	-	205.99	807.01	-	-
2005	-	-	300.00	-	-
2006	250.60	-	180.00	-	-
2007	616.00	50.00	121.70	-	-
2008	100.00		983.60	-	-
2009	600.00		400.00	-	-
2010	994.50	100.00	950.00	-	-
2011	315.00		900.00	-	-
2012	485.00	158.20	527.30	-	-
2013	504.00	41.10	755.30	-	-
2014	505.90	250.40	1,194.90	-	-
2015	381.00	583.10	1,583.50	-	-
2016	-	115.48	2,092.74	-	-
2017	675.76	319.51	1,843.29	-	-
2018	250.00	330.41	2,969.59	-	-
2019	638.00	1,000.67	2,599.33	-	-
2020	767.50	172.84	1,827.16	-	-
2021	225.00	975.41	824.59	-	-
2022	-	653.13	346.87	-	-
2023	-	296.36	103.65	710.00	291.00
2024	-	300.00	-	847.60	513.00
2025	-	411.64	-	553.50	589.00
2026	215.00	750.00	-	-	502.00
2027	-	1,177.84	22.16	-	575.00
2028	-	150.00	-	1,065.00	612.71
2029	-	60.00	-	1,271.40	670.19
2030	131.00	10.00	-	830.25	786.97
2031	-	795.76	-	-	845.97
2032	-	9.95	-	-	987.78
2033	-	30.00	-	-	1,090.24
2034	-	-	-	-	1,208.14
2035	-	10.00	-	-	1,257.10
2036	-	-	-	-	-
2037	-	200.00	-	-	-
2038	-	300.00	-	-	-
2039	-	-	-	-	-
2040	-	368.60	-	-	-
2041	-	425.00	-	-	-
2042	-	450.00	-	-	-
2043	-	550.00	-	-	-
2044	-	50.00	-	-	-
2045	-	-	-	-	-
2046	-	1,250.00	-	-	-
2047	-	1,552.13	-	-	-
2048	-	-	-	-	-
2049	-	-	-	1,065.00	-
2050	-	325.00	-	1,271.40	-
2051	-	-	-	830.25	-
2052	-	-	-	-	-
2053	-	520.00	-	-	-
2054	-	-	-	-	-
2055	-	75.00	-	-	-
2056	-	-	-	-	-
2057	-	-	-	-	-
2058	-	7.04	-	710.00	-
2059	-	-	-	847.60	-
2060	-	125.00	-	453.50	-
2061	-	-	-	-	-
2062	-	-	-	-	-
2063	-	934.00	-	-	-

Manitoba Hydro

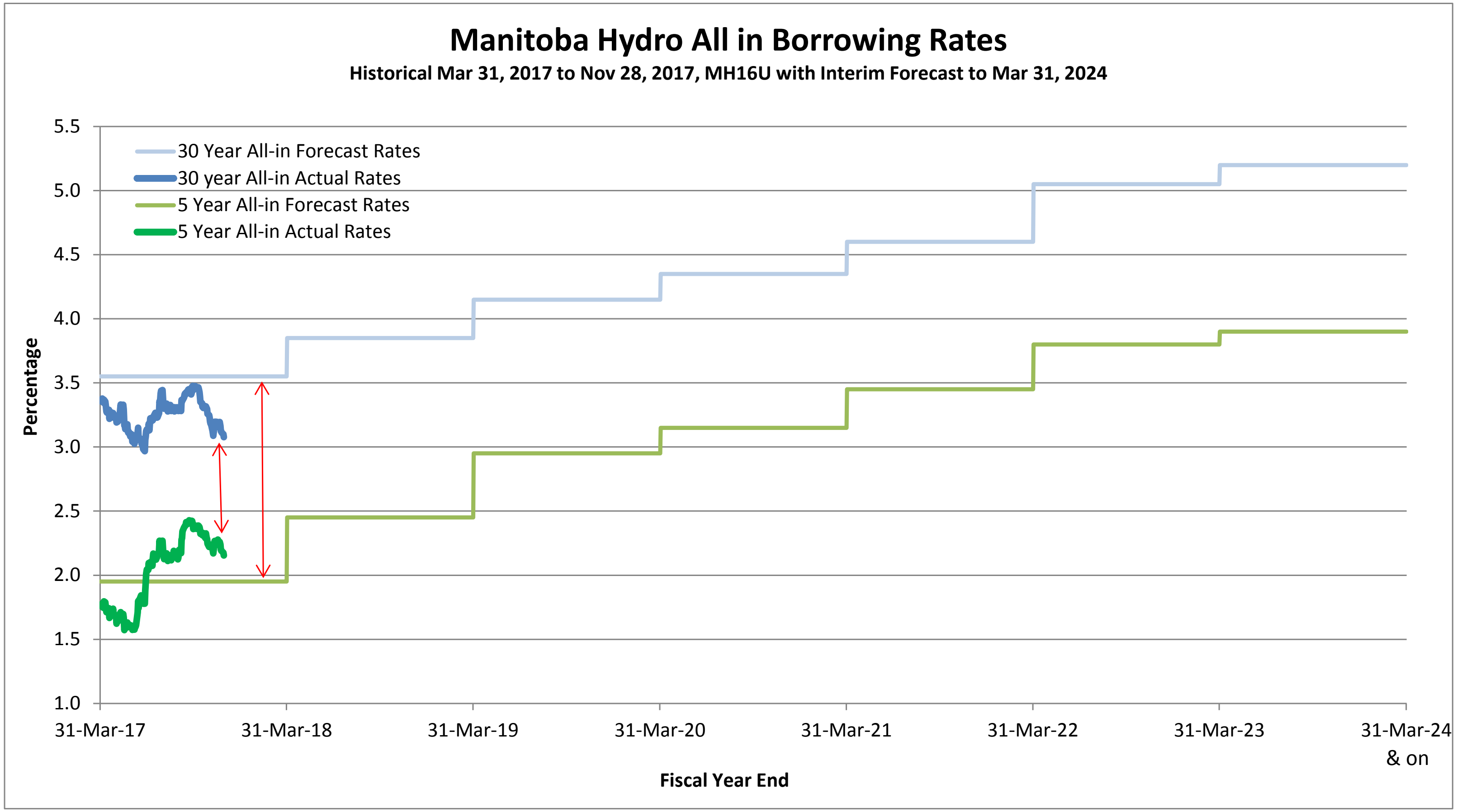
2017/18 & 2018/19

Electric General Rate Application

December 6, 2017

Revenue Requirement Panel

Interest Rate Risk



- Currently, there is approximately 0.9% differential between all-in borrowing cost for 5 and 30 year Manitoba Hydro debt.
- Forecast of $500 million benefit from adjusted WATM reduced to under $250 million as a result of changes to the yield curve.

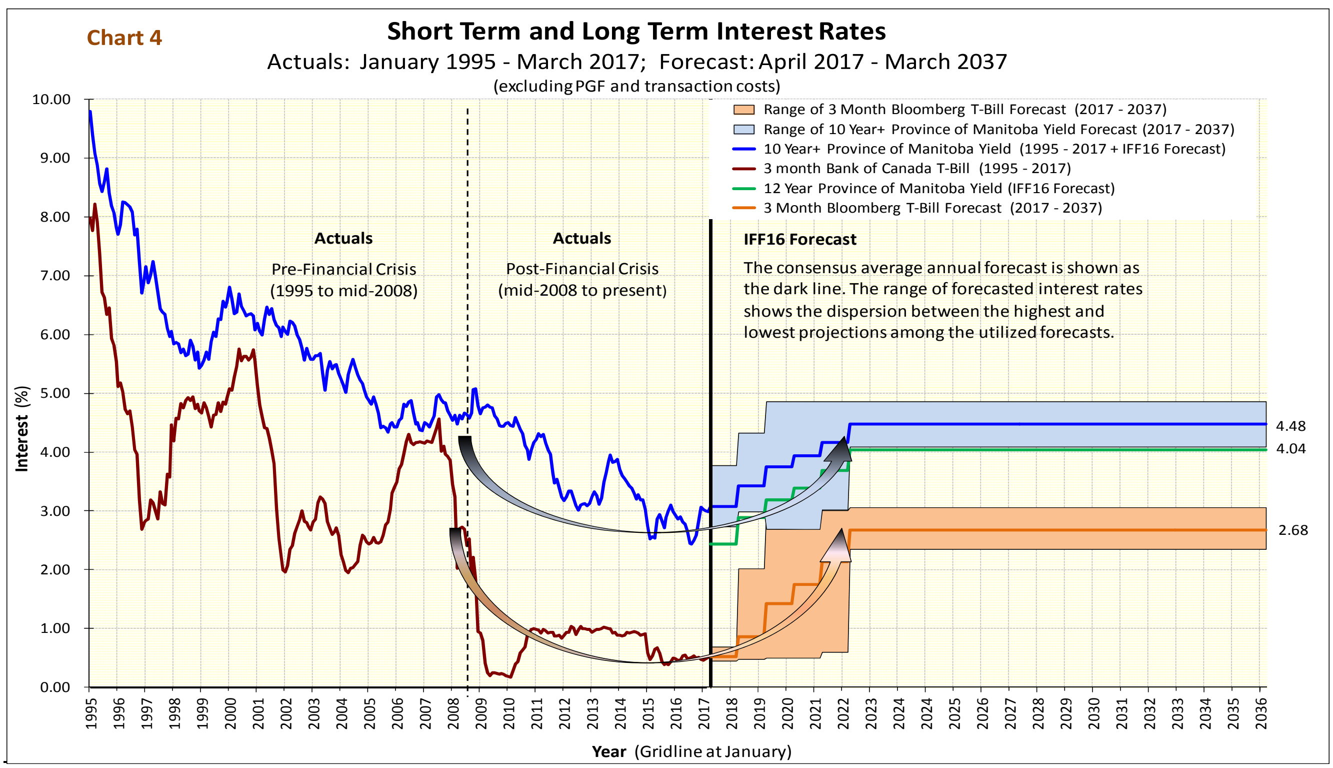
Although economic forecasts during the last few years have generally called for a quicker economic recovery and correspondingly higher interest rates, on an actual basis, the strength and pace of a recovery has been subdued. As a result, monetary policy interventions have continued to anchor interest rates at historically low levels.

To illustrate the changes and trends affecting Manitoba Hydro's short and long term interest rates from 1995 to 2036, the following chart uses 3 month T-Bills for a measure of short term interest rates (red line) and the Province of Manitoba 10 Year+ bond yields for long term interest rates (blue line).[3]

IFF16 will no longer utilize the Manitoba Hydro 10 Yr+ rate (the average of the 10 and 30 year Province of Manitoba bond yields) for forecasting the Corporation's new debt issuance as IFF16 has modeled a reduction of the Weighted Average Term to Maturity (WATM) of forecast Canadian debt issuance from 20 to 12 years. While Manitoba Hydro will continue to support benchmark Canadian maturity terms of 5, 10 and 30 years, the issuance in the 5 year sector will increase from historical debt issuance levels. Manitoba Hydro modeled various debt issuance scenarios with the goal of keeping the interest rate risk close to previous IFF risk levels while decreasing cost. The 12 year terming with the following distribution achieved this goal:

15% floating and 85% fixed (40% in 5 year issuance, 25% in 10 year issuance, 20% in 30+ year issuance)

This 12 year interest rate forecast is represented in the following graph by the green line.



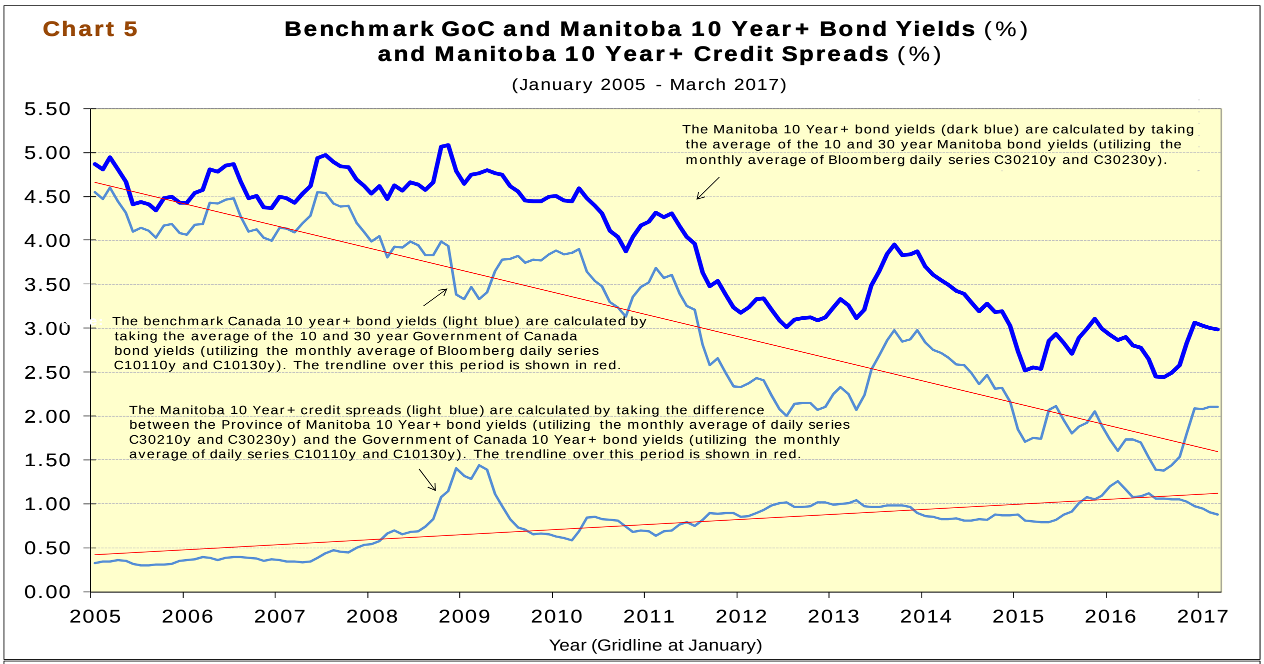
[3] The 10 Year+ Province of Manitoba bond yields (blue line) are calculated by taking the average of the 10 and 30 year Province of Manitoba bond yields. Actual 10 Year+ yields utilize the monthly average of Bloomberg daily series C30210y and C30230y. Forecast 10 Year+ yields are derived from a consensus of external forecast views for the average of 10 and 30 year forecasts. The forecasted long term debt credit spread between the Government of Canada and the Province of Manitoba has been added to each of the forecasters' Government of Canada long term debt forecasts, so that all of the long term debt interest rate projections illustrate Province of Manitoba yields. The long term interest rates exclude the 1.00% PGF and transaction costs (estimated at 6 basis points or 0.06%).

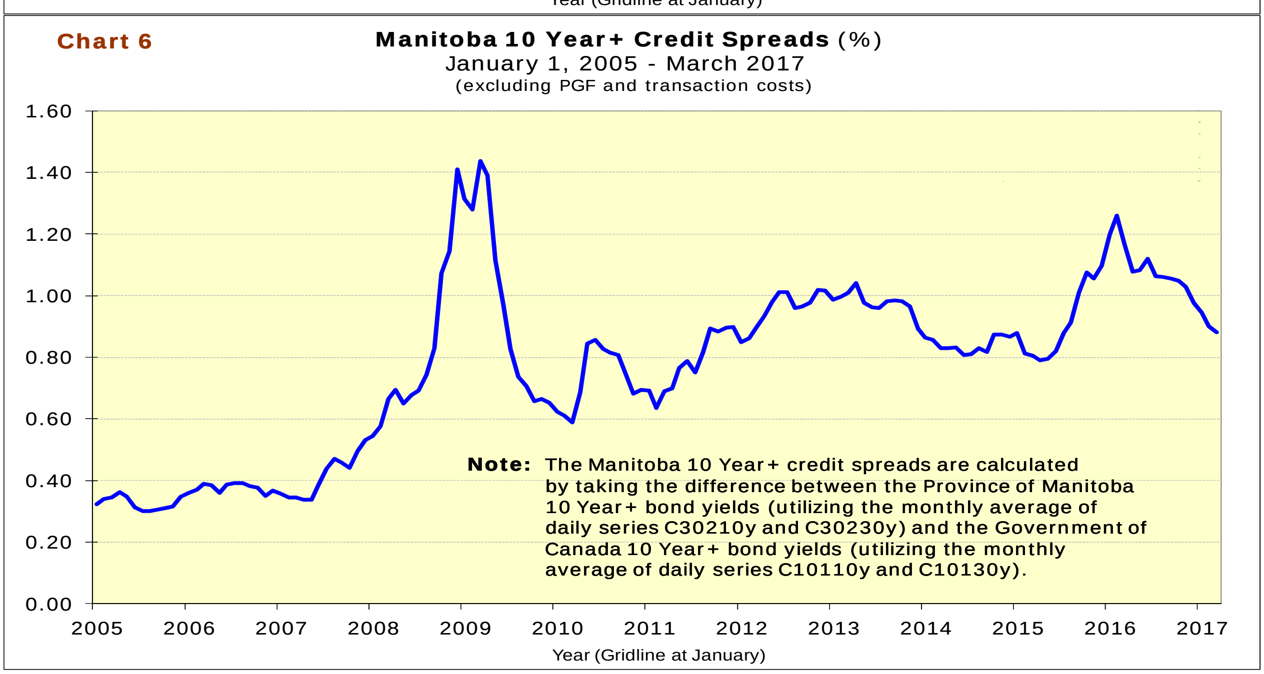
As shown in Chart 5, the Province of Manitoba 10 Year+ bond yields (dark blue line) are comprised of two primary components (shown in the light blue lines): 1) the benchmark Government of Canada (GoC) 10 Year+ bond yields; and 2) the Province of Manitoba 10 Year+ credit spreads.

The credit spread represents the risk premium investors demand over the benchmark GoC bonds to hold the Province of Manitoba bonds. As shown in the red trend lines, the decline in the yields for benchmark GoC bonds have been partially offset by credit spreads that have generally drifted wider over the past ten years.

While the GoC yields are mostly influenced by Bank of Canada monetary policy and external market forces; the credit spreads can be influenced by actions undertaken by Manitoba. Chart 6 provides enhanced focus to the credit spreads by zooming in on the y-axis.

A primary driver of the elevated credit spread levels experienced since the financial crisis has been the growth in the supply of federal, provincial and municipal debt that has been brought to the market. It is anticipated that the high levels of government debt issuance will continue to apply upward pressure on provincial credit spreads.





As previously described, from a market demand perspective, issuance in the government sector during the last two years was characterized by periods of volatility and uneven market tone for provincial bonds and a re-pricing of liquidity in the provincial markets with widening credit spreads for all but the most liquid issuers.

As liquidity improved towards the end of 2016 on the back of continued investor demand and a sustained bid for credit, credit spreads tightened across the curve. To date in 2017, credit spreads have demonstrated a modest tightening bias thus far on the back of better buying activity and stronger demand for credit.

The level of Manitoba Hydro's debt financing may apply pressure on the province's credit spreads. To obtain sufficient demand for the increasing supply of Manitoba bonds, pricing incentives may be required for investors in the form of wider credit spreads and therefore higher bond yields. In order to mitigate the pressure on Manitoba credit spreads, Manitoba Hydro will continue to undertake a number of debt management activities, such as:

- Reducing the interest rate risk exposure on the existing debt portfolio by maintaining the proportion of floating rate debt at or below 10% of the total debt portfolio.
- Managing the refinancing risk within the existing debt portfolio by having a relatively smooth debt maturity schedule.
- Reducing Manitoba Hydro's liquidity risk and enhancing financing flexibility by maintaining positive cash balances and/or access to liquidity.
- Establishing benchmark sized debt issues so that investors may reduce their market risk by having liquid bonds that can be readily traded in the financial markets.
- Diversifying the investor base by varying the terms to maturity for debt issuance so that investors with different term preferences may participate in Manitoba issues.
- Diversifying the investor base beyond the domestic Canadian capital markets by issuing Manitoba bonds into international markets.

The extraordinary interest rate environment has provided the opportunity for Manitoba Hydro to secure low cost, stable funding. As shown on the following charts, since 2006/07, the debt portfolio's weighted average term to maturity of its market debt portfolio has increased by over 5 years and the net weighted average interest rate has decreased by over 2.0%.

Chart 7 **Weighted Average Term to Maturity of Market Debt** (Years)
(For the Fiscal Year Ended March 31)

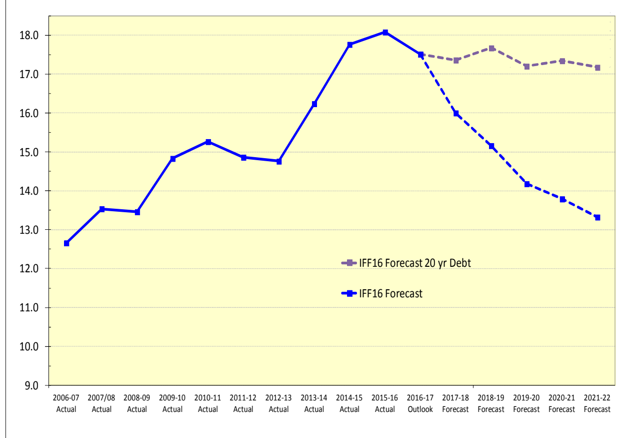
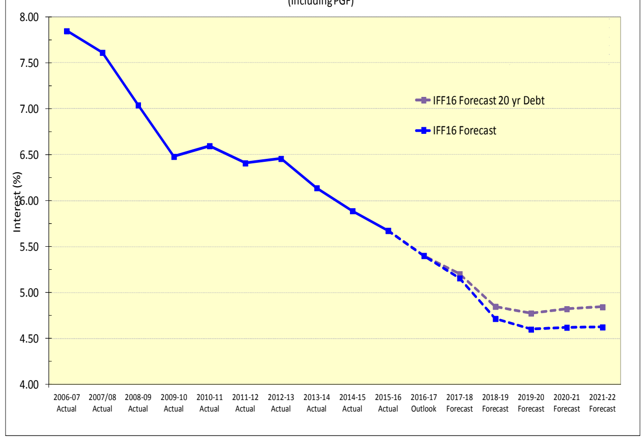


Chart 8 **Weighted Average Interest Rate**
For the Fiscal Year Ended March 31
(Including PGF)



The planned change in IFF16 to reduce the WATM for new issuance to 12 years, which is aligned with the debt retirement opportunity to match future cash flows with debt maturities, will return the WATM to pre-crisis levels, while expecting to beneficially lowering the WAIR.

Against the backdrop of unprecedented capital borrowing requirements and rising interest rates, Manitoba Hydro is in a period of elevated sensitivity to interest rate changes. Manitoba Hydro's **interest rate policy** on its existing debt portfolio is to limit the aggregate of:

i) floating rate debt,
ii) short term debt, and
iii) fixed rate long term debt to be refinanced within the subsequent 12 month period;

to a maximum of 35% of the total debt portfolio.

Manitoba Hydro's **interest rate risk guidelines** for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio. During years in which there are high levels of refinancings and/or new borrowings for prospective cash requirements, in order to manage the overall interest rate risk profile, the Corporation's interest rate risk on its existing debt portfolio may be reduced by decreasing the percentage of aggregated floating rate debt and short term debt to below 15% of the total debt portfolio.

During the past few years, in order to mitigate the interest rate risk arising from the significant level of new capital borrowing requirements, the interest rate risk on the existing debt portfolio has been reduced by decreasing the percentage of floating rate debt within the existing debt portfolio and by selecting debt maturities, that upon refinancing will not compete with new borrowing requirements. Chart 9 shows Manitoba Hydro's interest rate risk profile on the existing debt portfolio as at March 31, 2017.

Chart 9 **Summary of Interest Rate Risk Profile** (%)
(As at March 31, 2017)

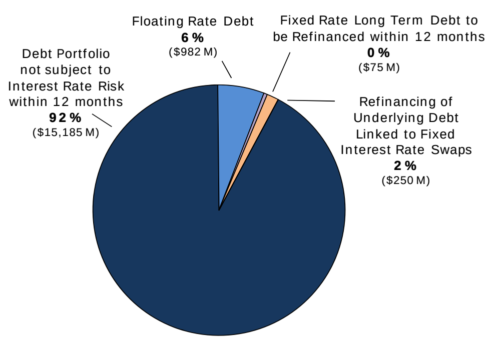
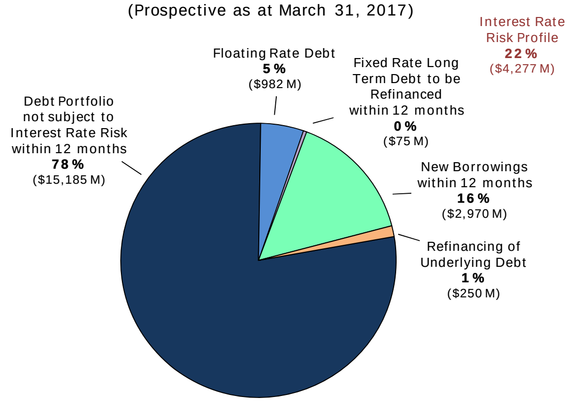


Chart 10, which includes new borrowings and refinancing of underlying debt within the next 12 months, shows that approximately 22% (or $4.3 billion) of the prospective debt portfolio will be subject to interest rate risk over the next 12 months.

Chart 10 **Summary of Interest Rate Risk Profile** (%)
(Prospective as at March 31, 2017)



Foreign currency exchange risk represents the potential for financial gain or loss due to foreign exchange movements for any transaction denominated in a currency other than Canadian (CAD) funds.

The past two years have also seen a significant change in the USD/CAD foreign currency exchange rate. Some of CAD weakness was due to a Canadian economy that has been underperforming relative to the U.S. economy; however, the pressure on commodity prices and in particular oil has been a primary driver. For example, the Canadian dollar had strengthened to the 1.19 range in early May 2015 on the back of rallying oil prices, before weakening to approximately 1.41 by January 31, 2016 due to the retracement in oil prices and the U.S. lift-off in rates while the BoC remains in an extended pause. Since then, oil prices have rebounded slightly and stabilized, which led to the dollar spending much of the past six months hovering between 1.30 and 1.35, closing at approximately 1.33 as of March 31, 2017. The continued divergence in monetary policy is expected to continue to weigh on the currency in 2017.

Manitoba Hydro has significant export revenues denominated in United States dollars (USD); however, the Corporation's exposures to foreign currency rate fluctuations on USD revenues are managed with the combination of natural and accounting hedges. For example, to the extent that the underlying USD inflows and outflows are in balance, while a strengthening US dollar will increase the translation of US export revenues into CAD, this change will be offset by increases in the translation of US dollar expenses (such as US dollar interest expense) into CAD.

As part of the Corporation's foreign currency exchange risk management program, in order to mitigate the foreign currency exchange risk on USD revenues,

REFERENCE:

PUB/MH I-32 (a)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please discuss how the Corporation may revise its debt management strategy based on IFF15-level rate increases (3.95%) rather than what is being proposed in IFF16 Update with Interim.

b) Please discuss the change in the interest rate refinancing risk profile.

RATIONALE FOR QUESTION:

RESPONSE:

a) As seen in chart 13 of the Debt Management Strategy (Appendix 3.5 of the GRA), in order to reduce the weighted average term to maturity (WATM) on new debt issuance to 12 years, Manitoba Hydro would be more heavily weighting maturities of between 3 to 10 years as compared to the WATM modeling of 20 years in previous IFFs. However, as indicated in the Debt Management Strategy, this reduction in forecasted term to maturity is subject to change if operating cost reductions, export price increases, and PUB approved rate increases result in an expectation of insufficient cash flow to enable the risk/reward balance of this new terming strategy.

   Due to the layering of additional maturities at the shorter end of the maturity spectrum, it is critical that forecasted cash flows from expected rate increases (and cost savings) do materialize in order to retire a portion of the debt as it matures in order to mitigate refinancing risk. If Keeyask experiences construction delays which extend the in-service date, the delay in new capital borrowings would pressure interest rate risk in a period with higher than previously forecast refinancings.

If Manitoba Hydro were to assume annual rate increases of 3.95% as opposed to the rates being proposed in MH16 Update with Interim, the Corporation would have to consider revising its debt management strategy to increase the WATM of new debt issuance in order to keep the balance of risks at a manageable level and commensurate with the potential savings from borrowing at the lower rates typically associated with shorter maturities. If the outlook for future cash flows and/or the timing of borrowing requirements should change, a longer WATM profile may be found to be prudent risk management and which consequentially would also increase its weighted average interest rate compared to the MH16 Update with Interim forecast. All else being equal, this would be expected to erode or eliminate the interest savings opportunity from a shortened maturity profile. The benefits of interest savings would be re-evaluated in context of increased near-term refinancing risk.

b) If Manitoba Hydro were to adopt MH15 level rate increases with the MH16 Update with Interim, there would be a significant reduction in cash available for debt retirement as well as an increase in debt maturities in the period 2023-2032. If Manitoba Hydro does not realize the cash flow as planned in MH16 Update with Interim, interest rate risk will increase in comparison to previous plans as the Corporation will be refinancing more long term debt earlier than previously forecast. Without the requested rate increases, the ratio of cash available for debt retirement to debt maturities is significantly reduced thus increasing the Corporation's refinancing risk. As seen in the table below, in the ten year period from 2023-2032, Manitoba Hydro would see a decrease of $6.1 billion in cash available for debt retirement while in the same timeframe see an increase of $1.8 billion in debt maturities. The table below summarizes the impact of adopting MH15 level rate increases for 5 and 10 year timeframes:

Ratio of Cash Available for Debt Retirement to Debt Maturities
(in Millions of Dollars)

5 year Period From 2023-2027	**Cash Available for Debt Retirement**	**Debt Maturities**	**Ratio**
IFF16 Update with Interim with IFF15 Level Rate Increases	$225.1	$9,665.7	2.3%
IFF16 Update with Interim	$3,140.8	$9,343.2	33.6%
Difference	($2,915.8)	$322.5	
10 year Period From 2023-2032			
IFF16 Update with Interim with IFF15 Level Rate Increases	$2,411.1	$16,499.1	14.6%
IFF16 Update with Interim	$8,524.8	$14,724.1	57.9%
Difference	($6,113.7)	$1,775.0	

Without the expectation of having cash flow available for debt retirement as proposed in MH16 Update with Interim, a 12 year WATM terming strategy could unduly pressure the Corporation's risk profile particularly should other forecast risks materialize. As demonstrated in the table above, a significantly lower proportion of maturing debt is "covered" by cash availability if 3.95% rate increases are assumed. Regardless of debt terming strategy or rate increase profile, interest expense will be, by a factor of approximately 1.5x or more, the largest expense of Manitoba Hydro. Therefore, it is a significant contributor to potential volatility in revenue requirement. In the absence of an expectation of sufficient cash flows, Manitoba Hydro is unlikely to conclude its ratepayers are best served by significantly increasing refinancing risk in the fairly near term in order to capture interest savings. The 12 year terming strategy is only prudent as a component of a financial plan that sees the Corporation abating the growth of its debt prior to the completion of Keeyask and accelerating its return to more prudent, manageable and sustainable debt levels thereafter.

REFERENCE:

PUB MFR 78

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain how the weighted average interest rate is calculated and where in the evidence the required inputs can be found.
b) With respect to Figure 1 in PUB MFR 78, please extend the graph to include the years up to 2033/34.
c) Please include in the response to part (b) the weighted average interest rates based on: i) IFF14, ii) IFF15, and iii) IFF16-Updated.

RATIONALE FOR QUESTION:

To understand the basis for the weighted average interest rate calculation and how the values have changed from previous forecasts.

RESPONSE:

a) The weighted average interest rate for a given year is calculated by dividing interest expense by the principal notional equivalent (Pn) of debt outstanding (e.g. If $100M of debt is outstanding for 6 months of the year, the Pn is $50M). The two components are obtained as follows:

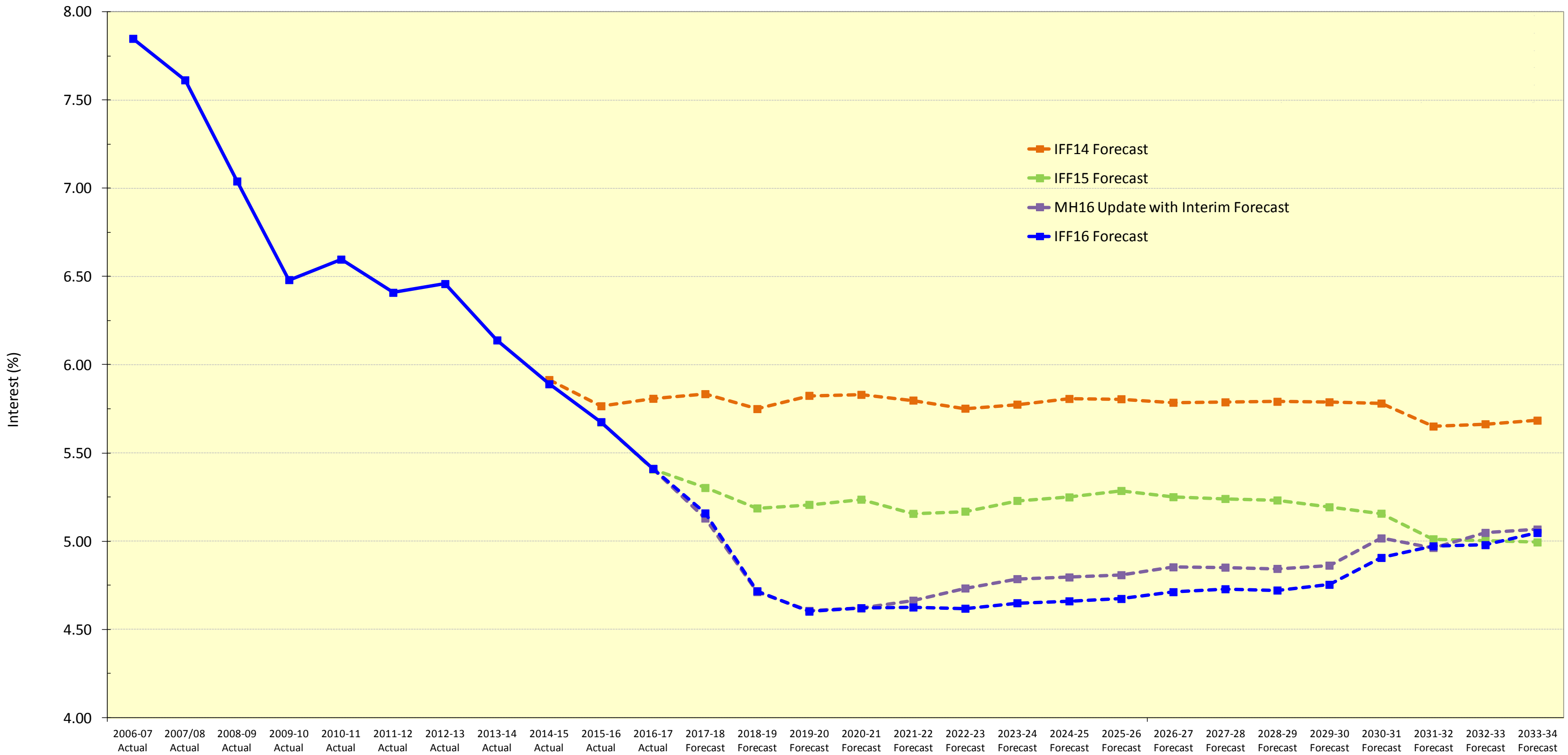
Interest Expense:	CAD and USD Long Term Debt Interest Expense (in CAD Dollars)
	+ Short Term Debt Interest Expense
	+ Provincial Guarantee Fee
	+ Amortization of Premiums/Discounts and Commissions
Pn:	CAD and USD Pn (in CAD)
	+ Short Term Debt Pn

Response to parts b) and c):

The following chart shows a reduction in the weighted average interest rate (WAIR) of Manitoba Hydro's debt portfolio in the first 12 years of the IFF16 and MH16 Update with Interim vs both IFF14 and IFF15, thus providing the Corporation with cost savings. This is possible due to the decision to change the terming assumption for new long term debt issuance in the financial forecasting model to 12 years in IFF16 from the previous 20 years used in IFF14 and IFF15, as well as overall lower forecast benchmark rates. It should be noted that the reversal in the IFF16 WAIR beginning in fiscal year 2030 is the result of the forecasting model's simplifying assumption that all new long term debt issued will be at a 12 year term, which would notionally result in large refinancing requirements 12 years after Manitoba Hydro's peak borrowing years. However, in practice, Manitoba Hydro's actual terming of new debt issuance, while targeting a WATM of 12 years, will vary from this forecast term. Manitoba Hydro will choose debt maturities which create a debt maturity profile to allow for debt to be retired as surplus cash flows become available.

Chart 8

Weighted Average Interest Rate
For the Fiscal Year Ended March 31
(Including PGF)



REFERENCE:

PUB MFR 78
Appendix 3.5
2015/16 & 2016/17 GRA, Appendix 3.7

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Manitoba Hydro's debt management strategy, as outlined at the time of the last GRA, indicated that the Corporation would continue to favour long-term fixed rate financing with maturities of 10 years or longer such that the weighted average term to maturity would be roughly 17 years over the forecast period to 2016/17. However, in the current Application Manitoba Hydro has set out a different debt management strategy that relies on shorter term borrowings and would see the weighted average term to maturity decline to less than 14 years (Appendix 3.5, Chart 7). What has changed since the last GRA that resulted in the previous strategy no longer being appropriate?
b) With respect to Appendix 3.5, please provide a revised version of Chart 8 that extends the projection for both forecasts out to 2033/34.
c) Please update the response to part (b) based on IFF16-Updated.

RATIONALE FOR QUESTION:

To understand the rationale behind Manitoba Hydro's new debt management strategy.

RESPONSE:

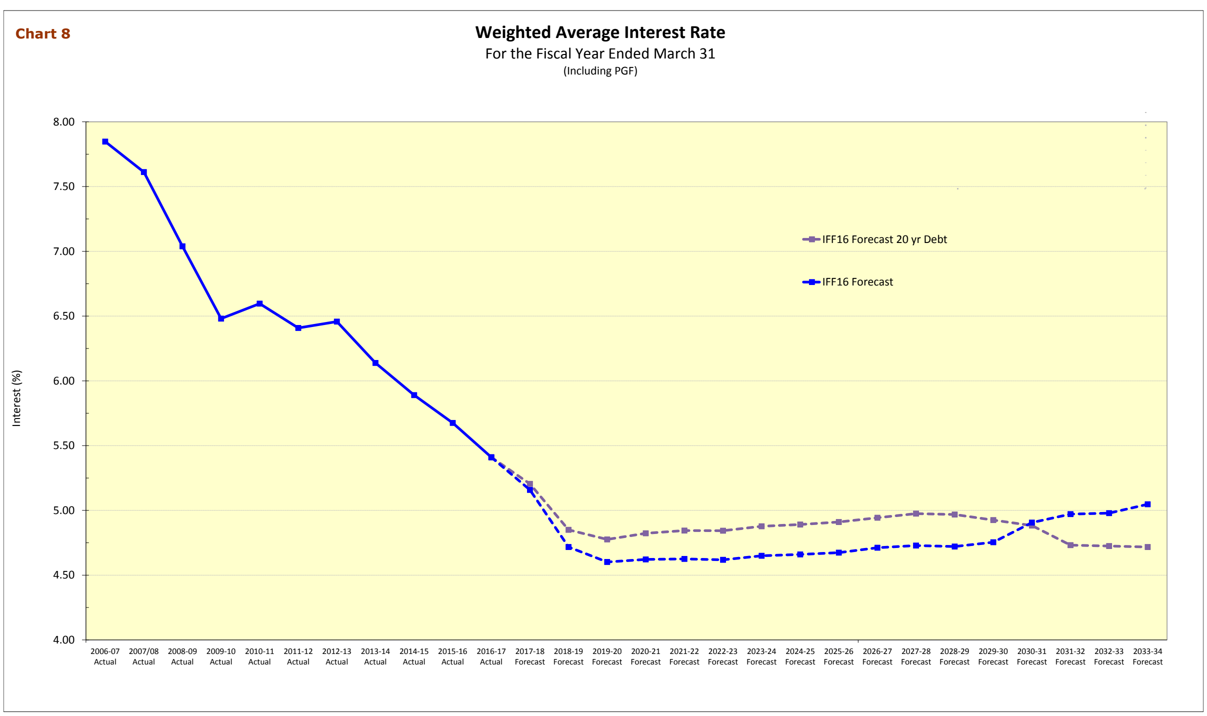
a) Please see Manitoba Hydro's response to PUB/MH I-28c.

Response to parts b) and c):

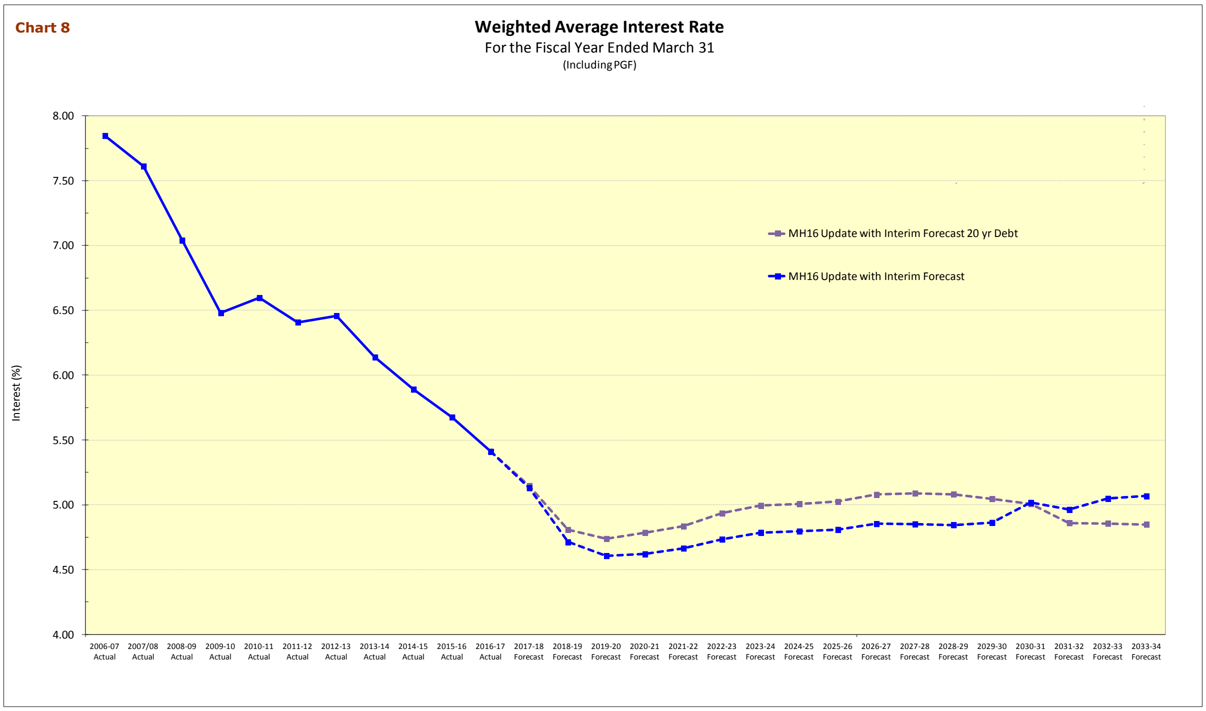
The following two charts show a reduction in the weighted average interest rate (WAIR) of Manitoba Hydro's debt portfolio in the first 12 years of the forecast, thus providing the Corporation with cost savings. This is possible due to the decision to change the terming assumption for new long term debt issuance in the financial forecasting model to 12 years from the previous 20 years.

It should be noted that the reversal in the WAIR beginning in fiscal year 2030 is the result of the forecasting model's simplifying assumption that all new long term debt issued will be at a 12 year term, which would notionally result in large refinancing requirements 12 years after Manitoba Hydro's peak borrowing years. However, in practice, Manitoba Hydro's actual terming of new debt issuance, while targeting a weighted average term to maturity (WATM) of 12 years, will vary from this forecast term. Manitoba Hydro will choose debt maturities which create a debt maturity profile to allow for debt to be retired as surplus cash flows become available.

The following revised version of Chart 8 has been extended to 2033/34:



The following version of Chart 8 based on MH16 Update with Interim has been extended to 2033/34:



REFERENCE:

Appendix 3.5 Interest Rate Risk Chart 13

PREAMBLE TO IR (IF ANY):

MH is forecasting changing the distribution of debt issues to achieve a 12 year terming: 15% floating and 85% fixed (40% in 5-year issuance, 25% in 10-year issuance, 20% in 30+ year issuance).

MH has stated in order to mitigate the pressure on Manitoba credit spreads, that it would reduce the interest rate risk exposure on the existing debt portfolio by maintaining the proportion of floating rate debt at or below 10% of the total debt portfolio.

At the 2015 & 2016 GRA MH articulated a further strategy of reducing the interest rate risk exposure on the existing debt portfolio by extending the weighted average term to maturity by issuing longer dated debt, including the issuance of ultra-long debt with terms to maturity beyond 30 years. [PUB/MH II-72 a-d]

QUESTION:

a) Given the forecast mix of borrowings please provide an update to Chart 9 and Chart 10 in 2020.
b) Please explain whether the 40% assumed issuance maturing in 5 years increases or decrease Interest rate risk.
c) Please explain why MH has dropped the strategy of extending the weighted average term to maturity given the interest rate environment.

RATIONALE FOR QUESTION:

RESPONSE:

a) Given the planned mix of borrowings in the Debt Management Strategy (which was prepared in conjunction with IFF16), the projected interest rate risk profiles as of

March 31, 2020 are provided. Chart 10 below, which includes new borrowings within the next 12 months, shows that approximately 20% (or $5.2 billion) of the prospective debt portfolio will be subject to interest rate risk over the next 12 months as at March 31, 2020. While this is down from 22% at March 31, 2017 in Appendix 3.5, there has been a trade off in risk between that stemming from new borrowings (down 9%) and that related to floating rate & refinancing risk (up 7%).

Chart 9 **Summary of Interest Rate Risk Profile** (%)
(As at March 31, 2020)

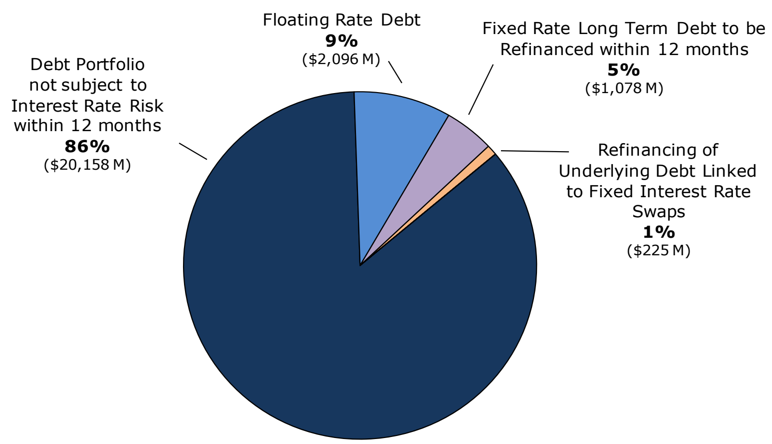
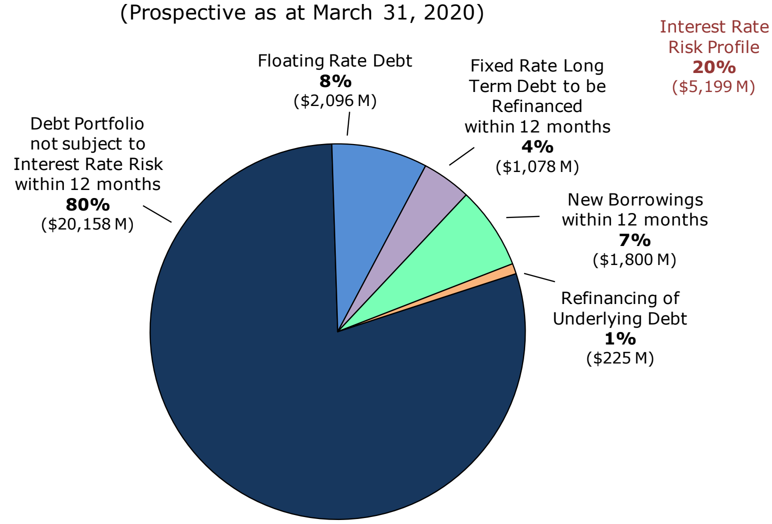


Chart 10 **Summary of Interest Rate Risk Profile** (%)
(Prospective as at March 31, 2020)



b) Manitoba Hydro's current financial plan addresses the serious deterioration in the Corporation's financial position. In order to mitigate customer rate impacts, Manitoba Hydro explored opportunities that would provide cost savings to the Corporation. With the increased expected cash flow from IFF16, Manitoba Hydro will be able to retire long term debt in advance of previous IFFs. If all forecast assumptions hold, an increase in planned 5 year debt issuance will provide cost savings to the Corporation while maintaining interest rate risk at reasonable levels. There is no interest rate risk on debt which is reasonably anticipated to be retired upon maturity using positive cash flow. However, if Manitoba Hydro does not obtain its requested level of rate increases and is not able to realize the cash flow as planned, interest rate risk will increase in comparison to previous plans as the Corporation will be refinancing more long term debt earlier than previously forecast.

c) In the decade prior to the preparation of IFF16, Manitoba Hydro's debt management strategies and activities were significantly impacted by the Corporation's increasing cash requirements, as well as the financial market conditions arising out of the global financial crisis. In preparation for the increasing levels of capital investment and debt financing, the interest rate risk on the existing debt portfolio was reduced during this time frame by decreasing the percentage of floating rate debt within the existing debt portfolio. In order to mitigate refinancing risk, Manitoba Hydro also adopted a "leapfrogging" strategy that favored longer dated debt maturities that largely skipped over the future period of unprecedented borrowings for new cash requirements, thereby also enhancing debt stability by extending the debt portfolio's weighted average term to maturity (WATM) by 5 years from 12.5 years at March 31, 2007 to 17.5 years at March 31, 2017. Manitoba Hydro also took advantage of the low interest rate environment to decrease the debt portfolio's weighted average interest rate (WAIR) by over 2% from 7.75% at March 31, 2007 to 5.41% at March 31, 2017.

The leapfrogging approach undertaken since 2008 along with Manitoba Hydro's new financial plan, have provided the opportunity for the Corporation to consider shortening the term to maturity of new debt issuance. However, there are risk and reward tradeoffs that must be considered when adjusting the expectations for shorter weighted average term to maturity and the associated reduction in weighted average interest rate:

- The financial benefit associated with this opportunity has the potential to provide approximately $500 million reduction in debt servicing costs over the next 10 years to the end of 2026/27.
- The amount of debt maturing increases in 2023-2027 due to an increased amount of three and five year debt issued in 2018-2022. During this period, the proposed change in weightings will add approximately $3 billion in debt coming due as compared to previous weightings which produce a WATM for new debt issuance of 20 years. As discussed in part b) above, without increased cash flow expectations, this would elevate refinancing risk as compared to previous IFFs. Previous IFFs projected minimal net income and cash flow during this period. Should cash flows from expected rate increases and cost savings not materialize, this refinancing risk will not have been mitigated as surplus cash will not be available for debt retirement.

Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of:

i. floating rate debt,
ii. short term debt, and
iii. fixed rate long term debt to be refinanced within the subsequent 12 month period;
iv. to a maximum of 35% of the total debt portfolio.

Manitoba Hydro's interest rate risk guidelines for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio.

When selecting the new forecast weightings for new debt issuance that are used in IFF16, Manitoba Hydro considered the impact to the interest rate risk profile and selected weightings which would keep the risk profile within Manitoba Hydro policy and guideline limits and targets, while providing for cost savings versus the previously used forecast weightings.

IFF16, with the new 12 year weighted average term to maturity for new debt issuance assumption, provides for interest rate risk profiles in all years of the forecast which are below the policy and guideline limits thus limiting interest rate risk for Manitoba Hydro. Given the current expectation that interest rates are expected to rise in the next few years, Manitoba Hydro deems it to be prudent to remain at the lower end of its interest rate risk policy and guideline limits.

Should underlying forecast assumptions (including rate increases, cost savings, export prices, interest rates, in-service dates) not materialize as planned, Manitoba Hydro will re-evaluate and adjust its debt management strategy and the targeted weighted average term to maturity of new debt issuance as it deems necessary. All else being equal, this would be expected to erode the interest savings opportunity from a shortened maturity profile. The benefits of interest savings would be re-evaluated in context of increased near-term refinancing risk.

TAB 7

APPENDIX A: DEPENDABLE SUPPLY & DEMAND

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2016 Planning Assumptions
No New Resources

Fiscal Year		2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Power Resources																		
New Power Resources																		
New Hydro																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 **Total New Power Resources**	1+2																	
Base Supply Power Resources																		
Existing Hydro		5 150	5 255	5 690	5 771	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766
Existing Thermal																		
Brandon Coal - Unit 5		92																
Selkirk Gas		33	33	33	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Brandon Units 6-7 SCGT		278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
Contracted Imports		688	688	605	605	605	605	605	220	220	220	220	220					
Proposed Imports														220	220	220	220	220
Exisitng Wind		52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Generation Outages Over System Peak																		
Bipole III Reduced Losses		90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**6 383**	**6 396**	**6 738**	**6 911**	**6 906**	**6 906**	**6 906**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**
5 **Total Power Resources**	3+4	**6 383**	**6 396**	**6 738**	**6 911**	**6 906**	**6 906**	**6 906**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**
Peak Demand																		
2016 Base Load Forecast		4 905	4 948	5 010	5 066	5 131	5 195	5 259	5 318	5 379	5 435	5 497	5 585	5 673	5 773	5 882	5 994	6 108
Less: 2016 DSM Forecast		- 222	- 321	- 406	- 487	- 532	- 569	- 603	- 638	- 673	- 708	- 744	- 779	- 814	- 819	- 825	- 830	- 835
6 **Manitoba Net Load**		4 683	4 627	4 604	4 579	4 599	4 626	4 656	4 680	4 706	4 727	4 753	4 806	4 859	4 954	5 057	5 164	5 273
Contracted Exports		727	727	889	1 018	990	990	990	495	495	385	385	385	385	385	385	385	385
Proposed Exports																		
7 **Total Exports**		727	727	889	1 018	990	990	990	495	495	385	385	385	385	385	385	385	385
8 **Total Peak Demand**	6+7	**5 410**	**5 354**	**5 493**	**5 597**	**5 589**	**5 616**	**5 646**	**5 175**	**5 201**	**5 112**	**5 138**	**5 191**	**5 244**	**5 339**	**5 442**	**5 549**	**5 658**
9 Reserves		552	545	546	544	546	550	553	555	558	559	563	569	575	587	599	612	625
10 **System Surplus**	5-8-9	**421**	**497**	**699**	**770**	**771**	**740**	**707**	**791**	**762**	**850**	**820**	**761**	**702**	**595**	**480**	**360**	**238**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2016 Planning Assumptions
No New Resources

	Fiscal Year		2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52
	Power Resources																		
	New Power Resources																		
	New Hydro																		
1	**Total New Hydro**																		
	New Thermal																		
	SCGT																		
	CCGT																		
2	**Total New Thermal**																		
3	**Total New Power Resources**	1+2																	
	Base Supply Power Resources																		
	Existing Hydro		5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766	5 766
	Existing Thermal																		
	Brandon Coal - Unit 5																		
	Selkirk Gas		125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
	Brandon Units 6-7 SCGT		278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
	Contracted Imports																		
	Proposed Imports		220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
	Exisiting Wind		52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
	Generation Outages Over System Peak																		
	Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4	**Total Base Supply Power Resources**		**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**
5	**Total Power Resources**	3+4	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**
	Peak Demand																		
	2016 Base Load Forecast		6 227	6 346	6 465	6 584	6 703	6 822	6 941	7 060	7 179	7 298	7 417	7 536	7 655	7 774	7 893	8 012	8 132
	Less: 2016 DSM Forecast		- 840	- 845	- 850	- 855	- 860	- 863	- 866	- 869	- 873	- 875	- 878	- 876	- 874	- 873	- 872	- 872	- 872
6	**Manitoba Net Load**		5 387	5 501	5 615	5 729	5 843	5 959	6 075	6 191	6 306	6 423	6 539	6 660	6 781	6 901	7 021	7 140	7 260
	Contracted Exports		110	110	110	110	110												
	Proposed Exports																		
7	**Total Exports**		110	110	110	110	110												
8	**Total Peak Demand**	6+7	**5 497**	**5 611**	**5 725**	**5 839**	**5 953**	**5 959**	**6 075**	**6 191**	**6 306**	**6 423**	**6 539**	**6 660**	**6 781**	**6 901**	**7 021**	**7 140**	**7 260**
9	Reserves		636	649	663	677	690	703	717	731	745	759	773	787	802	816	831	845	859
10	**System Surplus**	5-8-9	**388**	**261**	**133**	**5**	**- 122**	**- 141**	**- 271**	**- 401**	**- 530**	**- 661**	**- 791**	**- 926**	**-1 062**	**-1 196**	**-1 331**	**-1 464**	**-1 598**

System Firm Summer Peak Demand and Capacity Resources (MW) @ generation
2016 Planning Assumptions
No New Resources

Fiscal Year		2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Power Resources																		
New Power Resources																		
New Hydro																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 **Total New Power Resources**	1+2																	
Base Supply Power Resources																		
Existing Hydro		5 160	5 175	5 520	5 781	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776
Existing Thermal																		
Brandon Coal - Unit 5		92	92															
Selkirk Gas		33	33	33	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Brandon Units 6-7 SCGT		269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269
Contracted Imports																		
Proposed Imports																		
Exisitng Wind		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Generation Outages Over System Peak		- 102	- 102	- 102	- 102	- 102	- 102	- 102	- 102	- 102	- 102	- 102	- 102	- 98	- 98	- 98	- 98	- 98
Bipole III Reduced Losses		90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**5 582**	**5 597**	**5 840**	**6 193**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 192**	**6 192**	**6 192**	**6 192**	**6 192**
5 **Total Power Resources**	3+4	**5 582**	**5 597**	**5 840**	**6 193**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 188**	**6 192**	**6 192**	**6 192**	**6 192**	**6 192**
Peak Demand																		
2016 Base Load Forecast		3 451	3 503	3 565	3 609	3 656	3 703	3 749	3 791	3 835	3 877	3 922	3 987	4 053	4 126	4 206	4 287	4 371
Less: 2016 DSM Forecast		- 113	- 166	- 204	- 238	- 267	- 297	- 325	- 355	- 385	- 418	- 453	- 489	- 524	- 529	- 533	- 538	- 542
6 **Manitoba Net Load**		3 338	3 337	3 361	3 371	3 389	3 406	3 424	3 436	3 450	3 459	3 469	3 498	3 529	3 597	3 673	3 749	3 829
Contracted Exports		1 470	1 470	1 549	1 678	1 650	1 650	1 650	715	715	605	605	605	605	605	605	605	605
Proposed Exports																		
7 **Total Exports**		1 470	1 470	1 549	1 678	1 650	1 650	1 650	715	715	605	605	605	605	605	605	605	605
8 **Total Peak Demand**	6+7	**4 808**	**4 807**	**4 910**	**5 049**	**5 039**	**5 056**	**5 074**	**4 151**	**4 165**	**4 064**	**4 074**	**4 103**	**4 134**	**4 202**	**4 278**	**4 354**	**4 434**
9 Reserves		405	405	410	412	414	416	418	410	411	411	412	416	419	428	437	446	456
10 **System Surplus**	5-8-9	**369**	**385**	**520**	**732**	**735**	**716**	**696**	**1 627**	**1 612**	**1 713**	**1 702**	**1 669**	**1 639**	**1 562**	**1 477**	**1 392**	**1 302**

System Firm Summer Peak Demand and Capacity Resources (MW) @ generation
2016 Planning Assumptions
No New Resources

Fiscal Year		2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52
Power Resources																		
New Power Resources																		
New Hydro																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 **Total New Power Resources**	1+2																	
Base Supply Power Resources																		
Existing Hydro		5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776	5 776
Existing Thermal																		
Brandon Coal - Unit 5																		
Selkirk Gas		125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Brandon Units 6-7 SCGT		269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269	269
Contracted Imports																		
Proposed Imports																		
Exisiting Wind		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Generation Outages Over System Peak		- 98	- 98	- 98	- 98	- 98	- 135	- 135	- 135	- 135	- 135	- 135	- 135	- 135	- 135	- 135		
Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**6 192**	**6 192**	**6 192**	**6 192**	**6 192**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 290**	**6 290**
5 **Total Power Resources**	3+4	**6 192**	**6 192**	**6 192**	**6 192**	**6 192**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 155**	**6 290**	**6 290**
Peak Demand																		
2016 Base Load Forecast		4 457	4 544	4 630	4 717	4 803	4 890	4 977	5 063	5 150	5 236	5 323	5 409	5 496	5 582	5 669	5 756	5 842
Less: 2016 DSM Forecast		- 545	- 549	- 553	- 557	- 561	- 563	- 566	- 569	- 572	- 574	- 576	- 575	- 575	- 574	- 573	- 573	- 573
6 **Manitoba Net Load**		3 912	3 995	4 077	4 160	4 242	4 327	4 411	4 494	4 578	4 662	4 747	4 834	4 921	5 008	5 096	5 183	5 269
Contracted Exports		330	330	330	330	330	220	220	220	220	220	220	220	220	220	220	220	220
Proposed Exports																		
7 **Total Exports**		330	330	330	330	330	220	220	220	220	220	220	220	220	220	220	220	220
8 **Total Peak Demand**	6+7	**4 242**	**4 325**	**4 407**	**4 490**	**4 572**	**4 547**	**4 631**	**4 714**	**4 798**	**4 882**	**4 967**	**5 054**	**5 141**	**5 228**	**5 316**	**5 403**	**5 489**
9 Reserves		462	472	482	492	502	511	521	531	541	551	561	572	582	593	603	614	624
10 **System Surplus**	5-8-9	**1 488**	**1 395**	**1 303**	**1 210**	**1 118**	**1 097**	**1 003**	**910**	**816**	**722**	**627**	**529**	**432**	**334**	**236**	**273**	**177**

Page 17

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2016 Planning Assumptions
No New Resources

Fiscal Year		2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Power Resources																		
New Power Resources																		
New Hydro																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 New Wind																		
4 **Total New Power Resources**	1+2+3																	
Base Supply Power Resources																		
Existing Hydro		21 880	22 356	24 790	24 778	24 746	24 746	24 736	24 726	24 726	24 716	24 706	24 706	24 696	24 696	24 686	24 676	24 676
Existing Thermal																		
Brandon Coal - Unit 5		706	515															
Selkirk Gas		899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899
Brandon Units 6-7 SCGT		2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343
Contracted Imports		2 809	2 809	3 502	3 688	3 688	3 688	3 688	2 321	2 050	2 050	2 050	2 050	1 268	1 113	1 113	1 113	1 113
Proposed Imports														781	936	936	936	936
Hydro Adjustment		903	903	844	844	844	844	844	406	307	307	307	307	307	307	307	307	307
Market Purchases		258	258	957	1 050	1 050	1 050	1 050	2 417	2 688	2 680	2 614	2 646	2 679	2 688	2 688	2 688	2 689
Additional Market Resources																		
Existing Wind		780	780	780	780	780	780	780	780	780	780	780	780	780	780	780	780	780
Bipole III Reduced Losses		101	101	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
5 **Total Base Supply Power Resources**		**30 679**	**30 964**	**34 292**	**34 559**	**34 527**	**34 527**	**34 517**	**34 069**	**33 970**	**33 952**	**33 876**	**33 908**	**33 931**	**33 940**	**33 930**	**33 920**	**33 921**
6 **Total Power Resources**	4+5	**30 679**	**30 964**	**34 292**	**34 559**	**34 527**	**34 527**	**34 517**	**34 069**	**33 970**	**33 952**	**33 876**	**33 908**	**33 931**	**33 940**	**33 930**	**33 920**	**33 921**
Manitoba Domestic Load																		
2016 Base Load Forecast		26 785	27 060	27 410	27 729	28 082	28 435	28 785	29 110	29 447	29 762	30 106	30 602	31 108	31 666	32 273	32 896	33 532
Non-Committed Construction Power																		
Less: 2016 DSM Forecast		- 934	-1 416	-1 732	-2 020	-2 201	-2 369	-2 526	-2 688	-2 845	-3 010	-3 182	-3 356	-3 527	-3 558	-3 590	-3 620	-3 648
7 **Manitoba Net Load**		**25 851**	**25 644**	**25 678**	**25 709**	**25 881**	**26 066**	**26 259**	**26 422**	**26 602**	**26 752**	**26 924**	**27 246**	**27 581**	**28 108**	**28 683**	**29 276**	**29 884**
Contracted Exports		3 441	3 412	4 451	5 155	5 054	5 027	5 027	2 744	2 600	2 185	2 102	2 102	2 102	2 102	2 102	2 102	2 102
Proposed Exports																		
Less: Adverse Water		- 370	- 370	- 370	- 489	- 512	- 512	- 512	- 85									
8 **Total Net Exports**		**3 071**	**3 042**	**4 081**	**4 666**	**4 542**	**4 515**	**4 515**	**2 659**	**2 600**	**2 185**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**
9 **Total Energy Demand**	7+8	**28 922**	**28 686**	**29 759**	**30 375**	**30 423**	**30 581**	**30 774**	**29 081**	**29 202**	**28 937**	**29 026**	**29 348**	**29 683**	**30 210**	**30 785**	**31 378**	**31 986**
10 **System Surplus**	6-9	**1 757**	**2 279**	**4 533**	**4 184**	**4 104**	**3 946**	**3 743**	**4 988**	**4 768**	**5 015**	**4 850**	**4 560**	**4 248**	**3 730**	**3 145**	**2 542**	**1 935**

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2016 Planning Assumptions
No New Resources

	Fiscal Year		2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52
	Power Resources																		
	New Power Resources																		
	New Hydro																		
1	**Total New Hydro**																		
	New Thermal																		
	SCGT																		
	CCGT																		
2	**Total New Thermal**																		
3	New Wind																		
4	**Total New Power Resources**	1+2+3																	
	Base Supply Power Resources																		
	Existing Hydro		24 666	24 656	24 656	24 646	24 646	24 636	24 626	24 626	24 616	24 606	24 606	24 596	24 586	24 586	24 576	24 576	24 566
	Existing Thermal																		
	Brandon Coal - Unit 5																		
	Selkirk Gas		899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899
	Brandon Units 6-7 SCGT		2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343
	Contracted Imports		186																
	Proposed Imports		936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936
	Hydro Adjustment		307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307
	Market Purchases		2 865	2 906	2 970	3 033	3 097	2 703	2 676	2 741	2 806	2 871	2 936	3 003	3 069	3 135	3 202	3 268	3 334
	Additional Market Resources																		
	Existing Wind		780	780	780	780	780	780	780	780	780	780	780	780	780	780	780	780	780
	Bipole III Reduced Losses		177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
5	**Total Base Supply Power Resources**		**33 159**	**33 004**	**33 068**	**33 121**	**33 185**	**32 781**	**32 744**	**32 809**	**32 864**	**32 919**	**32 984**	**33 041**	**33 097**	**33 163**	**33 220**	**33 286**	**33 342**
6	**Total Power Resources**	4+5	**33 159**	**33 004**	**33 068**	**33 121**	**33 185**	**32 781**	**32 744**	**32 809**	**32 864**	**32 919**	**32 984**	**33 041**	**33 097**	**33 163**	**33 220**	**33 286**	**33 342**
	Manitoba Domestic Load																		
	2016 Base Load Forecast		34 193	34 853	35 514	36 174	36 835	37 495	38 156	38 816	39 477	40 137	40 798	41 458	42 119	42 779	43 440	44 100	44 761
	Non-Committed Construction Power																		
	Less: 2016 DSM Forecast		-3 674	-3 701	-3 727	-3 754	-3 780	-3 789	-3 800	-3 811	-3 822	-3 830	-3 839	-3 835	-3 831	-3 828	-3 826	-3 826	-3 825
7	**Manitoba Net Load**		**30 519**	**31 152**	**31 787**	**32 420**	**33 055**	**33 706**	**34 356**	**35 005**	**35 655**	**36 307**	**36 959**	**37 623**	**38 288**	**38 951**	**39 614**	**40 274**	**40 936**
	Contracted Exports		1 066	858	858	858	858	399	307	307	307	307	307	307	307	307	307	307	307
	Proposed Exports																		
	Less: Adverse Water																		
8	**Total Net Exports**		**1 066**	**858**	**858**	**858**	**858**	**399**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**
9	**Total Energy Demand**	7+8	**31 585**	**32 010**	**32 645**	**33 278**	**33 913**	**34 105**	**34 663**	**35 312**	**35 962**	**36 614**	**37 266**	**37 930**	**38 595**	**39 258**	**39 921**	**40 581**	**41 243**
10	**System Surplus**	6-9	**1 574**	**994**	**423**	**- 157**	**- 728**	**-1 324**	**-1 919**	**-2 503**	**-3 098**	**-3 695**	**-4 282**	**-4 889**	**-5 498**	**-6 095**	**-6 701**	**-7 295**	**-7 901**

TAB 8

show what the rate impacts were over time, and the impacts on customers.

I suppose if we spend enough time at anything we can pull it out and try to intelligently organize it, but I -- we're moving away from then differential analysis of the different plans to pulling out specific -- you know, specifically derived calculations. And I'm not sure we're not straying from the purpose of the hearing.

MR. BOB PETERS: So, Mr. Rainkie, as long as the undertaking is provided that we've talked about then, based on the finance expense on a hundred percent of the capital cost, then I won't go down the -- the road for a further undertaking to layer over that net of internally generated funds. And I'll move on, sir, to -- to just talk about the net debt situation as a -- as a new topic, Mr. Rainkie.

THE CHAIRPERSON: Mr. Peters, I wonder if I could go back to have Mr. Rainkie talk about the blip that's occurring in the -- in the rate increases that we're projecting based on the Preferred Development Plan. And this is the -- looking at year 33 out, where we get -- you know, we get three point nine five (3.95), and all of the sudden we get a drop in rates.

And I guess the difficulty I have -- and I understand what you're saying, and that it's hard to predict what the -- what the PUB will approve as rates that far out. But looking at it very tactically, from your perspective, I mean, you're indicating to ratepayers that they'll be paying 3.95 percent out till '31/'32, effectively doubling their rates.

It seems to me that telling them that rates will go up 3.95 percent until 2025 suggests to me that you're going to get a 60 percent rate increase over and above what they're paying now as opposed to a hundred percent rate increase over what they're paying now; a very different picture from a perspective of the ratepayer, I would think. So starting from a base of seven (7) cents, they would go up, say for the sake of argument, four (4) cents, five (5) cents. You're getting twelve (12), which is still competitive with other jurisdictions, as opposed to a doubling of rates, which did -- to the zone of fourteen (14) cents or fifteen (15) cents in today's dollar.

So, tactically, I guess I'm questioning projecting 3.95 out -- 3.95 percent out for twenty-one (21) years, when -- when there might be a better picture that can be drawn for ratepayers than is currently the case. But I'd like to hear your point of view about that.

MR. DARREN RAINKIE: You know, that's a -- that's a really good question, because I pondered that myself as I -- as I started summarizing the evidence in my own mind and wondering how the Board was going to deal with that; what I call the correction factor in that year after the -- you know, the end of the twenty (20) year period. And I actually asked my staff, Could we somehow smooth that out and show a little bit more of what we thought -- thought would really happen, and I was trying to do that a little bit yesterday. So I appreciate the question, actually.

I think what we're -- what we're trying to show in our twenty (20) year forecast is that we're going for all -- for the credit rating agencies and other stakeholders that -- that watch our financial integrity, is that we can -- we can undertake the Development Plan, manage it appropriately, and come back to our financial ratio.

So I think when I -- when I look at the twenty (20) year snippet, it's saying: What do we need to do? What do we need to do to be able to make sure that we can maintain the financial integrity of the Corporation and have reasonable rate increases?

When I move to a longer picture now of

fifty (50) years, and I now have the information to go out that far which we provided in the NFAT filing, I see that correction factor. I see the types of cash flows and net incomes that we're generating after the twenty (20) year period.

So what I -- what I think is, is that probably after -- I can't speak for our Board, but just -- just from a perspective of -- of hashing it out here, we make the investment in these large plants. We update our forecasts every year. And as we see the plans unfold and the cash flow and the net income come in closer term I think we will start easing off on the 3.95s earlier.

I'm a little hesitant to promise that while we're in the middle of a large investment like Conawapa, you know, that comes into service between '29 -- sorry, '26 and '29, I think it is.

So it's tough to predict what we would exactly do, but I would think that what you would do is see -- rather than this -- you know, you would see -- I don't know how the court reporter is going to capture this, but more of a smoothed-out rate increase. And I've actually thought about perhaps drawing one out for the Board, and -- and showing it -- and showing it to you as an undertaking just to -- just to show what we think might happen in the real world.

But I -- that's why I don't believe there's a lot of intergenerational or no intergenerational equity in the plan. Because I think if you look at what happens over the long-term financial picture, we can ease off the 3.95s before the end of the twenty (20) year. I'm -- I would be hesitant to ease off before that when we're in the middle of a large, you know, investment cycle.

I take a bit of comfort, although I know it doesn't perhaps resonate much with the individual customer, that when we look what's happening in other jurisdictions in terms of 6 and 9 percent rate increases that we'll still maintain, you know, competitive and affordable rates. And so we're always trying to juggle those two (2) factors, financial integrity and competitive rates, on behalf of customers, but I'm hesitant to show something that is too favourable while we're in that investment period.

But I think if we can get through that successfully, we will have produce a really good system for our customers over the long run, kind of thing. That's -- that's -- I hope I'm answering your question, at least in part.

THE CHAIRPERSON: I don't want to

belabour this point, but I think we both need to reflect about this some more. I mean, it -- it does paint -- in terms of the -- the plan that we've been talking about, the ref/ref/ref, it does paint a picture that would suggest that the ratepayers at the front end will be paying a significant rate increa -- increase going forward when there might be another alternative that is available to us, and -- and likely to represent the path that would be followed by -- by Hydro in terms of, you know, smoothing out the -- the pain to ratepayers, and likely be the path that PUB will likely favour, as well. The ones -- you know, who knows we'll be sitting here at that -- that time period.

But it seems to me that if -- if that is the approach we normally take in a -- in addressing rates both from your side and our side, that might represent a more realistic picture to present to ratepayers than -- than is currently the case.

MR. DARREN RAINKIE: Maybe, Mr. Chair, I'll -- I'll ponder whether I'll -- whether I'll volunteer an undertaking to that 'cause I -- I seriously have spent a lot of time thinking -- thinking about that.

I'll just offer one (1) observation to make sure I know -- I've said this a couple times already, but I repeat things because they're important -- is that the -- the new resources that are contemplated in any of the plans don't come into service before 2020 and '23. You know, whether it's Keeyask or -- or Gas.

The front part of this forecast that we have is real. The 3.95s are real in the next six (6) to eight (8) years. They're more a function of refurbishing existing infrastructure and reliability expenditures like Bipole III. There is no, you know, 2 percent rate increase on the Gas side. I will not be recommending to our Board 2 percent rate increases if we go down the All Gas, you know, route for instance, because there's no differential costs in that part. In fact, if I have to start writing off some of the costs of Keeyask and Conawapa under that scenario, there's going to be more pressure on my income statement and revenue requirements.

So that's why I'm focussed more towards, you know, the back end of that twenty (20) year period when the investment period is -- is winding down, if you like, and we're seeing the cash flow coming both out of Keeyask and then eventually Conawapa. I -- I think the curve would go that way.

But the first front part of this -- and

I read in the paper every second day that if we just do gas, you know, we'll have a 2 percent rate increase, and I'm not sure where that comes from. That certainly isn't inherent in the two hundred and sixteen (216) runs that we did in this -- in this proceeding, in terms of financial pro formas, so.

I -- I just -- you know, there's different time periods here, I think is -- is what I'm trying to say, and we have to keep that in mind. But can you let me ponder that a little bit more, and -- maybe there's something I can do to help the Board through this.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you, Mr. Rainkie. And as you're pondering that, to the extent that there's a smoothing of the -- the rate arch, there could be a comparable -- or there could be a -- a smoothing of the -- the rate arc for other plans as well, correct?

MR. DARREN RAINKIE: There might be a smoothing, but actually, it might go the inverse way if you look at the back end of the All Gas Plan. For instance, I think we start showing losses at the back end, so there might be, you know, an uptick actually.

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

NEEDS FOR AND ALTERNATIVES TO

REVIEW OF MANITOBA HYDRO'S

PREFERRED DEVELOPMENT PLAN

Regis Gosselin	- Chairperson
Marilyn Kapitany	- Board Member
Larry Soldier	- Board Member
Richard Bel	- Board Member
Hugh Grant	- Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

March 21, 2014

Pages 3224 to 3501

on the -- on the equation of, What can I do instead of having a rate increase, we're -- we're getting into a situation where that -- that's not as viable an option as it may have been in the past?

MR. DARREN RAINKIE: Well, we always have some flexibility, sir. It's -- it's not zero, but it's -- but -- but I -- I think, in a way, doing the asset condition assessment in a more detailed way will actually help us to better assess all these plethora of -- of assets that we have, and -- and make risk-based decisions.

So I -- I think I'm a bit more positive than your outlook on it. I -- I don't think it's zero. Certainly, we are entering a time -- and -- and, you know, you -- you read the paper, I'm sure, every day. You see other parts of the infrastructure deficit in this country that governments are grappling with in terms of how much do they tax, what assets do they repair, what assets don't -- and I -- I just philosophically see the electrical system as being an extension of the public infrastructure deficit that has to be dealt with, sir.

MR. GEORGE ORLE: Okay. In answer to questions, and I believe that they were from the -- from the Board, in answer to how to deal with -- with this consistent level of -- of rate increases over a period of time, I believed you used a �- a word -- I think it was 'smoothing'. Do -- do you recall giving that evidence?

MR. DARREN RAINKIE: Yes, sir.

MR. GEORGE ORLE: Okay. Can you tell me what you mean by 'smoothing' and what 'smoothing' is? What -- how would you go about smoothing out rates?

MR. DARREN RAINKIE: What we would do is, is that, let's say our net costs have gone up by a hundred million dollars in a year. We may choose just to increa -- increase rates at 4 percent, which would increase our -- our revenue to pay for that by $50 million.

So it's -- it's simply not overreacting to short-term cost changes, but bringing in -- that in over time, if you like. So I -- I appreciate, sir, you're kind of first time participant to this hearing.

So, there's different regulatory regimes. In many other jurisdictions they have what's called a rate-based rate of return regime, and what happens is they add up all of your costs and that equals your revenue. It's a formula driven way of setting rates, and they plot -- add on a rate of return for the bond holders and for the investors.

But we use a different approach in -- in Manitoba Hydro. We forecast out. Instead of looking at the next GR2 (phonetic) and just rigidly, you know, saying costs -- total costs equal revenues, we look out over the next ten (10) or twenty (20) years and say, How can we manage this reasonably by essentially, you know, feathering in the rate increases over time, so that -- so that customers -- I mean our view is that -- is that customers are more appreciative of smaller increments than large, lumpy ups and downs? And -- and that's really all we mean about -- by smoothing, sir.

MR. GEORGE ORLE: And to what extent can you do smoothing? At - at what level does it become something that's not possible for you to do? If you've got rate increases of 4 percent, and it comes about that given factors that you weren't anticipating, a rate increase goes up to 8 percent, gets doubled, do you have enough room in your smoothing program, or your protocol, to be able to deal with something? Is -- is there a level of increases that take you beyond your -- your smooth abilities?

MS. MARLA BOYD: I think that just made the quote of the day.

MR. DARREN RAINKIE: Well, I -- I would

say that we've been pretty successful smoothers in the last twenty (20) years, sir. In fact, if you look back to 1990 to now, our rates have actually gone up less than the rate of inflation.

So I -- I think not overreacting to short-term changes in costs, or the market, has been a very successful thing for the -- in this company. We don't -- we don't get a lot of accolades in the paper every day, sir, but I think -- I think it's worked and it can work again.

And -- and it goes back to the discussion we had with the Chair yesterday, I think, about being part of the government apparatus and borrowing through the government. And I think Mr. Bowen describes it as patient capital. He's not sitting here now. But it -- it's a little more of a -- it -- it's a -- we can be more smoothers (sic) through patient capital than we can through a -- a shareholder organization that essentially needs to -- to generate a rate of return each and every year to keep their stock price up, sir.

CONTINUED BY MR. GEORGE ORLE:

MR. GEORGE ORLE: Okay. I'm not going to repeat the -- the questions asked by Mr. Williams and Mr. Hacault, but I'm just going to try to summarize a bit. We -- we found that projections made, in terms of Wuskwatim, went off. The lessons that we learned from that were applied to Keeyask, and in the course of two (2) years we've gone off the projections.

The Chairman had asked you why there was such a range between the high and the reference, when we'd already gotten to the high part. Why, in this short period of time that we have left for that, would there still be such a wide range. Given that there's been already this -- this wide variation from what the projections are, how confident are you in -- in making projections to the year '62?

MR. DARREN RAINKIE: Well, sir, that's why we referred to the analysis as being directional. We can't put a hundred percent confidence on it, sir.

But yet we have the problem that we -- we -- we're not like a big box store, sir. If -- if there's a recession that hits, we can't close fifty (50) stores and then two (2) years later, when the economy's better, pull them back in. We're not -- we're not Best Buy, sir. We have to be here -- that's why we are smoothers. We -- we smooth through over the decades, over the century.

So, you know, we can't have a hundred

percent confidence in forecasts, but yet we have to plan over the long-term to make sure that when you flip the switch there's something at the other end, sir. And so we have to rely on the best assumptions that we have, to discern the best plan forward.

We also understand how we got to the favourable position that we -- that we have right now. The business model that has got us here, in terms of -- as I said to the Chair, building the -- building the extra room in the basement and renting it out until Manitobans need it, so.

MR. GEORGE ORLE: Yeah, I --

MR. DARREN RAINKIE: You know, Mr. Williams talked about betting the farm; I'm worried we're going to sell the farm, just because of our short-sightedness.

MR. GEORGE ORLE: I -- I'm not being critical, sir. I'm just -- in Roman times they forecast by cutting open chickens and reading their entrails. It seems to me that what we do here is we search through the entrails of consultant's reports and economist's reports, and I don't know if we get any further in terms of how -- how well we can rely upon them.

If I said to you, Would you guarantee me those results for the year '62, I -- I don't think that you'd be prepared to -- to do that. And in terms of the confidence in it, would you say that we've got a 50:50 chance of meeting those projections? Would you think that that was too far out, or would you think that that was an underestimate?

MR. DARREN RAINKIE: Sir, I'm not a statistician, so I -- I can't put a number on it. But here's my perspective, whether anybody accepts it or not, is -- is that as I said earlier, when you look back at 2006 and '07, I think nobody could foresee that the market was going down. When the market goes down, it's very hard for people to see that it's going to go back up again. It's just human nature.

But yet when we have assets that lasts for a hundred years, they'll see ten (10), fifteen (15) different business cycles, sir. I think what I am fairly confident of is that -- that over those business cycles the Preferred Development Plan that we have will weather the storm. There might be -- there might be issues from time to time, sir, but I think we can smooth over the long run and -- and make it work, but I -- I can't provide any guarantees, as you indicate, sir.

MR. GEORGE ORLE: And lastly, this will

this weekend.

But for those of you who are back on -- on Tuesday morning, we'll see you on Tuesday. Thank you very much.

(PANEL RETIRES)

--- Upon adjourning at 4:36 p.m.

Certified correct,

____

Cheryl Lavigne, Ms.

TAB 9

	Long Term Rate Increase	25% Equity Ratio	Maximum Debt	Minimum Equity	Negative Net Income	Retained Earnings at 2033/34
NFAT Plan 5 - High Keeyask Level 2 DSM	3.99% to 2031/32	2031/32	$22.447 B in 2026/27	8% in 2022-2024	Total of $638 M in 8 years during 2016-2023	$6.659 B
MH14	3.95% to 2030/31	2033/34	$24.476 B in 2028/29	10% in 2023-2027	Total of $978 M in 8 years during 2019-2026	$5.557 B
MH15	3.95% to 2028/29	2031/32	$23.495 B in 2026/27	12% in 2022-2024	Total of $58 M in 3 years during 2019-2023	$7.402 B
Coalition/MH II-19 (Based on MH16 Update with Interim)	4.14% to 2033/34	2033/34	$24.972 B in 2027/28	12% in 2026-2027	Total of $327 M in 4 years during 2024-2027	$6.385 B

REFERENCE:

PUB/MH 1-1 e)

PREAMBLE TO IR (IF ANY):

QUESTION:

Based on the MH16 Update with the August 1st, 2017 interim increase, please provide an IFF that, based on even rate increases for the years 2018/19 through 2033/34 achieves an equity ratio of 25% by 2033/34 and uses 2% per annum thereafter. (Note: This scenario differs from PUB/MH 1-1 e) in that it will use the MH 16 Update with Interim assumptions set out on page 28 of 41).

RATIONALE FOR QUESTION:

To understand the implications of Manitoba Hydro's regulatory accounting assumptions based on the new MH16 Update with Interim.

RESPONSE:

The following projected financial statements based on MH16 Update with Interim reflect annual rate increases of 4.14% from 2018/19 through 2033/34 to achieve a 25% equity ratio by 2033/34.

Sixteen years of 4.14% rate increases generate limited net income ($47 million per year on average) over the first 12 years of the forecast scenario including a 4 year period with cumulative losses of approximately $350 million following the Keeyask in-service. Levels of income that make any material contribution to debt reduction are deferred until the last 8 years of the forecast under this scenario, a period which is inherently more uncertain than the preceding period, and relies on the preceding period being at or above average water flows and other forecast assumptions. The equity ratio under this scenario deteriorates to 12% by 2026. Even without below average water conditions or drought, adverse changes in interest rates, export prices or other factors will significantly increase necessary rate increases beyond 4.14% per annum in order to restore a 25% equity to capitalization ratio by 2033/34.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	119	187	257	333	410	491	579	673	773
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 187	2 270	2 473	2 683	2 844	2 881	2 971	2 941	3 062
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	828	904	1 155	1 196	1 202	1 196	1 204
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(38)	(12)	(14)	(15)	(16)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	175
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 659	2 403	2 530	2 864	2 955	2 992	3 003	3 042
Net Income before Net Movement in Reg. Deferral	(46)	13	36	(390)	69	153	(20)	(73)	(22)	(61)	20
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	150	75	141	217	23	(121)	(71)	(110)	(25)
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	151	72	135	208	13	(132)	(74)	(112)	(28)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**151**	**72**	**135**	**208**	**13**	**(132)**	**(74)**	**(112)**	**(28)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	150	75	141	217	23	(121)	(71)	(110)	(25)
* Additional Domestic Revenue											
Percent Increase		3.36%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%
Cumulative Percent Increase		3.36%	7.64%	12.09%	16.73%	21.56%	26.59%	31.83%	37.28%	42.96%	48.88%
Financial Ratios											
Equity	16%	15%	14%	14%	14%	14%	13%	13%	13%	12%	12%
EBITDA Interest Coverage	1.51	1.54	1.65	1.59	1.65	1.73	1.64	1.57	1.63	1.62	1.69
Capital Coverage	1.53	1.40	1.37	1.22	1.47	1.73	1.45	1.37	1.36	1.28	1.39

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	880	991	1 110	1 236	1 377	1 528	1 689	1 786	1 887
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 177	3 320	3 475	3 631	3 795	3 969	4 153	4 276	4 316
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 208	1 195	1 179	1 190	1 162	1 142	1 104	1 059	1 011
Finance Income	(17)	(18)	(18)	(17)	(18)	(18)	(20)	(26)	(31)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	176	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 076	3 095	3 111	3 160	3 146	3 160	3 159	3 151	3 125
Net Income before Net Movement in Reg. Deferral	101	225	364	471	649	809	994	1 125	1 190
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	58	185	329	438	618	781	965	1 097	1 161
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	54	180	321	428	607	769	951	1 081	1 144
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**54**	**180**	**321**	**428**	**607**	**769**	**951**	**1 081**	**1 144**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	58	185	329	438	618	781	965	1 097	1 161
* Additional Domestic Revenue									
Percent Increase	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	4.14%	2.00%	2.00%
Cumulative Percent Increase	55.04%	61.45%	68.13%	75.09%	82.33%	89.88%	97.73%	101.69%	105.72%
Financial Ratios									
Equity	13%	13%	15%	16%	19%	21%	25%	29%	33%
EBITDA Interest Coverage	1.77	1.89	2.04	2.13	2.33	2.51	2.74	2.96	3.15
Capital Coverage	1.51	1.64	1.88	1.95	2.20	2.40	2.63	2.57	2.61

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 208	2 505	2 567	1 836	1 648	1 723	1 564	1 633	1 748
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 067	28 460	30 058	30 016	30 070	30 094	29 876	29 897	29 973
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 713	29 571	31 240	31 262	31 358	31 335	31 068	31 040	31 071
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 450	24 668	24 547	24 059	23 598	24 640
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 360	4 150	3 031	3 188	3 472	4 007	3 014
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 993	3 065	3 201	3 409	3 422	3 290	3 215	3 103	3 075
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(443)	(351)	(350)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 665	29 522	31 192	31 213	31 309	31 286	31 019	30 991	31 022
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 713	29 571	31 240	31 262	31 358	31 335	31 068	31 040	31 071
Net Debt	15 427	18 473	20 803	22 599	23 698	24 316	24 506	24 472	24 441	24 443	24 372
Total Equity	2 856	3 163	3 450	3 577	3 737	3 951	3 654	3 608	3 549	3 450	3 436
Equity Ratio	16%	15%	14%	14%	14%	14%	13%	13%	13%	12%	12%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 184	2 414	2 395	2 119	2 419	2 453	3 195	3 755	4 270
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 363	30 565	30 494	30 192	30 456	30 451	31 149	31 728	32 262
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	31 418	31 579	31 474	31 139	31 372	31 340	32 009	32 559	33 064
LIABILITIES AND EQUITY									
Long-Term Debt	24 972	22 595	20 102	21 362	20 926	21 363	20 680	20 859	20 543
Current and Other Liabilities	2 965	5 315	7 372	5 340	5 394	4 146	4 538	3 817	3 482
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	3 129	3 308	3 630	4 058	4 665	5 433	6 385	7 466	8 610
Accumulated Other Comprehensive Income	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)	(349)
Total Liabilities and Equity before Regulatory Deferral	31 369	31 531	31 425	31 090	31 323	31 291	31 961	32 510	33 015
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 418	31 579	31 474	31 139	31 372	31 340	32 009	32 559	33 064
Net Debt	24 212	23 948	23 525	23 023	22 327	21 471	20 421	19 300	18 116
Total Equity	3 505	3 690	4 019	4 455	5 070	5 847	6 807	7 898	9 052
Equity Ratio	13%	13%	15%	16%	19%	21%	25%	29%	33%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 173	2 179	2 381	2 591	2 752	2 843	2 958	2 929	3 049
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(952)	(966)
Interest Paid	(553)	(531)	(635)	(704)	(771)	(852)	(1 101)	(1 166)	(1 176)	(1 165)	(1 176)
Interest Received	17	5	11	22	26	19	7	4	7	7	9
	810	734	706	628	751	864	754	746	837	819	916
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 190	1 560	390	190	750	1 190
Sinking Fund Withdrawals	146	0	0	120	318	813	182	52	348	152	249
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(246)	(259)	(267)	(263)	(268)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 861	1 108	273	366	(111)	(146)	(80)	(12)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	13	51	9	(341)	123	(162)	(109)	(76)	67
Cash at Beginning of Year	943	634	488	501	552	561	221	344	182	73	(2)
Cash at End of Year	634	488	501	552	561	221	344	182	73	(2)	64

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
COALITION/MH II-19
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 164	3 306	3 461	3 617	3 781	3 955	4 138	4 262	4 301
Cash Paid to Suppliers and Employees	(980)	(995)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 086)	(1 096)
Interest Paid	(1 184)	(1 191)	(1 182)	(1 186)	(1 147)	(1 141)	(1 105)	(1 073)	(1 024)
Interest Received	15	25	28	18	14	24	27	42	45
	1 015	1 144	1 295	1 415	1 618	1 794	1 997	2 145	2 226
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	390	(10)	1 970	3 590	1 950	1 540	760	900	(30)
Sinking Fund Withdrawals	150	60	310	708	0	230	43	10	388
Sinking Fund Payment	(268)	(275)	(280)	(275)	(252)	(258)	(251)	(256)	(260)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 096)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	117	(290)	(446)	(378)	(680)	(885)	(548)	(837)	(571)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	284	(18)	(15)	132	25	(18)	510	292	622
Cash at Beginning of Year	64	349	331	316	448	473	455	965	1 257
Cash at End of Year	349	331	316	448	473	455	965	1 257	1 879

Development Plan
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
REVENUES																									
General Consumers Revenue at approved rates	1,331	1,396	1,401	1,408	1,404	1,409	1,413	1,426	1,440	1,455	1,470	1,486	1,501	1,517	1,532	1,548	1,566	1,583	1,601	1,618	1,636	1,649	1,668	1,686	1,704
Additional General Consumers Revenue	-	-	55	114	174	238	305	377	453	534	619	711	807	908	1,015	1,128	1,249	1,376	1,511	1,653	821	853	944	969	1,046
Extraprovincial	357	408	383	373	430	491	522	571	853	964	993	1,005	1,005	939	1,000	987	991	996	1,030	1,035	1,020	1,008	998	988	899
Other	14	15	15	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	21	22	22	23
Total Revenue	1,702	1,819	1,854	1,909	2,024	2,154	2,256	2,390	2,762	2,971	3,099	3,219	3,331	3,383	3,566	3,681	3,824	3,976	4,162	4,327	3,498	3,531	3,631	3,665	3,672
EXPENSES																									
Operating and Administrative	455	471	516	532	543	567	580	597	659	671	685	697	711	724	738	752	768	780	793	815	832	852	870	887	907
Finance Expense	454	462	511	542	613	694	815	841	1,132	1,247	1,249	1,266	1,268	1,265	1,230	1,210	1,172	1,136	1,150	1,110	1,072	1,070	1,107	1,124	1,133
Depreciation and Amortization	408	439	433	463	476	505	543	553	631	675	682	683	687	696	701	695	693	694	717	729	712	707	729	730	734
Water Rentals and Assessments	117	125	122	111	111	112	111	113	124	127	127	127	127	127	128	128	128	129	132	131	131	131	131	132	132
Fuel and Power Purchased	143	144	142	177	193	203	212	213	217	232	240	249	266	259	273	275	287	295	284	313	325	344	360	350	319
Capital and Other Taxes	87	95	103	113	122	132	138	143	146	146	147	149	150	151	153	155	158	161	169	170	172	174	176	178	180
Corporate Allocation	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7
Total Expenses	1,673	1,747	1,835	1,945	2,067	2,221	2,408	2,469	2,916	3,107	3,138	3,180	3,217	3,230	3,232	3,223	3,213	3,203	3,251	3,274	3,251	3,283	3,379	3,407	3,410
Non-Controlling Interest	(14)	(24)	(22)	(17)	(15)	(13)	(9)	(8)	(7)	(0)	2	6	8	8	11	14	15	19	21	22	24	26	28	29	31
Net Income	43	97	41	(19)	(27)	(55)	(142)	(71)	(147)	(136)	(41)	33	106	145	323	445	596	754	890	1,030	223	222	224	228	231
Additional General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	-25.69%	1.00%	3.22%	0.57%	2.49%
Cumulative General Consumers Revenue Percent Increase	0.00%	0.00%	3.95%	8.10%	12.41%	16.90%	21.56%	26.41%	31.45%	36.70%	42.15%	47.82%	53.72%	59.86%	66.23%	72.87%	79.76%	86.94%	94.39%	102.15%	50.21%	51.72%	56.60%	57.48%	61.40%
Debt Ratio	76	78	83	85	87	88	90	90	91	92	92	92	91	91	89	88	85	82	79	75	74	73	72	72	71
Interest Coverage Ratio	1.07	1.16	1.06	0.98	0.97	0.95	0.87	0.94	0.88	0.89	0.97	1.03	1.08	1.11	1.26	1.36	1.48	1.62	1.74	1.90	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.04	0.97	0.84	0.84	1.13	1.27	1.00	1.42	1.20	1.22	1.28	1.42	1.56	1.74	2.34	2.27	2.36	2.51	2.62	3.33	1.59	1.38	1.34	1.28	1.24

Development Plan
ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
In Millions of Dollars

K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
REVENUES																									
General Consumers Revenue at approved rates	1,723	1,742	1,762	1,782	1,802	1,822	1,844	1,866	1,888	1,910	1,932	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954	1,954
Additional General Consumers Revenue	1,117	1,162	1,224	1,295	1,339	1,448	1,434	1,556	1,652	1,718	1,813	1,944	1,887	1,981	2,022	2,032	2,128	2,167	2,208	2,260	2,283	2,310	2,355	2,397	2,485
Extraprovincial	871	847	817	802	795	788	819	791	774	785	783	740	799	814	830	846	862	878	895	912	929	947	965	983	1,002
Other	23	24	24	24	25	25	26	26	27	27	28	29	29	30	30	31	31	32	33	33	34	35	35	36	37
Total Revenue	3,735	3,775	3,827	3,903	3,961	4,083	4,123	4,239	4,341	4,441	4,556	4,666	4,670	4,779	4,836	4,863	4,976	5,032	5,089	5,159	5,200	5,245	5,309	5,370	5,478
EXPENSES																									
Operating and Administrative	927	948	970	993	1,016	1,040	1,063	1,096	1,123	1,149	1,186	1,216	1,244	1,275	1,306	1,326	1,358	1,377	1,397	1,417	1,438	1,459	1,480	1,494	1,516
Finance Expense	1,132	1,131	1,125	1,140	1,138	1,138	1,137	1,145	1,141	1,168	1,166	1,168	1,151	1,128	1,112	1,107	1,090	1,072	1,057	1,043	1,024	993	969	948	965
Depreciation and Amortization	764	765	770	782	790	856	864	882	925	944	969	994	1,009	1,097	1,123	1,118	1,198	1,239	1,277	1,323	1,346	1,387	1,436	1,483	1,529
Water Rentals and Assessments	132	132	132	131	132	132	134	133	134	135	135	134	142	145	148	151	154	156	159	162	166	169	172	175	179
Fuel and Power Purchased	327	341	368	389	412	437	435	489	518	536	590	642	611	623	635	647	659	672	685	698	711	724	738	752	766
Capital and Other Taxes	182	184	187	190	193	197	200	203	207	211	214	216	216	218	220	223	226	228	230	233	235	236	238	242	244
Corporate Allocation	7	7	7	7	7	7	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Total Expenses	3,471	3,508	3,559	3,633	3,688	3,805	3,841	3,954	4,053	4,149	4,265	4,376	4,381	4,491	4,550	4,577	4,690	4,749	4,810	4,881	4,924	4,973	5,039	5,099	5,204
Non-Controlling Interest	33	35	37	39	42	44	46	48	50	52	54	54	55	56	58	58	59	61	62	64	66	68	70	72	75
Net Income	231	232	232	231	232	234	236	237	238	240	237	237	234	232	229	228	226	222	217	214	210	204	200	199	199
Additional General Consumers Revenue Percent Increase	2.12%	1.13%	1.66%	1.89%	0.96%	2.98%	-0.95%	3.15%	2.23%	1.32%	2.04%	2.90%	-1.46%	2.45%	1.04%	0.25%	2.42%	0.95%	0.98%	1.26%	0.54%	0.63%	1.07%	0.97%	2.04%
Cumulative General Consumers Revenue Percent Increase	64.83%	66.69%	69.46%	72.65%	74.32%	79.50%	77.80%	83.40%	87.48%	89.96%	93.83%	99.46%	96.55%	101.36%	103.46%	103.96%	108.89%	110.88%	112.96%	115.64%	116.81%	118.18%	120.50%	122.63%	127.18%
Debt Ratio	70	69	69	68	67	67	66	66	65	65	64	63	63	62	61	60	60	59	58	57	56	55	54	54	53
Interest Coverage Ratio	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Capital Coverage Ratio	1.22	1.18	1.13	1.06	1.07	1.15	1.21	1.18	1.07	1.30	1.33	1.35	1.36	1.33	1.34	1.31	1.35	1.36	1.37	1.37	1.36	1.35	1.37	1.37	1.38

Development Plan
ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
ASSETS																									
Plant in Service	15,374	16,434	17,553	18,705	19,265	22,808	23,239	26,533	31,275	31,809	32,341	32,906	33,595	34,196	34,860	35,348	36,095	36,655	38,662	39,671	40,357	41,712	42,235	42,777	44,112
Accumulated Depreciation	(5,173)	(5,536)	(5,869)	(6,254)	(6,662)	(7,096)	(7,566)	(8,041)	(8,584)	(9,168)	(9,759)	(10,350)	(10,946)	(11,552)	(12,165)	(12,779)	(13,394)	(14,017)	(14,668)	(15,335)	(15,988)	(16,639)	(17,315)	(17,994)	(18,680)
Net Plant in Service	10,201	10,898	11,684	12,450	12,604	15,712	15,672	18,492	22,691	22,641	22,582	22,555	22,649	22,644	22,695	22,569	22,701	22,637	23,994	24,337	24,368	25,073	24,920	24,782	25,432
Construction in Progress	2,019	2,809	3,997	5,046	6,650	5,266	6,382	4,186	104	201	293	370	330	410	415	748	1,082	1,628	729	550	648	106	398	710	271
Current and Other Assets	1,869	1,740	1,388	1,573	1,794	2,016	1,857	2,008	2,095	1,772	1,844	2,116	2,364	2,228	2,523	2,783	2,899	3,169	3,336	4,223	4,115	3,195	3,508	3,285	3,121
Goodwill and Intangible Assets	180	165	153	140	130	121	187	212	408	398	388	381	373	366	359	351	344	337	330	322	315	308	301	293	286
Regulated Assets	231	233	259	293	370	399	428	436	428	410	389	368	348	329	311	302	267	237	214	194	178	165	155	148	145
Total Assets	14,500	15,845	17,482	19,503	21,547	23,514	24,527	25,335	25,727	25,422	25,496	25,790	26,064	25,977	26,303	26,753	27,293	28,010	28,602	29,625	29,624	28,846	29,282	29,219	29,255
LIABILITIES AND EQUITY																									
Long Term Debt	9,272	11,144	13,018	14,842	16,962	18,738	20,435	21,004	21,533	21,485	22,088	22,490	22,243	22,446	22,447	22,388	22,139	21,642	22,031	21,804	19,807	18,609	18,519	17,921	17,373
Current and Other Liabilities	2,183	1,651	1,775	1,995	2,013	2,286	1,762	2,091	2,123	2,030	1,557	1,412	1,825	1,388	1,387	1,449	1,641	2,097	1,407	1,625	3,396	3,592	3,891	4,195	4,545
Contributions in Aid of Construction	314	314	315	315	316	322	324	327	330	333	336	339	341	344	346	348	351	353	356	358	361	364	366	369	372
Retained Earnings	2,432	2,529	2,531	2,512	2,485	2,430	2,288	2,217	2,069	1,934	1,893	1,926	2,032	2,177	2,500	2,945	3,540	4,295	5,185	6,215	6,437	6,659	6,883	7,111	7,342
Accumulated Other Comprehensive Income	299	207	(157)	(162)	(228)	(262)	(282)	(304)	(329)	(360)	(378)	(378)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)
Total Liabilities and Equity	14,500	15,845	17,482	19,503	21,547	23,514	24,527	25,335	25,727	25,422	25,496	25,790	26,064	25,977	26,303	26,753	27,293	28,010	28,602	29,625	29,624	28,846	29,282	29,219	29,255

Development Plan
ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
In Millions of Dollars

K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
ASSETS													
Plant in Service	44,697	45,304	46,309	46,975	49,346	50,025	50,735	52,800	54,070	54,880	56,316	57,017	59,763
Accumulated Depreciation	(19,398)	(20,120)	(20,849)	(21,591)	(22,341)	(23,159)	(23,986)	(24,830)	(25,720)	(26,628)	(27,563)	(28,524)	(29,500)
Net Plant in Service	25,299	25,183	25,460	25,384	27,005	26,866	26,749	27,970	28,350	28,252	28,753	28,493	30,263
Construction in Progress	628	1,009	1,053	1,512	275	865	1,465	574	760	1,475	1,239	1,690	139
Current and Other Assets	3,200	3,194	3,235	3,258	3,279	3,183	3,291	3,417	3,504	3,557	3,930	4,188	3,679
Goodwill and Intangible Assets	279	272	264	257	250	243	235	228	221	214	207	199	192
Regulated Assets	138	127	116	107	99	92	87	83	81	80	81	82	83
Total Assets	29,543	29,784	30,128	30,518	30,908	31,249	31,828	32,272	32,916	33,579	34,210	34,652	34,356
LIABILITIES AND EQUITY													
Long Term Debt	18,175	19,077	19,229	19,979	20,078	20,627	21,225	21,424	22,022	22,420	22,819	22,492	22,090
Current and Other Liabilities	3,798	2,902	2,860	2,265	2,320	1,877	1,617	1,622	1,427	1,448	1,440	1,969	1,837
Contributions in Aid of Construction	375	378	381	384	387	390	393	396	400	403	407	410	414
Retained Earnings	7,573	7,805	8,037	8,268	8,500	8,733	8,970	9,207	9,444	9,684	9,922	10,158	10,392
Accumulated Other Comprehensive Income	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)
Total Liabilities and Equity	29,543	29,784	30,128	30,518	30,908	31,249	31,828	32,272	32,916	33,579	34,210	34,652	34,356

For the year ended March 31	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
ASSETS												
Plant in Service	61,000	62,376	63,760	65,178	66,715	68,387	69,775	71,153	72,596	74,036	75,538	77,659
Accumulated Depreciation	(30,564)	(31,654)	(32,750)	(33,925)	(35,138)	(36,387)	(37,680)	(38,995)	(40,350)	(41,751)	(43,197)	(44,688)
Net Plant in Service	30,435	30,722	31,010	31,253	31,578	32,001	32,095	32,157	32,246	32,286	32,341	32,971
Construction in Progress	160	168	215	304	241	26	29	31	34	222	496	(89)
Current and Other Assets	3,325	3,273	3,131	2,437	1,825	1,631	1,571	1,513	1,217	1,070	1,142	1,295
Goodwill and Intangible Assets	185	178	171	163	156	149	142	134	127	120	113	106
Regulated Assets	85	86	99	111	121	131	138	145	150	153	154	156
Total Assets	34,191	34,426	34,625	34,268	33,922	33,938	33,975	33,981	33,774	33,851	34,246	34,438
LIABILITIES AND EQUITY												
Long Term Debt	22,090	22,039	21,039	19,038	18,438	18,037	17,229	17,829	18,103	18,102	18,902	18,852
Current and Other Liabilities	1,437	1,490	2,462	3,880	3,912	4,112	4,743	3,940	3,254	3,132	2,528	2,572
Contributions in Aid of Construction	418	421	421	421	421	421	421	421	421	421	421	421
Retained Earnings	10,624	10,853	11,080	11,306	11,528	11,745	11,959	12,169	12,372	12,573	12,771	12,970
Accumulated Other Comprehensive Income	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)
Total Liabilities and Equity	34,191	34,426	34,625	34,268	33,922	33,938	33,975	33,981	33,774	33,851	34,246	34,438

Development Plan K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY
ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

For the year ended March 31	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
OPERATING ACTIVITIES																									
Cash Receipts from Customers	1,692	1,819	1,854	1,909	2,024	2,154	2,256	2,390	2,762	2,971	3,099	3,219	3,331	3,383	3,566	3,681	3,824	3,976	4,162	4,327	3,498	3,531	3,631	3,665	3,672
Cash Paid to Suppliers and Employees	(782)	(810)	(857)	(905)	(940)	(983)	(1,009)	(1,031)	(1,108)	(1,137)	(1,158)	(1,178)	(1,206)	(1,212)	(1,240)	(1,255)	(1,282)	(1,303)	(1,312)	(1,359)	(1,386)	(1,420)	(1,451)	(1,457)	(1,442)
Interest Paid	(467)	(483)	(527)	(577)	(633)	(736)	(866)	(885)	(1,187)	(1,311)	(1,285)	(1,282)	(1,297)	(1,301)	(1,282)	(1,276)	(1,252)	(1,214)	(1,244)	(1,175)	(1,152)	(1,157)	(1,187)	(1,215)	(1,227)
Interest Received	28	17	24	25	30	37	40	38	35	32	18	19	27	32	42	55	69	73	81	56	70	73	77	76	82
Cash from Operating Activities	471	542	495	453	481	472	422	512	502	555	675	778	855	902	1,086	1,206	1,359	1,532	1,686	1,848	1,029	1,027	1,069	1,069	1,086
FINANCING ACTIVITIES																									
Proceeds from Long Term Debt	836	1,970	2,160	2,190	2,580	2,590	1,980	1,190	1,190	390	560	390	190	180	(10)	(10)	(10)	160	390	(10)	(40)	930	2,320	2,180	2,510
Sinking Fund Withdrawals	129	410	103	22	-	22	412	193	274	670	155	-	-	343	-	-	60	250	700	13	230	200	-	304	310
Retirement of Long Term Debt	(119)	(825)	(177)	(312)	(347)	(530)	(825)	(305)	(633)	(673)	(431)	-	-	(450)	-	-	(60)	(220)	(700)	(13)	(200)	(1,950)	(2,130)	(2,481)	(2,730)
Other Financing Activities	(42)	(7)	(21)	(22)	(21)	(17)	(28)	(17)	(39)	(14)	(4)	(4)	(4)	(5)	(4)	(4)	(2)	(2)	(1)	(20)	(20)	(21)	(21)	(22)	(19)
Cash from Financing Activities	804	1,548	2,066	1,878	2,213	2,065	1,539	1,061	793	373	279	386	186	69	(14)	(14)	(12)	188	389	(30)	(30)	(841)	169	(19)	71
INVESTING ACTIVITIES																									
Property Plant and Equipment net of contributions	(1,311)	(1,968)	(2,324)	(2,292)	(2,294)	(2,242)	(1,710)	(1,311)	(1,063)	(680)	(672)	(692)	(702)	(732)	(719)	(872)	(1,104)	(1,128)	(1,129)	(853)	(805)	(837)	(838)	(877)	(920)
Sinking Fund Payment	(107)	(218)	(121)	(184)	(171)	(225)	(225)	(229)	(246)	(345)	(230)	(234)	(247)	(259)	(252)	(262)	(272)	(280)	(280)	(261)	(270)	(270)	(264)	(275)	(272)
Other Investing Activities	(17)	(16)	(21)	(20)	(32)	(42)	(28)	(28)	(33)	(38)	(29)	(32)	(25)	(25)	(28)	(26)	(26)	(26)	(26)	(26)	(27)	(27)	(27)	(27)	(27)
Cash from Investing Activities	(1,436)	(2,202)	(2,467)	(2,496)	(2,497)	(2,508)	(1,963)	(1,568)	(1,341)	(1,063)	(931)	(959)	(973)	(1,016)	(999)	(1,160)	(1,402)	(1,434)	(1,435)	(1,140)	(1,102)	(1,133)	(1,129)	(1,180)	(1,219)
Net Increase (Decrease) in Cash	(160)	(112)	93	(165)	197	29	(2)	5	(47)	(135)	24	206	67	(46)	73	32	(56)	286	640	678	(103)	(947)	109	(129)	(63)
Cash at Beginning of Year	43	(118)	(229)	(136)	(301)	(104)	(75)	(77)	(73)	(119)	(255)	(231)	(25)	42	(4)	69	101	45	331	971	1,649	1,546	599	709	580
Cash at End of Year	(118)	(229)	(136)	(301)	(104)	(75)	(77)	(73)	(119)	(255)	(231)	(25)	42	(4)	69	101	45	331	971	1,649	1,546	599	709	580	517

Development Plan
ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
In Millions of Dollars

K19/GAS/750MW (5) - LEVEL 2 DSM - HIGH KEEYASK - MAIN SUBMISSION RATE METHODOLOGY

For the year ended March 31	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
OPERATING ACTIVITIES																									
Cash Receipts from Customers	3,735	3,775	3,827	3,903	3,961	4,083	4,123	4,239	4,341	4,441	4,556	4,666	4,670	4,779	4,836	4,863	4,976	5,032	5,089	5,159	5,200	5,245	5,309	5,370	5,478
Cash Paid to Suppliers and Employees	(1,468)	(1,500)	(1,545)	(1,585)	(1,628)	(1,673)	(1,693)	(1,774)	(1,825)	(1,868)	(1,952)	(2,026)	(2,021)	(2,056)	(2,094)	(2,132)	(2,169)	(2,206)	(2,244)	(2,282)	(2,321)	(2,360)	(2,401)	(2,435)	(2,478)
Interest Paid	(1,229)	(1,234)	(1,233)	(1,256)	(1,263)	(1,270)	(1,272)	(1,300)	(1,309)	(1,354)	(1,364)	(1,382)	(1,382)	(1,336)	(1,321)	(1,326)	(1,321)	(1,260)	(1,230)	(1,217)	(1,199)	(1,187)	(1,149)	(1,132)	(1,146)
Interest Received	88	95	105	110	118	126	135	149	162	180	200	210	216	202	208	217	219	178	175	175	181	185	185	182	191
Cash from Operating Activities	1,126	1,136	1,154	1,172	1,188	1,267	1,292	1,314	1,369	1,400	1,440	1,469	1,482	1,589	1,630	1,622	1,704	1,744	1,790	1,836	1,861	1,883	1,944	1,985	2,045
FINANCING ACTIVITIES																									
Proceeds from Long Term Debt	3,150	2,360	1,550	1,570	980	920	770	370	560	360	370	170	(70)	(30)	(40)	(60)	310	1,490	2,160	2,280	2,930	1,930	1,530	1,750	950
Sinking Fund Withdrawals	143	100	188	144	145	146	50	-	100	-	-	-	425	200	-	50	542	593	200	186	7	167	298	-	-
Retirement of Long Term Debt	(3,110)	(2,380)	(1,460)	(1,440)	(840)	(840)	(440)	(190)	(180)	10	10	10	(485)	(390)	10	(10)	(930)	(2,320)	(2,180)	(2,510)	(3,157)	(2,360)	(1,675)	(1,570)	(980)
Other Financing Activities	(20)	(20)	(21)	(22)	(30)	(32)	(53)	(32)	(33)	(38)	(34)	(34)	(35)	(36)	(36)	(37)	(38)	(39)	(39)	(41)	(74)	(82)	(84)	(86)	(102)
Cash from Financing Activities	163	60	257	251	255	195	327	148	447	332	346	146	(165)	(256)	(66)	(57)	(116)	(276)	141	(84)	(294)	(344)	69	94	(132)
INVESTING ACTIVITIES																									
Property Plant and Equipment net of contributions	(960)	(998)	(1,060)	(1,136)	(1,143)	(1,280)	(1,320)	(1,185)	(1,467)	(1,537)	(1,212)	(1,163)	(1,207)	(1,271)	(1,396)	(1,443)	(1,520)	(1,488)	(1,471)	(1,404)	(1,394)	(1,460)	(1,643)	(1,789)	(1,552)
Sinking Fund Payment	(269)	(274)	(282)	(285)	(293)	(300)	(308)	(322)	(337)	(350)	(182)	(191)	(201)	(193)	(191)	(198)	(204)	(185)	(164)	(161)	(157)	(162)	(160)	(153)	(161)
Other Investing Activities	(28)	(28)	(28)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)	(30)	(30)	(31)	(30)	(15)	(15)	(14)	(14)	(13)	(37)	(37)	(37)	(38)	(38)
Cash from Investing Activities	(1,257)	(1,299)	(1,369)	(1,449)	(1,464)	(1,608)	(1,657)	(1,536)	(1,834)	(1,917)	(1,424)	(1,384)	(1,439)	(1,494)	(1,618)	(1,657)	(1,738)	(1,687)	(1,648)	(1,578)	(1,588)	(1,659)	(1,841)	(1,979)	(1,751)
Net Increase (Decrease) in Cash	33	(103)	42	(26)	(22)	(147)	(38)	(74)	(18)	(184)	362	230	(122)	(161)	(54)	(92)	(150)	(218)	283	173	(21)	(120)	172	99	162
Cash at Beginning of Year	517	549	446	489	463	441	294	257	182	164	(20)	342	572	450	290	235	143	(6)	(225)	58	231	211	91	263	362
Cash at End of Year	549	446	489	463	441	294	257	182	164	(20)	342	572	450	290	235	143	(6)	(225)	58	231	211	91	263	362	523

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
REVENUES										
General Consumers										
GCR at Approved Rates	1 437	1 454	1 460	1 483	1 490	1 501	1 506	1 513	1 525	1 538
Proposed Rate Increases	0	57	118	183	250	321	394	471	554	641
BPIII Reserve Account	(30)	(32)	(34)	(36)	(11)	0	0	0	0	0
Extraprovincial	409	434	450	457	479	514	817	943	959	987
Other	15	14	14	14	15	15	15	15	16	16
	1 831	1 928	2 008	2 101	2 222	2 352	2 732	2 944	3 054	3 182
EXPENSES										
Operating and Administrative	486	542	552	557	571	585	601	607	619	631
Finance Expense	495	510	548	581	752	887	1 194	1 326	1 334	1 349
Depreciation and Amortization	405	401	422	445	521	524	613	667	736	752
Water Rentals and Assessments	124	123	112	112	112	114	124	127	132	132
Fuel and Power Purchased	134	130	191	202	207	205	234	263	257	267
Capital and Other Taxes	99	107	121	134	143	144	145	151	150	161
Corporate Allocation	9	8	8	8	8	8	8	8	8	8
Other Expenses	2	2	2	2	2	3	3	3	3	3
	1 754	1 824	1 956	2 044	2 317	2 471	2 920	3 150	3 239	3 304
Non-controlling Interest	25	12	8	7	5	4	10	0	(1)	(3)
Net Income	102	115	59	64	(90)	(116)	(178)	(206)	(187)	(124)
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	22%	18%	16%	15%	14%	13%	12%	11%	10%	10%
Interest Coverage	1.16	1.16	1.07	1.06	0.92	0.91	0.86	0.85	0.86	0.91
Capital Coverage	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22

ELECTRIC OPERATIONS (MH14)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
REVENUES										
General Consumers										
GCR at Approved Rates	1 551	1 565	1 580	1 593	1 607	1 624	1 641	1 659	1 677	1 696
Proposed Rate Increases	734	832	935	1 043	1 157	1 280	1 409	1 486	1 566	1 649
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	996	928	944	921	920	927	911	901	883	884
Other	16	17	17	18	18	18	19	19	19	20
	3 298	3 342	3 475	3 575	3 702	3 849	3 980	4 065	4 145	4 248
EXPENSES										
Operating and Administrative	644	657	669	683	697	706	719	733	748	763
Finance Expense	1 351	1 348	1 338	1 337	1 321	1 301	1 263	1 197	1 161	1 116
Depreciation and Amortization	767	780	791	804	811	820	831	842	857	873
Water Rentals and Assessments	133	132	133	133	134	134	135	135	136	137
Fuel and Power Purchased	278	275	283	283	291	302	307	317	320	333
Capital and Other Taxes	162	163	164	165	166	167	168	170	173	174
Corporate Allocation	8	8	8	8	8	6	5	6	5	5
Other Expenses	3	2	2	2	2	2	3	3	3	3
	3 346	3 365	3 388	3 415	3 430	3 439	3 432	3 403	3 403	3 404
Non-controlling Interest	(5)	(2)	(3)	(5)	(6)	(10)	(12)	(15)	(17)	(19)
Net Income	(53)	(24)	84	155	266	400	536	647	725	826
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%
Financial Ratios										
Equity	10%	10%	10%	11%	12%	14%	16%	19%	22%	25%
Interest Coverage	0.96	0.98	1.06	1.11	1.20	1.30	1.42	1.53	1.61	1.71
Capital Coverage	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
ASSETS										
Plant in Service	17 163	17 912	19 127	19 988	24 957	28 333	33 202	33 846	34 478	35 142
Accumulated Depreciation	(5 676)	(6 012)	(6 392)	(6 795)	(7 270)	(7 798)	(8 403)	(9 055)	(9 721)	(10 401)
Net Plant in Service	11 487	11 900	12 735	13 193	17 687	20 535	24 800	24 791	24 757	24 741
Construction in Progress	3 257	4 932	6 755	8 982	6 040	3 939	169	185	241	263
Current and Other Assets	1 798	1 570	1 822	2 268	2 295	2 598	2 727	2 167	2 238	2 442
Goodwill and Intangible Assets	198	186	175	166	166	177	168	152	137	121
Regulated Assets	254	278	313	352	396	420	434	431	416	398
	16 993	18 866	21 801	24 961	26 585	27 668	28 299	27 727	27 788	27 965
LIABILITIES AND EQUITY										
Long-Term Debt	11 705	13 808	16 681	18 689	21 177	21 906	22 792	22 955	23 250	23 441
Current and Other Liabilities	2 016	2 151	2 097	3 069	2 214	2 654	2 604	2 104	2 028	2 101
Contributions in Aid of Construction	412	446	480	514	549	583	618	654	690	727
BPIII Reserve Account	49	81	115	151	162	108	54	-	-	-
Retained Earnings	2 717	2 778	2 837	2 902	2 812	2 696	2 518	2 312	2 126	2 001
Accumulated Other Comprehensive Income	94	(399)	(409)	(363)	(328)	(278)	(287)	(298)	(305)	(305)
	16 993	18 866	21 801	24 961	26 585	27 668	28 299	27 727	27 788	27 965

ELECTRIC OPERATIONS (MH14)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
ASSETS										
Plant in Service	35 822	36 544	37 410	38 124	38 859	39 555	40 294	41 050	41 823	42 952
Accumulated Depreciation	(11 096)	(11 807)	(12 532)	(13 274)	(14 030)	(14 800)	(15 585)	(16 384)	(17 200)	(18 031)
Net Plant in Service	24 725	24 737	24 878	24 849	24 828	24 754	24 710	24 666	24 623	24 921
Construction in Progress	322	344	225	254	277	323	365	402	465	255
Current and Other Assets	2 387	2 536	2 801	3 049	3 421	3 773	3 629	4 288	4 963	5 703
Goodwill and Intangible Assets	107	93	80	68	57	45	34	23	11	(0)
Regulated Assets	374	353	333	313	300	295	293	296	304	311
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189
LIABILITIES AND EQUITY										
Long-Term Debt	23 395	24 198	24 401	24 343	24 476	23 749	23 739	23 743	23 737	23 381
Current and Other Liabilities	2 112	1 443	1 373	1 456	1 372	1 968	1 243	1 199	1 132	1 446
Contributions in Aid of Construction	764	802	839	876	914	952	990	1 029	1 069	1 109
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	1 948	1 924	2 007	2 161	2 427	2 826	3 361	4 008	4 732	5 557
Accumulated Other Comprehensive Income	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)	(304)
	27 914	28 063	28 316	28 533	28 884	29 191	29 030	29 675	30 366	31 189

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 859	1 958	2 039	2 134	2 231	2 349	2 729	2 941	3 051	3 180
Cash Paid to Suppliers and Employees	(803)	(871)	(942)	(973)	(1 000)	(1 015)	(1 069)	(1 099)	(1 124)	(1 155)
Interest Paid	(511)	(514)	(547)	(593)	(784)	(928)	(1 222)	(1 349)	(1 329)	(1 341)
Interest Received	13	15	21	30	35	34	31	28	15	16
	558	587	571	598	482	441	469	522	613	699
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1 953	2 390	3 190	3 200	2 790	1 600	1 590	600	560	580
Sinking Fund Withdrawals	110	21	-	7	448	204	294	716	165	27
Retirement of Long-Term Debt	(800)	(312)	(334)	(330)	(1 195)	(315)	(850)	(718)	(441)	(290)
Other	(45)	(22)	(20)	(20)	(30)	(19)	(101)	(25)	(41)	(32)
	1 218	2 077	2 836	2 857	2 013	1 470	933	573	243	285
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(1 900)	(2 518)	(3 134)	(3 244)	(2 253)	(1 550)	(1 010)	(756)	(698)	(697)
Sinking Fund Payment	(125)	(202)	(168)	(243)	(241)	(245)	(262)	(358)	(252)	(258)
Other	(21)	(21)	(21)	(21)	(21)	(35)	(30)	(30)	(30)	(30)
	(2 046)	(2 742)	(3 323)	(3 508)	(2 516)	(1 830)	(1 302)	(1 144)	(980)	(986)
Net Increase (Decrease) in Cash	(270)	(78)	84	(53)	(21)	80	100	(50)	(124)	(2)
Cash at Beginning of Year	133	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)
Cash at End of Year	(137)	(214)	(130)	(183)	(204)	(124)	(24)	(73)	(198)	(200)

ELECTRIC OPERATIONS (MH14)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 295	3 340	3 472	3 572	3 699	3 846	3 977	4 062	4 142	4 245
Cash Paid to Suppliers and Employees	(1 179)	(1 189)	(1 211)	(1 225)	(1 247)	(1 269)	(1 288)	(1 314)	(1 334)	(1 363)
Interest Paid	(1 348)	(1 353)	(1 354)	(1 371)	(1 368)	(1 360)	(1 341)	(1 250)	(1 230)	(1 200)
Interest Received	19	21	35	49	62	71	84	63	78	92
	787	818	943	1 024	1 146	1 288	1 432	1 561	1 655	1 775
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	390	780	190	(10)	180	(30)	(20)	(20)	(40)	(30)
Sinking Fund Withdrawals	297	103	-	-	60	100	700	13	30	-
Retirement of Long-Term Debt	(402)	(450)	-	-	(60)	(70)	(700)	(13)	-	20
Other	(31)	(30)	(29)	(27)	(25)	(22)	(21)	(38)	(37)	(36)
	254	403	161	(37)	155	(22)	(41)	(58)	(47)	(46)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(744)	(751)	(752)	(745)	(762)	(748)	(787)	(800)	(846)	(928)
Sinking Fund Payment	(271)	(270)	(278)	(291)	(303)	(313)	(320)	(298)	(309)	(320)
Other	(30)	(31)	(25)	(26)	(26)	(26)	(26)	(26)	(27)	(27)
	(1 045)	(1 051)	(1 056)	(1 062)	(1 091)	(1 087)	(1 134)	(1 125)	(1 182)	(1 275)
Net Increase (Decrease) in Cash	(4)	170	48	(75)	210	179	257	378	427	454
Cash at Beginning of Year	(200)	(204)	(34)	14	(61)	149	328	585	963	1 390
Cash at End of Year	(204)	(34)	14	(61)	149	328	585	963	1 390	1 844

Proposed Integrated Financial Forecast (IFF15)

2015/16 - 2034/35

Financial Planning
Finance & Regulatory

Manitoba Hydro

19.0 ELECTRIC OPERATIONS FINANCIAL FORECAST (MH15)

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES										
General Consumers										
at approved rates	1 517	1 556	1 553	1 552	1 542	1 566	1 570	1 583	1 596	1 610
additional*	0	61	125	191	258	335	411	493	580	672
BPIII Reserve Account	(54)	(67)	(69)	(21)	0	0	0	0	0	0
Extraprovincial	395	406	449	474	548	825	966	979	983	986
Other	29	28	28	29	116	118	119	32	32	33
	1 887	1 985	2 086	2 225	2 465	2 844	3 066	3 087	3 191	3 301
EXPENSES										
Operating and Administrative	542	552	557	571	585	601	607	619	631	644
Finance Expense	566	588	579	715	823	1 079	1 188	1 180	1 181	1 176
Depreciation and Amortization	410	426	450	535	589	690	742	762	781	800
Water Rentals and Assessments	126	116	113	113	115	124	127	132	132	132
Fuel and Power Purchased	120	151	182	180	174	206	228	227	230	242
Capital and Other Taxes	107	122	136	145	146	149	157	157	163	165
Other Expenses	2	2	2	2	2	2	2	3	3	3
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1 882	1 965	2 027	2 269	2 443	2 860	3 059	3 087	3 129	3 169
Non-controlling Interest	10	9	4	3	0	2	(1)	(3)	(5)	(3)
Net Income	15	29	63	(41)	21	(13)	6	(4)	56	129
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	15%	14%	14%	13%	13%	13%	12%	12%	12%	13%
Interest Coverage	1.02	1.03	1.06	0.96	1.02	0.99	1.00	1.00	1.05	1.11
EBITDA Interest Coverage	1.57	1.52	1.52	1.46	1.54	1.57	1.62	1.63	1.70	1.78
Capital Coverage	0.98	0.98	1.21	1.05	1.06	1.13	1.32	1.49	1.59	1.60

* Approved financial targets are for consolidated operations only but financial ratios have been provided for electric operations for information purposes.

ELECTRIC OPERATIONS (MH15)
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES										
General Consumers										
at approved rates	1 626	1 641	1 655	1 669	1 683	1 706	1 734	1 763	1 795	1 831
additional*	769	872	979	1 093	1 158	1 231	1 311	1 395	1 485	1 581
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	884	903	875	886	894	863	835	807	781	787
Other	34	35	35	36	37	38	38	39	40	40
	3 313	3 450	3 545	3 684	3 772	3 838	3 919	4 004	4 101	4 240
EXPENSES										
Operating and Administrative	657	669	683	697	706	719	733	748	763	778
Finance Expense	1 167	1 157	1 134	1 113	1 087	1 055	993	963	929	893
Depreciation and Amortization	820	838	854	867	880	893	906	921	941	963
Water Rentals and Assessments	132	133	133	134	134	135	135	135	136	136
Fuel and Power Purchased	231	241	239	249	257	255	263	271	281	318
Capital and Other Taxes	166	167	168	169	171	172	173	175	177	179
Other Expenses	3	3	3	3	3	3	3	3	3	3
Corporate Allocation	8	8	8	8	5	3	3	3	3	3
	3 183	3 215	3 222	3 239	3 243	3 234	3 211	3 219	3 234	3 274
Non-controlling Interest	(1)	(2)	(4)	(5)	(8)	(11)	(14)	(16)	(19)	(20)
Net Income	129	232	319	439	520	592	694	769	849	946
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	68.78%	72.15%	75.60%	79.11%	82.69%	86.35%
Financial Ratios										
Equity	13%	14%	16%	17%	20%	22%	25%	28%	31%	35%
Interest Coverage	1.11	1.20	1.28	1.39	1.47	1.56	1.69	1.79	1.90	2.04
EBITDA Interest Coverage	1.81	1.92	2.03	2.16	2.28	2.40	2.60	2.74	2.91	3.11
Capital Coverage	1.61	1.78	1.91	2.03	2.22	2.20	2.35	2.45	2.54	2.45

* Approved financial targets are for consolidated operations only but financial ratios have been provided for electric operations for information purposes.

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ASSETS										
Plant in Service	12 702	13 384	14 151	19 119	22 740	27 521	28 289	28 981	29 672	30 356
Accumulated Depreciation	(697)	(1 056)	(1 428)	(1 871)	(2 352)	(2 926)	(3 543)	(4 171)	(4 818)	(5 470)
Net Plant in Service	12 005	12 328	12 723	17 248	20 388	24 595	24 746	24 810	24 855	24 886
Construction in Progress	4 880	7 548	9 242	6 227	4 001	192	242	223	179	181
Current and Other Assets	2 392	2 654	2 914	3 086	3 093	2 820	2 015	2 387	2 649	2 637
Goodwill and Intangible Assets	237	287	396	563	675	952	916	881	846	813
Regulated Assets	277	298	753	787	811	831	850	839	817	796
	19 791	23 115	26 028	27 911	28 967	29 390	28 768	29 140	29 347	29 313
LIABILITIES AND EQUITY										
Long-Term Debt	14 487	17 586	19 499	21 929	22 429	22 808	22 763	23 257	23 237	22 725
Current and Other Liabilities	2 889	3 005	3 586	2 965	3 502	3 550	3 022	2 888	3 043	3 378
Provisions	53	52	52	52	53	53	53	54	54	54
Deferred Revenue	418	440	460	480	513	526	538	551	565	578
BPIII Reserve Account	103	170	239	260	174	87	-	-	-	-
Retained Earnings	2 612	2 641	2 703	2 663	2 684	2 671	2 677	2 673	2 729	2 858
Accumulated Other Comprehensive Income	(771)	(780)	(512)	(438)	(388)	(305)	(285)	(282)	(282)	(281)
	19 791	23 115	26 028	27 911	28 967	29 390	28 768	29 140	29 347	29 313

ELECTRIC OPERATIONS (MH15)
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS										
Plant in Service	31 081	31 760	32 474	33 199	33 909	34 645	35 389	36 152	36 984	37 813
Accumulated Depreciation	(6 141)	(6 818)	(7 513)	(8 216)	(8 936)	(9 677)	(10 405)	(11 151)	(11 930)	(12 671)
Net Plant in Service	24 941	24 942	24 961	24 983	24 973	24 968	24 984	25 001	25 054	25 142
Construction in Progress	146	172	162	152	140	153	141	138	143	259
Current and Other Assets	2 690	3 198	3 608	4 069	4 601	4 579	5 349	6 155	7 034	7 854
Goodwill and Intangible Assets	781	749	717	686	655	624	593	563	532	501
Regulated Assets	778	761	750	747	745	748	755	763	774	786
	29 335	29 821	30 198	30 638	31 114	31 072	31 822	32 620	33 537	34 542
LIABILITIES AND EQUITY										
Long-Term Debt	23 293	23 495	23 437	23 360	22 632	22 622	22 625	22 619	22 622	20 941
Current and Other Liabilities	2 688	2 726	2 829	2 895	3 565	2 927	2 966	2 987	3 038	4 763
Provisions	54	54	54	54	54	54	54	54	54	54
Deferred Revenue	592	607	619	632	646	659	673	687	702	717
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2 987	3 219	3 538	3 977	4 497	5 089	5 784	6 553	7 402	8 348
Accumulated Other Comprehensive Income	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)
	29 335	29 821	30 198	30 638	31 114	31 072	31 822	32 620	33 537	34 542

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPERATING ACTIVITIES										
Cash Receipts from Customers	1 974	2 041	2 145	2 235	2 367	2 745	2 966	3 074	3 178	3 288
Cash Paid to Suppliers and Employees	(855)	(898)	(944)	(963)	(975)	(1 034)	(1 066)	(1 088)	(1 109)	(1 134)
Interest Paid	(561)	(547)	(551)	(716)	(831)	(1 085)	(1 184)	(1 155)	(1 163)	(1 163)
Interest Received	9	3	11	19	22	19	17	2	2	5
	567	599	662	576	583	646	734	834	908	997
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	2 457	3 370	2 970	2 800	1 390	1 190	400	780	380	190
Sinking Fund Withdrawals	114	62	-	244	194	296	754	174	14	293
Retirement of Long-Term Debt	(361)	(320)	(330)	(984)	(329)	(865)	(757)	(450)	(290)	(412)
Other	82	(34)	(35)	(46)	(35)	(116)	(40)	(58)	(49)	(50)
	2 292	3 078	2 605	2 014	1 220	505	356	446	54	22
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2 614)	(3 437)	(3 085)	(2 211)	(1 645)	(1 149)	(829)	(730)	(694)	(745)
Sinking Fund Payment	(133)	(174)	(256)	(220)	(247)	(271)	(328)	(200)	(246)	(259)
Other	(21)	(21)	(21)	(21)	(21)	(32)	(31)	(32)	(32)	(32)
	(2 768)	(3 632)	(3 362)	(2 452)	(1 912)	(1 452)	(1 188)	(962)	(972)	(1 036)
Net Increase (Decrease) in Cash	91	44	(95)	138	(110)	(301)	(98)	318	(10)	(17)
Cash at Beginning of Year	482	573	617	521	659	550	248	150	468	458
Cash at End of Year	573	617	521	659	550	248	150	468	458	440

ELECTRIC OPERATIONS (MH15)
PROJECTED CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
OPERATING ACTIVITIES										
Cash Receipts from Customers	3 300	3 436	3 531	3 670	3 758	3 823	3 904	3 989	4 086	4 225
Cash Paid to Suppliers and Employees	(1 136)	(1 159)	(1 171)	(1 195)	(1 214)	(1 225)	(1 249)	(1 272)	(1 299)	(1 351)
Interest Paid	(1 163)	(1 154)	(1 153)	(1 147)	(1 128)	(1 110)	(1 027)	(1 009)	(988)	(966)
Interest Received	6	14	30	42	50	61	42	54	66	79
	1 007	1 137	1 237	1 370	1 466	1 549	1 671	1 762	1 866	1 987
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	550	190	(10)	(10)	(30)	(10)	(10)	(30)	(30)	(50)
Sinking Fund Withdrawals	98	-	-	60	110	700	13	30	-	10
Retirement of Long-Term Debt	(715)	-	-	(60)	(80)	(700)	(13)	-	20	20
Other	(47)	(46)	(45)	(44)	(42)	(42)	(41)	(39)	(36)	(37)
	(114)	144	(55)	(54)	(42)	(52)	(51)	(39)	(46)	(57)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(756)	(782)	(787)	(810)	(788)	(836)	(849)	(874)	(941)	(1 108)
Sinking Fund Payment	(255)	(260)	(272)	(283)	(292)	(298)	(275)	(285)	(295)	(307)
Other	(32)	(33)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)
	(1 043)	(1 075)	(1 087)	(1 121)	(1 108)	(1 162)	(1 153)	(1 189)	(1 265)	(1 445)
Net Increase (Decrease) in Cash	(150)	206	95	195	316	335	467	534	555	485
Cash at Beginning of Year	440	291	497	592	787	1 103	1 437	1 905	2 439	2 994
Cash at End of Year	291	497	592	787	1 103	1 437	1 905	2 439	2 994	3 479

TAB 10

REFERENCE:

Tab 2, Page 29

PREAMBLE TO IR (IF ANY):

Manitoba Hydro notes that "In Manitoba Hydro's view, a financial plan that returns the Corporation to a 25% equity level over almost 20 years is not credible as a commitment to being a self-supporting entity."

The PUB, in the report on NFAT (page 28-19), noted as follows:

"Manitoba Hydro's financial targets determine how rates are set. Targets include a self-imposed 75/25 debt-to-equity ratio. <u>Manitoba Hydro's financial forecasts are premised on rates being increased sufficiently to allow the debt-to-equity ratio to recover to the target level over a 20-year time period</u>, followed by lesser rate increases thereafter. During the NFAT Review, Manitoba Hydro also provided alternate suggested rate methodologies that would increase rates more gradually, with the result of pushing back the date at which financial targets will fully recover.

A doubling of rates will have a significant effect on all ratepayers. This includes not just residential customers, but also commercial and industrial ratepayers, the latter of which are sensitive to price increases as it can affect their competitive position. <u>The Panel supports a relaxation of Manitoba Hydro's 75/25 debt-to-equity ratio to smooth out rate increases</u> and the Panel concludes that Manitoba Hydro would still be left with sufficient retained earnings if the equity level was decreased." (emphasis added).

QUESTION:

c) Please provide a calculation of CFO:Capex, by year, for the NFAT Preferred Development Plan that Manitoba Hydro recommended which MIPUG understands is Plan 14 Base Level DSM (MH Exhibit 104-12-4 starting at pdf page 1). Show all values underlying the calculation.

d) If Manitoba Hydro does not agree that part (c) represents the best REF-REF-REF baseline scenario for what Hydro recommended at the final Preferred Development Plan in NFAT, please provide a reference for the scenario that MH sees as the best representation of the Preferred Development Plan, and also provide the CFO:Capex for that scenario. Show all values underlying the calculation.
e) Please provide a calculation of CFO:Capex, by year, for the NFAT baseline scenario for what the PUB recommended in their NFAT Report (which MIPUG understands is best represented by Plan 5 DSM 2 - MH Exhibit 104-12-4 starting at pdf page 37). Show all values underlying the calculation.
f) If Manitoba Hydro does not agree that part (e) represents the best REF-REF-REF baseline scenario for what the Board recommended in NFAT, please provide a reference for the scenario that MH sees as the best baseline and also provide the CFO:Capex for that scenario. Show all values underlying the calculation.

RATIONALE FOR QUESTION:

RESPONSE:

c) Consistent with the CFO to Capex calculation as provided in PUB MFR 51 Updated, the CFO to Capex ratio for the NFAT Plan 14 Base Level DSM (MH Exhibit 104-12-4 starting at pdf page 1) can be found below.

   It should be noted that the cash flows projected in these development plan scenarios are a reflection of the projected annual rate increases incorporated in the projected financial statements. For each of the development plans submitted in Manitoba Hydro's 2013 NFAT Application, the projected annual rate increases were determined mechanistically for the purposes of making fair and objective comparisons between the plans (NFAT Transcript page 2767).

   It was noted at NFAT Transcript page 2768 that the mechanistic approach to rate setting could result in rate increases that were volatile and that "actual rate increases would vary from those [projected at NFAT], and will depend on many other factors…not just the choice of development plan [but also] due to changing water flows, weather and costs to maintain the system, and economic variables (NFAT Transcript page 2769).

Manitoba Hydro further noted at NFAT Transcript page 2776 that the annual rate increases projected for comparative purposes could be higher than even 3.95% in order to mitigate several years of financial losses. As a result, caution should be used in reliance on the cash flows provided below.

CASH FLOW FROM OPERATIONS TO CAPITAL EXPENDITURES
PDP (14) - BASE DSM MAIN SUBMISSION RATE METHODOLOGY
(Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cash Receipts from Customers	1 692	1 819	1 861	1 919	2 039	2 170	2 274	2 413	2 796	3 013	3 153	3 283
Cash Paid to Suppliers and Employees	(782)	(810)	(857)	(904)	(940)	(983)	(1 013)	(1 042)	(1 126)	(1 163)	(1 191)	(1 220)
Interest Paid	(467)	(483)	(512)	(543)	(599)	(695)	(814)	(814)	(1 082)	(1 182)	(1 160)	(1 161)
Add Back Total CEF Capitalized Interest	(104)	(108)	(159)	(249)	(319)	(341)	(333)	(415)	(261)	(234)	(310)	(385)
Gross Interest	(571)	(592)	(671)	(792)	(918)	(1 036)	(1 146)	(1 229)	(1 343)	(1 416)	(1 470)	(1 546)
Deduct Capitalized Interest on Major Projects*	84	64	69	104	157	227	321	403	248	220	293	361
Interest Received	28	17	24	25	30	37	40	38	35	32	18	20
CASH FLOW FROM OPERATIONS (Restated)	**451**	**499**	**427**	**353**	**367**	**414**	**476**	**583**	**609**	**686**	**802**	**898**
Electric PP&E from Cash Flow Statement	1 311	1 955	2 280	2 197	2 154	2 139	2 075	2 143	1 726	1 927	1 804	1 804
Less: Capitalized Interest Included in PP&E Above	(104)	(108)	(159)	(249)	(319)	(341)	(333)	(415)	(261)	(234)	(310)	(385)
CEF Cash Flows including Deferreds	1 207	1 847	2 120	1 948	1 835	1 798	1 743	1 728	1 465	1 693	1 494	1 419
Deduct Major Projects Capex**	(417)	(912)	(1 342)	(1 346)	(1 327)	(1 348)	(1 254)	(1 301)	(981)	(1 125)	(866)	(778)
CAPITAL EXPENDITURES	**791**	**934**	**778**	**602**	**507**	**449**	**489**	**426**	**484**	**568**	**627**	**641**
CFO to CAPEX RATIO	**0.57**	**0.53**	**0.55**	**0.59**	**0.72**	**0.92**	**0.97**	**1.37**	**1.26**	**1.21**	**1.28**	**1.40**
Surplus Available to Retire Debt / (Deficiency)	**(340)**	**(436)**	**(351)**	**(249)**	**(141)**	**(35)**	**(13)**	**156**	**125**	**118**	**175**	**256**

*** Includes Incremental Development Plan Capital excluding BPIII**
**** Includes Incremental Development Plan Capital including BPIII**

CASH FLOW FROM OPERATIONS TO CAPITAL EXPENDITURES
PDP (14) - BASE DSM MAIN SUBMISSION RATE METHODOLOGY
(Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cash Receipts from Customers	3 405	3 476	3 808	4 227	4 504	4 681	4 870	5 085	4 234	4 264	4 316	4 339
Cash Paid to Suppliers and Employees	(1 255)	(1 274)	(1 305)	(1 321)	(1 362)	(1 384)	(1 400)	(1 427)	(1 452)	(1 477)	(1 501)	(1 514)
Interest Paid	(1 162)	(1 141)	(1 268)	(1 551)	(1 761)	(1 737)	(1 758)	(1 666)	(1 635)	(1 617)	(1 601)	(1 593)
Add Back Total CEF Capitalized Interest	(458)	(545)	(501)	(259)	(65)	(80)	(35)	(27)	(38)	(36)	(11)	(15)
Gross Interest	(1 621)	(1 686)	(1 769)	(1 810)	(1 826)	(1 817)	(1 793)	(1 693)	(1 674)	(1 653)	(1 612)	(1 607)
Deduct Capitalized Interest on Major Projects*	430	518	467	223	5	-	-	-	-	-	-	-
Interest Received	29	34	44	61	79	88	101	81	100	74	67	67
CASH FLOW FROM OPERATIONS (Restated)	**989**	**1 068**	**1 245**	**1 379**	**1 401**	**1 568**	**1 777**	**2 046**	**1 209**	**1 207**	**1 269**	**1 285**
Electric PP&E from Cash Flow Statement	1 762	2 402	1 769	1 264	1 100	1 018	959	822	798	829	830	869
Less: Capitalized Interest Included in PP&E Above	(458)	(545)	(501)	(259)	(65)	(80)	(35)	(27)	(38)	(36)	(11)	(15)
CEF Cash Flows including Deferreds	1 304	1 857	1 268	1 005	1 035	937	924	795	759	793	819	854
Deduct Major Projects Capex**	(659)	(1 181)	(613)	(200)	1	-	-	-	-	-	-	-
CAPITAL EXPENDITURES	**644**	**676**	**656**	**805**	**1 035**	**937**	**924**	**795**	**759**	**793**	**819**	**854**
CFO to CAPEX RATIO	**1.53**	**1.58**	**1.90**	**1.71**	**1.35**	**1.67**	**1.92**	**2.57**	**1.59**	**1.52**	**1.55**	**1.50**
Surplus Available to Retire Debt / (Deficiency)	**345**	**392**	**589**	**574**	**366**	**631**	**853**	**1 251**	**450**	**415**	**450**	**431**

*** Includes Incremental Development Plan Capital excluding BPIII**
**** Includes Incremental Development Plan Capital including BPIII**

d) Plan 14 Base Level DSM (MH Exhibit 104-12-4 starting at pdf page 1) represents the best REF-REF-REF baseline scenario for what Hydro submitted as the Preferred Development Plan in NFAT. It should be noted, however, over the NFAT process timeline, the capital costs of Keeyask and Conawapa increased and the forecasts for load and export prices deteriorated significantly, consequently impacting the economics of Conawapa. As a result, Manitoba Hydro's view of the Preferred Development Plan evolved over the NFAT process to protect Conawapa as an option with a future final decision date and supported the Plan 5 provided in part e) below. Manitoba Hydro, however, did not formally modify its application with respect to Conawapa.

e) Consistent with the CFO to Capex calculation as provided in PUB MFR 51 Updated, the CFO to Capex ratio for the NFAT Plan 5 DSM 2 - MH Exhibit 104-12-4 starting at pdf page 37) can be found below.

Please also see the note in part c) above with respect to the rate increase assumptions underlying the cash flows below and reliance on them.

CASH FLOW FROM OPERATIONS TO CAPITAL EXPENDITURES
KEEYASK - GAS (5) - DSM LEVEL 2 MAIN SUBMISSION RATE METHODOLOGY
(Millions of Dollars)

For the year ended March 31	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cash Receipts from Customers	1 692	1 819	1 854	1 906	2 017	2 142	2 240	2 368	2 735	2 938	3 060	3 172
Cash Paid to Suppliers and Employees	(782)	(810)	(857)	(904)	(939)	(980)	(1 005)	(1 027)	(1 104)	(1 133)	(1 154)	(1 174)
Interest Paid	(467)	(483)	(527)	(570)	(633)	(733)	(866)	(878)	(1 154)	(1 265)	(1 235)	(1 235)
Add Back Total CEF Capitalized Interest	(104)	(108)	(145)	(225)	(290)	(305)	(275)	(312)	(103)	(14)	(18)	(24)
Gross Interest	(571)	(592)	(672)	(795)	(923)	(1 037)	(1 141)	(1 189)	(1 257)	(1 278)	(1 253)	(1 258)
Deduct Capitalized Interest on Major Projects*	84	64	56	81	128	190	264	299	89	-	-	-
Interest Received	28	17	24	25	30	37	40	38	35	32	18	18
CASH FLOW FROM OPERATIONS (Restated)	**451**	**498**	**405**	**313**	**312**	**352**	**397**	**489**	**498**	**558**	**671**	**758**
Electric PP&E from Cash Flow Statement	1 311	1 964	2 279	2 189	2 132	2 050	1 547	1 190	1 019	673	672	692
Less: Capitalized Interest Included in PP&E Above	(104)	(108)	(145)	(225)	(290)	(305)	(275)	(312)	(103)	(14)	(18)	(24)
CEF Cash Flows including Deferreds	1 207	1 855	2 134	1 964	1 842	1 746	1 272	878	916	659	654	668
Deduct Major Projects Capex**	(417)	(912)	(1 314)	(1 313)	(1 239)	(1 239)	(721)	(405)	(397)	(65)	(0)	-
CAPITAL EXPENDITURES	**791**	**943**	**820**	**651**	**603**	**507**	**551**	**474**	**520**	**594**	**654**	**668**
CFO to CAPEX RATIO	**0.57**	**0.53**	**0.49**	**0.48**	**0.52**	**0.69**	**0.72**	**1.03**	**0.96**	**0.94**	**1.03**	**1.13**
Surplus Available to Retire Debt / (Deficiency)	**(340)**	**(445)**	**(415)**	**(338)**	**(291)**	**(155)**	**(153)**	**15**	**(22)**	**(36)**	**17**	**90**

*** Includes Incremental Development Plan Capital excluding BPIII**
**** Includes Incremental Development Plan Capital including BPIII**

CASH FLOW FROM OPERATIONS TO CAPITAL EXPENDITURES
KEEYASK - GAS (5) - DSM LEVEL 2 MAIN SUBMISSION RATE METHODOLOGY
(Millions of Dollars)

For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cash Receipts from Customers	3 276	3 320	3 494	3 599	3 732	3 872	4 045	4 196	3 439	3 473	3 574	3 606
Cash Paid to Suppliers and Employees	(1 202)	(1 208)	(1 236)	(1 251)	(1 278)	(1 299)	(1 307)	(1 354)	(1 382)	(1 415)	(1 446)	(1 452)
Interest Paid	(1 242)	(1 244)	(1 224)	(1 231)	(1 209)	(1 174)	(1 198)	(1 125)	(1 111)	(1 111)	(1 146)	(1 163)
Add Back Total CEF Capitalized Interest	(28)	(27)	(34)	(37)	(60)	(83)	(46)	(29)	(38)	(36)	(11)	(15)
Gross Interest	(1 270)	(1 271)	(1 258)	(1 268)	(1 269)	(1 257)	(1 243)	(1 155)	(1 149)	(1 148)	(1 157)	(1 177)
Deduct Capitalized Interest on Major Projects*	-	-	-	-	0	3	10	2	-	-	-	-
Interest Received	27	30	40	53	66	69	77	51	64	67	70	68
CASH FLOW FROM OPERATIONS (Restated)	**831**	**871**	**1 040**	**1 133**	**1 250**	**1 388**	**1 581**	**1 740**	**973**	**977**	**1 040**	**1 044**
Electric PP&E from Cash Flow Statement	702	732	719	872	1 104	1 128	1 129	853	805	837	838	877
Less: Capitalized Interest Included in PP&E Above	(28)	(27)	(34)	(37)	(60)	(83)	(46)	(29)	(38)	(36)	(11)	(15)
CEF Cash Flows including Deferreds	673	705	685	836	1 044	1 044	1 083	824	767	800	827	863
Deduct Major Projects Capex**	-	-	-	-	(0)	(100)	(152)	(22)	-	-	-	-
CAPITAL EXPENDITURES	**673**	**705**	**685**	**836**	**1 044**	**944**	**931**	**802**	**767**	**800**	**827**	**863**
CFO to CAPEX RATIO	**1.23**	**1.24**	**1.52**	**1.36**	**1.20**	**1.47**	**1.70**	**2.17**	**1.27**	**1.22**	**1.26**	**1.21**
Surplus Available to Retire Debt / (Deficiency)	**157**	**166**	**354**	**297**	**207**	**444**	**650**	**938**	**206**	**177**	**213**	**181**

*** Includes Incremental Development Plan Capital excluding BPIII**
**** Includes Incremental Development Plan Capital including BPIII**

f) The PUB did not specifically recommend one of Manitoba Hydro's development plans in its Need For And Alternatives To (NFAT) Review Final Report. However, based on a comparison of the PUB's recommendations with Manitoba Hydro's Plan 5 DSM 2 - MH Exhibit 104-12-4 (starting at pdf page 37), Plan 5 closely resembles the PUB's recommendations.