**Board Counsel's Book of Documents –
Manitoba Hydro 2019/20 GRA**

Tab #	Description	References
1.	Exhibit MH-93 IFF	MH-93 of 2017/18 MH GRA; Coalition/MH 1-4 c-d
2.	MH15 Proposed Operating Statement ; MH16 Updated with Interim IFF	Appendix 3.8 (Revised) of 2017/18 MH GRA
3.	Reasons for Requested Rate Increase	November 12 & 30 MH Letters: November 21 PUB Letter; November 30 and February 14 Applications; Coalition/MH 1-4 a-b
4.	Net Income Forecasts	Figure 1.1 (Application); Figure 1 (Supplement); Coalition/MH 1-6a-m;
5.	Projected Operating Statements	Figure 2.9 (Application); Figure 7 (Supplement); Figure 3 (Supplement); Approved Budget v. MH93 (20 yr WATM)
6.	Hydrology Updates	PUB/MH I-29a (Updated); Appendix 9 Updated Energy in Storage;
7.	2019/20 Net Income Probabilities	PUB/MH I-29c (Original); PUB/MH I-29c (Updated)
8.	Net Income Key Variable Sensitivity Impacts	Figure 2.10 (Application); Coalition/MH I-8b;
9.	Major Capital Projects and Revenue Requirements	PUB/MH I-9 (Updated); Coalition/MH I-1b; PUB MFR 82R from 2017/18 GRA
10.	Manitoba Minnesota Transmission Project - update	MMTP Q3 report PUB/MH I-54 (Updated)

Tab #	Description	References
11.	Revenue to Cost Coverages and Rate Differentiation	PUB/MH I-61 a & b : PUB/MH 1 -63
12.	Cash Flow	Appendix 1 – Updated Indirect Cash Flow Statements; PUB/MH 1 -4 Updated;
13.	Debt Management Strategy	MIPUG/MH 1-5; PUB/MH 1-40 Updated;
14.	Operating and Administrative Costs	November 30 Application; PUB/MH 1-13 Revised; PUB/MH 1-21; Coalition/MH 1-13;
15.	Regulatory Deferral Accounts	PUB/MH 1 -10c Updated; Coalition/MH 1-16;
16.		
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Manitoba Hydro

2017/18 & 2018/19 ELECTRIC GENERAL RATE APPLICATION

Follow-Up Questions to Manitoba Hydro Undertaking Nos. 7 & 8 from Counsel for MIPUG (email dated December 21, 2017)

On December 21, 2017, MIPUG requested the following:

1. Please provide the data values, by year, used to generate Undertaking 8.

2. Add a line (scenario) to Undertaking 8 (the 1990 base scenario) that is based on an IFF as follows (please provide the underlying IFF 6 page financial forecast scenario as well):
   a) IFF16 Update with Interim assumptions, except where noted.
   b) 12 year WATM
   c) Overhead accruals at $20M continue throughout, amortized at 30 year rate (consistent with PUB/MH-I-1(e))
   d) Depreciation at ASL throughout, no amortization of difference with ELG.
   e) Rate increases as necessary consistent with the approach in Coalition-MH-II-19 (i.e., equal annual increases to target 75:25 by 2035/36)
   f) Make sure the graph goes out to 2035/36.
   g) Please also provide the summary data for this scenario as per Undertaking #9 page 2 (i.e., max net debt, etc.)

Response:

Notwithstanding the concerns outlined below, Manitoba Hydro is providing the data values included in Undertaking No. 8 and the projected financial statements, including data values, reflecting the December 21, 2017 MIPUG Scenario.

As noted in the responses to PUB/MH II-21 and PUB/MH II-28, Manitoba Hydro's financial plan reflects a goal to return to its target 25% equity to capitalization ratio in 10 years and believes limited value should be ascribed to forecasts a decade or more in the future. The potential for volatility in key assumptions, many of which are beyond Manitoba Hydro's ability to control, reduces the second half of a 20 year forecast to little more than a hypothetical modeling exercise.

Manitoba Hydro maintains all the same concerns outlined in PUB/MHI-1d) and e) related to items c) and d) of MIPUG's request. Furthermore, the 12 Year WATM in Manitoba Hydro's debt management strategy is justifiable only if there is a reasonable expectation of sufficient cash flow to retire the repositioned debt. The sufficient cash flow stems from the path of higher rate increases in MH16 Update with Interim and not from the rate path included in the scenario requested by MIPUG and presented below.

Manitoba Hydro

The table below outlines the accounting treatment in MH16 Update with Interim, and the assumptions in part c) and d), of the MIPUG scenario.

	MH16 Update with Interim	MIPUG Scenario Dec 21/17
Ineligible Overhead		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferral Until	2022/23	Indefinite
Equal Life Group (ELG)/Average Service Life (ASL)		
ELG/ASL Amortization Period	20 years	None
ELG/ASL Deferred Until	2022/23	Indefinite

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MIPUG Scenario December 21, 2017
(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	110	168	228	292	357	425	498	577	660
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	2 178	2 251	2 443	2 642	2 791	2 816	2 891	2 845	2 949
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	831	907	1 159	1 205	1 213	1 211	1 226
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(37)	(13)	(12)	(13)	(14)
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	166	174	175	176	177	177
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	2 660	2 406	2 533	2 869	2 965	3 006	3 022	3 069
Net Income before Net Movement in Reg. Deferral	(46)	13	27	(409)	38	109	(78)	(149)	(115)	(177)	(120)
Net Movement in Regulatory Deferral	66	72	115	473	82	78	59	50	50	51	55
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	142	64	120	187	(19)	(99)	(66)	(126)	(65)
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	94	143	61	115	178	(29)	(111)	(69)	(128)	(68)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**94**	**143**	**61**	**115**	**178**	**(29)**	**(111)**	**(69)**	**(128)**	**(68)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	142	64	120	187	(19)	(99)	(66)	(126)	(65)
* Additional Domestic Revenue											
Percent Increase		3.36%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
Cumulative Percent Increase		3.36%	7.05%	10.87%	14.82%	18.92%	23.16%	27.56%	32.11%	36.82%	41.70%
Financial Ratios											
Equity	16%	15%	14%	14%	13%	14%	13%	13%	12%	12%	12%
EBITDA Interest Coverage	1.51	1.54	1.64	1.58	1.62	1.69	1.58	1.52	1.57	1.53	1.58
Capital Coverage	1.53	1.40	1.35	1.18	1.41	1.64	1.33	1.27	1.24	1.12	1.20

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MIPUG Scenario December 21, 2017
(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*	747	839	936	1 038	1 152	1 273	1 401	1 538	1 682
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 045	3 167	3 301	3 433	3 569	3 714	3 866	4 029	4 111
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 239	1 242	1 234	1 255	1 242	1 240	1 228	1 195	1 161
Finance Income	(16)	(21)	(19)	(15)	(16)	(17)	(22)	(23)	(25)
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	179	180	181	183	184	186	188	189	196
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 111	3 142	3 170	3 231	3 232	3 265	3 286	3 296	3 288
Net Income before Net Movement in Reg. Deferral	(66)	25	131	202	337	449	580	733	823
Net Movement in Regulatory Deferral	57	61	67	69	72	75	76	76	75
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	(9)	86	197	271	409	525	655	809	899
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	(13)	81	190	261	398	512	641	793	883
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**(13)**	**81**	**190**	**261**	**398**	**512**	**641**	**793**	**883**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	(9)	86	197	271	409	525	655	809	899
* Additional Domestic Revenue									
Percent Increase	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
Cumulative Percent Increase	46.76%	52.00%	57.42%	63.04%	68.85%	74.88%	81.12%	87.58%	94.27%
Financial Ratios									
Equity	12%	12%	13%	14%	15%	17%	19%	22%	25%
EBITDA Interest Coverage	1.63	1.72	1.82	1.87	2.01	2.11	2.25	2.42	2.56
Capital Coverage	1.29	1.39	1.57	1.61	1.81	1.95	2.12	2.12	2.21

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MIPUG Scenario December 21, 2017
(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	2 199	2 477	2 505	1 928	1 682	1 681	1 628	1 770	1 744
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	27 057	28 431	29 997	30 109	30 103	30 051	29 940	30 035	29 969
Regulatory Deferral Balance	462	534	649	1 121	1 204	1 281	1 340	1 390	1 440	1 491	1 546
	21 733	24 839	27 706	29 552	31 200	31 390	31 443	31 442	31 380	31 526	31 515
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 650	24 862	24 735	24 447	24 186	25 228
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 359	4 147	3 027	3 184	3 468	3 993	2 998
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	2 986	3 047	3 162	3 340	3 311	3 200	3 132	3 003	2 935
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(437)	(339)	(338)	(337)	(337)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 657	29 504	31 152	31 341	31 395	31 393	31 331	31 477	31 466
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 706	29 552	31 200	31 390	31 443	31 442	31 380	31 526	31 515
Net Debt	15 427	18 473	20 813	22 628	23 759	24 424	24 666	24 702	24 765	24 891	24 963
Total Equity	2 856	3 163	3 443	3 558	3 698	3 881	3 549	3 532	3 478	3 363	3 309
Equity Ratio	16%	15%	14%	14%	13%	14%	13%	13%	12%	12%	12%

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MIPUG Scenario December 21, 2017
(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	2 012	2 450	2 194	2 054	2 443	2 521	3 066	3 434	4 183
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 192	30 601	30 294	30 127	30 480	30 519	31 020	31 407	32 175
Regulatory Deferral Balance	1 603	1 664	1 731	1 800	1 871	1 947	2 022	2 098	2 174
	31 795	32 265	32 025	31 927	32 351	32 465	33 043	33 505	34 349
LIABILITIES AND EQUITY									
Long-Term Debt	25 560	23 583	21 090	22 750	22 713	23 363	23 080	23 459	23 543
Current and Other Liabilities	2 949	5 307	7 361	5 332	5 386	4 329	4 539	3 819	3 685
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	2 922	3 002	3 192	3 453	3 851	4 363	5 004	5 798	6 680
Accumulated Other Comprehensive Income	(337)	(337)	(337)	(337)	(337)	(337)	(337)	(337)	(337)
Total Liabilities and Equity before Regulatory Deferral	31 747	32 216	31 976	31 878	32 302	32 417	32 994	33 456	34 300
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 795	32 265	32 025	31 927	32 351	32 465	33 043	33 505	34 349
Net Debt	24 971	24 899	24 713	24 476	24 091	23 592	22 950	22 221	21 403
Total Equity	3 310	3 396	3 594	3 863	4 269	4 789	5 439	6 242	7 134
Equity Ratio	12%	12%	13%	14%	15%	17%	19%	22%	25%

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

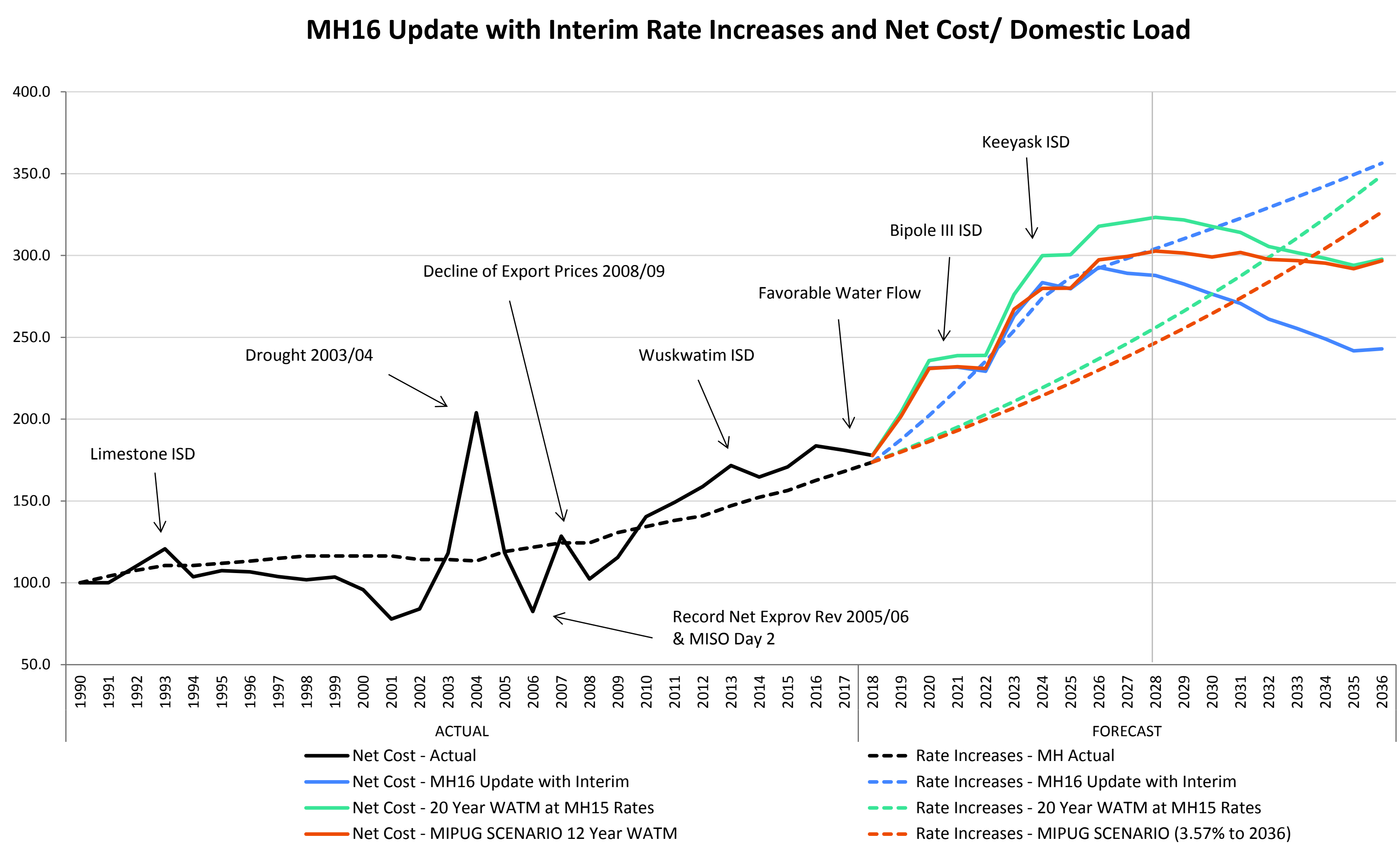
For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 164	2 160	2 352	2 550	2 699	2 777	2 878	2 833	2 936
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(916)	(934)	(934)	(948)
Interest Paid	(553)	(531)	(635)	(704)	(774)	(857)	(1 106)	(1 176)	(1 187)	(1 188)	(1 202)
Interest Received	17	5	11	22	26	19	6	4	6	5	7
	810	734	697	608	718	817	695	690	763	715	792
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 390	1 560	390	390	950	1 190
Sinking Fund Withdrawals	146	0	0	120	318	813	182	54	350	155	253
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(248)	(261)	(270)	(266)	(273)
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	473	364	(111)	53	119	(13)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 659)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(720)	(724)	(752)	(776)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 748)	(3 059)	(2 437)	(1 850)	(1 477)	(997)	(816)	(820)	(834)	(858)
Net Increase (Decrease) in Cash	(309)	(146)	4	31	(23)	(187)	62	(237)	(3)	(0)	(78)
Cash at Beginning of Year	943	634	488	492	523	500	313	375	138	135	134
Cash at End of Year	634	488	492	523	500	313	375	138	135	134	56

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MIPUG Scenario December 21, 2017
(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	3 032	3 154	3 287	3 419	3 555	3 700	3 851	4 014	4 097
Cash Paid to Suppliers and Employees	(963)	(979)	(996)	(1 019)	(1 015)	(1 028)	(1 049)	(1 073)	(1 083)
Interest Paid	(1 216)	(1 232)	(1 239)	(1 246)	(1 226)	(1 237)	(1 224)	(1 210)	(1 175)
Interest Received	14	28	27	15	12	23	30	41	41
	867	972	1 079	1 169	1 326	1 458	1 609	1 773	1 880
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	390	390	1 970	3 990	2 350	1 940	1 160	1 100	570
Sinking Fund Withdrawals	150	60	510	540	0	230	51	10	463
Sinking Fund Payment	(274)	(282)	(291)	(278)	(266)	(276)	(274)	(282)	(289)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 284)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	111	103	(256)	(149)	(294)	(503)	(351)	(663)	74
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(787)	(818)	(813)	(852)	(860)	(877)	(890)	(968)	(986)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(867)	(893)	(884)	(925)	(933)	(948)	(960)	(1 036)	(1 053)
Net Increase (Decrease) in Cash	111	182	(62)	96	99	7	298	75	901
Cash at Beginning of Year	56	167	348	287	383	482	489	787	862
Cash at End of Year	167	348	287	383	482	489	787	862	1 763

Manitoba Hydro



Manitoba Hydro

MH16 Update with Interim														
	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
				Millions of Dollars										
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	**1990**		**100**	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34		**100**
	1991	4.00%	**104**	650	50	67	4	-	-	529	15 447	34	0.1%	**100**
	1992	3.50%	**108**	735	54	97	3	-	-	582	15 397	38	10.2%	**110**
	1993	2.70%	**111**	843	53	143	3	-	-	644	15 577	41	9.5%	**121**
	1994	0.00%	**111**	851	53	232	3	-	-	564	15 870	36	-14.1%	**104**
	1995	1.20%	**112**	885	54	253	4	-	-	574	15 600	37	3.6%	**107**
	1996	1.20%	**113**	915	56	245	4	-	-	609	16 654	37	-0.7%	**107**
	1997	1.50%	**115**	922	50	268	5	-	-	599	16 851	36	-2.8%	**104**
	1998	1.30%	**116**	931	46	297	5	-	-	582	16 681	35	-1.8%	**102**
	1999	0.00%	**116**	982	48	326	7	-	-	600	16 929	35	1.6%	**104**
	2000	0.00%	**116**	976	42	376	11	-	-	547	16 696	33	-7.51%	**96**
	2001	0.00%	**116**	1 002	46	480	7	-	-	469	17 590	27	-18.7%	**78**
	2002	-1.92%	**114**	1 158	47	588	11	-	-	512	17 805	29	7.9%	**84**
	2003	0.00%	**114**	1 277	20	463	15	-	-	779	19 246	40	40.7%	**118**
	2004	-0.72%	**113**	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	**204**
	2005	5.00%	**119**	1 370	-	554	15	-	-	801	19 735	41	-41.9%	**119**
	2006	2.25%	**122**	1 408	-	827	18	-	-	563	19 935	28	-30.4%	**83**
	2007	2.25%	**124**	1 511	-	592	16	-	-	902	20 510	44	55.7%	**128**
	2008	0.00%	**124**	1 370	-	625	8	-	-	738	21 061	35	-20.4%	**102**
	2009	5.00%	**131**	1 478	-	623	16	-	-	839	21 210	40	12.9%	**116**
	2010	2.84%	**134**	1 418	-	427	6	-	-	985	20 486	48	21.6%	**140**
	2011	2.80%	**138**	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	**149**
	2012	2.00%	**141**	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	**159**
	2013	4.40%	**147**	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	**172**
	2014	3.50%	**152**	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	**165**
	2015	2.75%	**156**	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	**171**
	2016	3.95%	**163**	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	**184**
	2017	3.36%	**168**	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	**181**
Forecast	**2018**	3.36%	**174**	1 995	-	514	30	8	72	1 371	22 510	61	-1.8%	**178**
	2019	7.90%	**187**	2 150	-	469	31	1	114	1 535	22 224	69	13.4%	**202**
	2020	7.90%	**202**	2 655	-	420	31	(2)	464	1 741	21 977	79	14.7%	**231**
	2021	7.90%	**218**	2 392	-	567	33	(5)	71	1 726	21 750	79	0.2%	**232**
	2022	7.90%	**235**	2 507	-	693	33	(9)	64	1 725	21 971	79	-1.1%	**229**
	2023	7.90%	**254**	2 822	-	779	34	(10)	43	1 977	21 940	90	14.8%	**263**
	2024	7.90%	**274**	2 893	-	788	34	(11)	(48)	2 130	21 947	97	7.7%	**283**
	2025	4.54%	**287**	2 904	-	805	35	(3)	(50)	2 117	22 103	96	-1.3%	**280**
	2026	2.00%	**292**	2 887	-	667	35	(2)	(49)	2 236	22 303	100	4.6%	**293**
	2027	2.00%	**298**	2 889	-	671	36	(3)	(45)	2 231	22 531	99	-1.2%	**289**
	2028	2.00%	**304**	2 894	-	662	36	(4)	(44)	2 243	22 758	99	-0.5%	**288**
	2029	2.00%	**310**	2 892	-	677	37	(5)	(40)	2 223	22 976	97	-1.8%	**283**
	2030	2.00%	**316**	2 888	-	697	38	(8)	(35)	2 196	23 204	95	-2.2%	**276**
	2031	2.00%	**323**	2 878	-	709	38	(10)	(33)	2 173	23 443	93	-2.1%	**271**
	2032	2.00%	**329**	2 833	-	705	39	(11)	(31)	2 130	23 819	89	-3.5%	**261**
	2033	2.00%	**336**	2 818	-	701	40	(13)	(28)	2 118	24 216	87	-2.2%	**255**
	2034	2.00%	**342**	2 792	-	696	40	(14)	(28)	2 099	24 614	85	-2.5%	**249**
	2035	2.00%	**349**	2 762	-	694	40	(15)	(28)	2 071	25 024	83	-2.9%	**242**
	2036	2.00%	**356**	2 714	-	602	41	(16)	(30)	2 117	25 442	83	0.5%	**243**

* CGAAP 2000-2014, IFRS 2015-2027
** Includes Water Rentals & Assessments and Fuel and Power Purchased
***2017 includes $20 million non-recurring gain

Manitoba Hydro

MH16 Update with Interim with 20 Year WATM and MH15 Rates														
	Fiscal Year*	**Rate Increase**	**Rate Increase Index**	**Total Expenses****	**Winnipeg Hydro Revenue**	**Extra-Provincial**	**Other Revenue*****	**Non-Controlling Interest**	**Net Movement**	**Net Cost**	**Domestic Load (GWh)**	**Net Cost/MWh**	**Net Cost/MWh Yr over Yr Increase**	**Net Cost Index**
				Millions of Dollars										
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	**1990**		**100**	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34		**100**
	1991	4.00%	**104**	650	50	67	4	-	-	529	15 447	34	0.1%	**100**
	1992	3.50%	**108**	735	54	97	3	-	-	582	15 397	38	10.2%	**110**
	1993	2.70%	**111**	843	53	143	3	-	-	644	15 577	41	9.5%	**121**
	1994	0.00%	**111**	851	53	232	3	-	-	564	15 870	36	-14.1%	**104**
	1995	1.20%	**112**	885	54	253	4	-	-	574	15 600	37	3.6%	**107**
	1996	1.20%	**113**	915	56	245	4	-	-	609	16 654	37	-0.7%	**107**
	1997	1.50%	**115**	922	50	268	5	-	-	599	16 851	36	-2.8%	**104**
	1998	1.30%	**116**	931	46	297	5	-	-	582	16 681	35	-1.8%	**102**
	1999	0.00%	**116**	982	48	326	7	-	-	600	16 929	35	1.6%	**104**
	2000	0.00%	**116**	976	42	376	11	-	-	547	16 696	33	-7.51%	**96**
	2001	0.00%	**116**	1 002	46	480	7	-	-	469	17 590	27	-18.7%	**78**
	2002	-1.92%	**114**	1 158	47	588	11	-	-	512	17 805	29	7.9%	**84**
	2003	0.00%	**114**	1 277	20	463	15	-	-	779	19 246	40	40.7%	**118**
	2004	-0.72%	**113**	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	**204**
	2005	5.00%	**119**	1 370	-	554	15	-	-	801	19 735	41	-41.9%	**119**
	2006	2.25%	**122**	1 408	-	827	18	-	-	563	19 935	28	-30.4%	**83**
	2007	2.25%	**124**	1 511	-	592	16	-	-	902	20 510	44	55.7%	**128**
	2008	0.00%	**124**	1 370	-	625	8	-	-	738	21 061	35	-20.4%	**102**
	2009	5.00%	**131**	1 478	-	623	16	-	-	839	21 210	40	12.9%	**116**
	2010	2.84%	**134**	1 418	-	427	6	-	-	985	20 486	48	21.6%	**140**
	2011	2.80%	**138**	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	**149**
	2012	2.00%	**141**	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	**159**
	2013	4.40%	**147**	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	**172**
	2014	3.50%	**152**	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	**165**
	2015	2.75%	**156**	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	**171**
	2016	3.95%	**163**	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	**184**
	2017	3.36%	**168**	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	**181**
Forecast	**2018**	3.36%	**174**	1 998	-	514	30	8	72	1 374	22 510	61	-1.8%	**178**
	2019	3.95%	**181**	2 171	-	469	31	1	114	1 556	22 224	70	14.7%	**204**
	2020	3.95%	**188**	2 692	-	420	31	(2)	464	1 778	21 977	81	15.6%	**236**
	2021	3.95%	**195**	2 449	-	567	33	(5)	71	1 783	21 750	82	1.3%	**239**
	2022	3.95%	**203**	2 584	-	693	33	(9)	64	1 802	21 971	82	0.0%	**239**
	2023	3.95%	**211**	2 925	-	779	34	(10)	43	2 080	21 940	95	15.6%	**276**
	2024	3.95%	**219**	3 022	-	788	34	(11)	(48)	2 259	21 947	103	8.6%	**300**
	2025	3.95%	**228**	3 067	-	805	35	(3)	(50)	2 280	22 103	103	0.2%	**301**
	2026	3.95%	**237**	3 085	-	667	35	(2)	(49)	2 433	22 303	109	5.8%	**318**
	2027	3.95%	**246**	3 136	-	671	36	(3)	(45)	2 478	22 531	110	0.8%	**320**
	2028	3.95%	**256**	3 176	-	662	36	(4)	(44)	2 525	22 758	111	0.9%	**323**
	2029	3.95%	**266**	3 206	-	677	37	(6)	(40)	2 537	22 976	110	-0.5%	**322**
	2030	3.95%	**277**	3 223	-	697	38	(8)	(35)	2 531	23 204	109	-1.2%	**318**
	2031	3.95%	**287**	3 232	-	709	38	(10)	(33)	2 527	23 443	108	-1.1%	**314**
	2032	3.95%	**299**	3 199	-	705	39	(11)	(31)	2 497	23 819	105	-2.8%	**305**
	2033	3.95%	**311**	3 207	-	701	40	(13)	(28)	2 507	24 216	104	-1.2%	**302**
	2034	3.95%	**323**	3 213	-	696	40	(14)	(28)	2 519	24 614	102	-1.1%	**298**
	2035	3.95%	**336**	3 214	-	694	40	(16)	(28)	2 524	25 024	101	-1.4%	**294**
	2036	3.95%	**349**	3 197	-	602	41	(16)	(30)	2 600	25 442	102	1.3%	**298**

* CGAAP 2000-2014, IFRS 2015-2027
** Includes Water Rentals & Assessments and Fuel and Power Purchased
***2017 includes $20 million non-recurring gain

Manitoba Hydro

MIPUG DECEMBER 21, 2017 SCENARIO														
	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
				Millions of Dollars										
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	**1990**	0	**100**	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34	0.0%	**100**
	1991	4.00%	**104**	650	50	67	4	-	-	529	15 447	34	0.1%	**100**
	1992	3.50%	**108**	735	54	97	3	-	-	582	15 397	38	10.2%	**110**
	1993	2.70%	**111**	843	53	143	3	-	-	644	15 577	41	9.5%	**121**
	1994	0.00%	**111**	851	53	232	3	-	-	564	15 870	36	-14.1%	**104**
	1995	1.20%	**112**	885	54	253	4	-	-	574	15 600	37	3.6%	**107**
	1996	1.20%	**113**	915	56	245	4	-	-	609	16 654	37	-0.7%	**107**
	1997	1.50%	**115**	922	50	268	5	-	-	599	16 851	36	-2.8%	**104**
	1998	1.30%	**116**	931	46	297	5	-	-	582	16 681	35	-1.8%	**102**
	1999	0.00%	**116**	982	48	326	7	-	-	600	16 929	35	1.6%	**104**
	2000	0.00%	**116**	976	42	376	11	-	-	547	16 696	33	-7.51%	**96**
	2001	0.00%	**116**	1 002	46	480	7	-	-	469	17 590	27	-18.7%	**78**
	2002	-1.92%	**114**	1 158	47	588	11	-	-	512	17 805	29	7.9%	**84**
	2003	0.00%	**114**	1 277	20	463	15	-	-	779	19 246	40	40.7%	**118**
	2004	-0.72%	**113**	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	**204**
	2005	5.00%	**119**	1 370	-	554	15	-	-	801	19 735	41	-41.9%	**119**
	2006	2.25%	**122**	1 408	-	827	18	-	-	563	19 935	28	-30.4%	**83**
	2007	2.25%	**124**	1 511	-	592	16	-	-	902	20 510	44	55.7%	**128**
	2008	0.00%	**124**	1 370	-	625	8	-	-	738	21 061	35	-20.4%	**102**
	2009	5.00%	**131**	1 478	-	623	16	-	-	839	21 210	40	12.9%	**116**
	2010	2.84%	**134**	1 418	-	427	6	-	-	985	20 486	48	21.6%	**140**
	2011	2.80%	**138**	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	**149**
	2012	2.00%	**141**	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	**159**
	2013	4.40%	**147**	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	**172**
	2014	3.50%	**152**	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	**165**
	2015	2.75%	**156**	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	**171**
	2016	3.95%	**163**	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	**184**
	2017	3.36%	**168**	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	**181**
Forecast	**2018**	3.36%	**174**	1 995	-	514	30	8	72	1 370	22 510	61	-1.8%	**178**
	2019	3.57%	**180**	2 150	-	469	31	1	115	1 534	22 224	69	13.4%	**202**
	2020	3.57%	**186**	2 660	-	420	31	(2)	473	1 738	21 977	79	14.5%	**231**
	2021	3.57%	**193**	2 406	-	567	33	(5)	82	1 729	21 750	79	0.5%	**232**
	2022	3.57%	**200**	2 533	-	693	33	(9)	78	1 738	21 971	79	-0.5%	**231**
	2023	3.57%	**207**	2 869	-	779	34	(10)	59	2 007	21 940	91	15.7%	**267**
	2024	3.57%	**214**	2 965	-	788	34	(11)	50	2 104	21 947	96	4.8%	**280**
	2025	3.57%	**222**	3 006	-	805	35	(3)	50	2 120	22 103	96	0.0%	**280**
	2026	3.57%	**230**	3 022	-	667	35	(2)	51	2 271	22 303	102	6.2%	**297**
	2027	3.57%	**238**	3 069	-	671	36	(3)	55	2 311	22 531	103	0.7%	**299**
	2028	3.57%	**247**	3 111	-	662	36	(4)	57	2 359	22 758	104	1.1%	**303**
	2029	3.57%	**255**	3 142	-	677	37	(5)	61	2 373	22 976	103	-0.4%	**302**
	2030	3.57%	**265**	3 170	-	697	38	(8)	67	2 376	23 204	102	-0.8%	**299**
	2031	3.57%	**274**	3 231	-	709	38	(10)	69	2 424	23 443	103	0.9%	**302**
	2032	3.57%	**284**	3 232	-	705	39	(11)	72	2 427	23 819	102	-1.4%	**298**
	2033	3.57%	**294**	3 265	-	701	40	(13)	75	2 462	24 216	102	-0.2%	**297**
	2034	3.57%	**304**	3 286	-	696	40	(14)	76	2 489	24 614	101	-0.5%	**295**
	2035	3.57%	**315**	3 296	-	694	40	(15)	76	2 501	25 024	100	-1.2%	**292**
	2036	3.57%	**327**	3 288	-	602	41	(16)	75	2 585	25 442	102	1.7%	**297**

* CGAAP 2000-2014, IFRS 2015-2027
** Includes Water Rentals & Assessments and Fuel and Power Purchased
***2017 includes $20 million non-recurring gain

To note, in Appendix 1.6 in Manitoba Hydro's Rebuttal Evidence, 3.95% rate increases to 2035/36 results in a 27% equity ratio in that year. Targeting a 25% equity ratio in 2035/36 would yield even annual rate increases of 3.88%. The table below breaks down the impacts of MIPUG's accounting and debt terming assumptions to arrive at 3.57%.

Assumption	**Scenario**	**Even Annual Rate Impact from 2018/19 - 2035/36**	**Even Annual Rate Increase from 2018/19 - 2035/36**
Targeting 25% Equity in 2035/36	MH16 Update with Interim with 20 Year Debt		3.88%
MIPUG's Accounting Changes	MH16 Update with Interim with 20 Year Debt and MIPUG Scenario Ineligible Overhead and ELG/ASL Assumptions	- (0.16%)	3.72%
Debt Terming	MH16 Update with Interim with 12 Year Debt and MIPUG Scenario Ineligible Overhead and ELG/ASL Assumptions	- (0.15%)	3.57%

Manitoba Hydro

As requested, the summary data for the December 21, 2017 MIPUG Scenario has been added to the table shown on page 2 of Undertaking #9. The updated table is provided below.

	Long Term Rate Increase	25% Equity Ratio	Maximum Long-Term Debt	Minimum Equity	Negative Net Income	Retained Earnings at 2033/34	Maximum Net Debt
NFAT Plan 5 - High Keeyask Level 2 DSM	3.95% in 2014/15; 3.99% 2015/16 to 2031/32	2031/32	$22.490 B in 2023/24	8% in 2021/22 - 2023/24	Total of $638 M in 8 years during 2015/16 - 2022/23	$6.659 B	$21.606 B in 2022/23
MH14	3.95% 2015/16 to 2030/31	2033/34	$24.476 B in 2028/29	10% in 2022/23 - 2026/27	Total of $977 M in 8 years during 2018/19 - 2025/26	$5.557 B	$23.227 B in 2024/25
MH15	3.95% 2016/17 to 2028/29	2031/32	$23.495 B in 2026/27	12% in 2021/22 - 2023/24	Total of $58 M in 3 years during 2018/19 - 2022/23	$7.402 B	$22.589 B in 2021/22
Coalition/MH II-19 (Based on MH16 Update with Interim)	3.36% in 2017/18; 4.14% 2018/19 to 2033/34	2033/34	$24.972 B in 2027/28	12% in 2025/26 - 2026/27	Total of $347 M in 4 years during 2023/24 - 2026/27	$6.385 B	$24.506 B in 2022/23
Coalition/MH II-19 20 Year WATM (Based on MH16 Update with Interim)	3.36% in 2017/18; 4.34% 2018/19 to 2033/34	2033/34	$25.315 B in 2028/29	11% in 2025/26 - 2026/27	Total of $507 M in 5 years during 2022/23 - 2026/27	$6.377 B	$24.692 B in 2025/26
MIPUG Scenario December 21, 2017	3.36% in 2017/18; 3.57% 2018/19 to 2035/36	2035/36	$25.560 B in 2027/28	12% in 2024/25 - 2028/29	Total of $418 M in 6 years during 2022/23 - 2026/27	$5.004 B	$24.971 B in 2027/28

REFERENCE:

Current Application p. 1, PUB/MH I-3 (a) (b) (c)

PREAMBLE TO IR (IF ANY):

In its letter to the PUB of August 15, 2018, MH acknowledged that it was in a position to submit a GRA notwithstanding any clear guidance from the PUB on reserve maintenance or any other financial metrics that the PUB will consider in rate-setting (last paragraph page 2). On page 1 of the current application, MH indicates that with the appointment of a new MHEB (in March and June of 2018 per MH's letter to PUB of November 12, 2018), a comprehensive review of MH's operations, forecasts and financial plans is currently being undertaken to allow the MH to establish a long-term financial plan. Upon the MHEB's development and approval of a long-term financial plan, MH will submit a full GRA as well as a fulsome review of responses to PUB directives from Order 59/18, which is anticipated to be filed in late 2019.

QUESTION:

c) Please provide details of the MHEB comprehensive review of MH including (i) scope of review/terms of reference (ii) expected deliverables (including any reports that will be filed with the PUB) (iii) timing of completion of expected deliverables.
d) Please provide current details of the steps/timelines to produce an updated IFF and a comprehensive Electric GRA with response to PUB directives from Order 59/18? Please indicate if MH has yet determined the proposed implementation date for a 2020/21 rate change.

RATIONALE FOR QUESTION:

To further understand the special circumstances surrounding the 2019/20 rate application and the plans outlined by MH in terms of filing a comprehensive GRA late in 2019. Manitoba Hydro's future plans regarding the MHEB review and its 2020/21 GRA is relevant to the issue of the impact of the increase on consumers.

RESPONSE:

c) and d)

Manitoba Hydro is in the process of initiating the development of a 20 year Corporate Strategic Plan ("CSP") which will include consultation with all of our key stakeholders. The scope of review/terms of reference is under development.

A 20 year Corporate Strategic Plan is required to set the direction of Manitoba Hydro going forward and will underpin the development of the Corporation's long term financial plan and rate strategy. As this is a new undertaking, Manitoba Hydro needs to ensure it is comprehensive. This process will be the Corporation's focus over the next fiscal year and will form the basis for Manitoba Hydro's next rate application.

Manitoba Hydro anticipates the process will begin in the Spring of 2019 and the intent is to complete the CSP within the 2019/20 fiscal year. As such Manitoba Hydro has not yet determined a proposed implementation date for a 2020/21 rate change.

2

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
PROJECTED OPERATING STATEMENT
MH16 Update with Interim
(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	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
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	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
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	176
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	2 655	2 392	2 507	2 822	2 893	2 904	2 887	2 889
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	582	540	625
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Net Income	41	85	209	208	354	526	443	423	533	491	580
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	205	349	518	434	411	530	489	577
Non-recurring Gain	20	0	0	0	0	0	0	0	0	0	0
Manitoba Hydro	**53**	**93**	**211**	**205**	**349**	**518**	**434**	**411**	**530**	**489**	**577**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.24	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.34	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH16 Update with Interim
(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*	1 294	1 364	1 438	1 515	1 603	1 696	1 793	1 894	1 999
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 591	3 693	3 803	3 910	4 021	4 138	4 257	4 385	4 428
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	909	850	800	742	675	618
Finance Income	(29)	(46)	(57)	(18)	(19)	(19)	(26)	(32)	(50)
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	177	177	178	179	180	181	183	184	190
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 894	2 892	2 888	2 878	2 833	2 818	2 792	2 762	2 714
Net Income before Net Movement in Reg. Deferral	698	801	915	1 032	1 189	1 320	1 465	1 623	1 714
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Net Income	654	761	880	999	1 158	1 292	1 437	1 595	1 684
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	650	755	873	989	1 147	1 280	1 423	1 579	1 668
Non-recurring Gain	0	0	0	0	0	0	0	0	0
Manitoba Hydro	**650**	**755**	**873**	**989**	**1 147**	**1 280**	**1 423**	**1 579**	**1 668**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
* Additional Domestic Revenue									
Percent Increase	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	80.95%	84.57%	88.26%	92.03%	95.87%	99.79%	103.78%	107.86%	112.01%
Financial Ratios									
Equity	27%	30%	33%	37%	41%	46%	52%	57%	64%
EBITDA Interest Coverage	2.48	2.65	2.85	3.09	3.45	3.79	4.25	4.86	5.52
Capital Coverage	2.39	2.47	2.68	2.71	2.93	3.08	3.25	3.16	3.23

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim
(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	2 269	2 498	2 569	1 943	1 773	1 989	2 230	2 086	2 199
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	27 127	28 452	30 060	30 123	30 194	30 360	30 542	30 350	30 423
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	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
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	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 515	31 194	31 321	31 434	31 552	31 685	31 444	31 473
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 831	22 201	21 613	20 947
Total Equity	2 856	3 163	3 511	3 770	4 143	4 666	4 783	5 262	5 806	6 309	6 900
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH16 Update with Interim
(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	2 824	3 630	2 359	2 041	2 278	2 625	3 629	4 069	5 509
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	31 004	31 781	30 458	30 114	30 315	30 623	31 584	32 041	33 501
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	14 928	15 788	14 751	14 977	14 280	13 859	13 743
Current and Other Liabilities	2 920	5 271	7 325	5 089	5 140	3 906	4 103	3 363	3 230
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	7 214	7 969	8 842	9 831	10 977	12 257	13 680	15 259	16 927
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	32 010	32 747	31 389	31 012	31 183	31 463	32 395	32 824	34 254
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	32 058	32 796	31 438	31 061	31 231	31 511	32 444	32 873	34 303
Net Debt	20 197	19 357	18 386	17 327	16 094	14 725	13 200	11 587	9 877
Total Equity	7 564	8 325	9 206	10 203	11 357	12 645	14 077	15 665	17 343
Equity Ratio	27%	30%	33%	37%	41%	46%	52%	57%	64%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim
(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	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(953)	(966)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 169	1 171	1 287	1 437	1 408	1 512
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
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	1 661	908	73	(28)	(507)	(342)	(877)	(603)
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)	74	(18)	19	(236)	146	(16)	295	(283)	71
Cash at Beginning of Year	943	634	488	562	544	564	328	474	458	754	471
Cash at End of Year	634	488	562	544	564	328	474	458	754	471	541

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH16 Update with Interim
(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	3 578	3 679	3 789	3 896	4 007	4 123	4 243	4 370	4 413
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 087)	(1 097)
Interest Paid	(1 019)	(1 014)	(997)	(908)	(837)	(795)	(742)	(696)	(632)
Interest Received	26	51	63	20	15	22	36	49	67
	1 604	1 720	1 843	1 972	2 155	2 307	2 473	2 637	2 752
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	170	2 990	1 150	1 140	360	(100)	(30)
Sinking Fund Withdrawals	150	60	310	520	0	30	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(218)	(195)	(193)	(188)	(189)	(184)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 208)	(1 109)	(1 223)	(1 219)	(704)	(1 383)	(209)
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	505	594	(1 229)	(41)	19	160	829	238	1 510
Cash at Beginning of Year	541	1 047	1 640	411	370	389	549	1 378	1 616
Cash at End of Year	1 047	1 640	411	370	389	549	1 378	1 616	3 126

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Manitoba Hydro

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November 12, 2018

Mr. D. Christle
Secretary and Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO – PROPOSED 2019/20 GENERAL RATE APPLICATION

Manitoba Hydro is writing to advise of its intentions with respect to the filing of a 2019/20 General Rate Application and to seek comment from the PUB as to the proposal outlined herein.

As you are aware, the Corporation has committed to filing a General Rate Application related to the natural gas operations by November 30, 2018 and the PUB has communicated its intent to conduct a full review, inclusive of an oral hearing. In addition, earlier this year, the PUB completed a lengthy and comprehensive review of Manitoba Hydro's operations, forecasts, financial plans, capital expenditures, and operating expenses which resulted in Order 59/18, dated May 1, 2018, approving a 3.6% average rate increase effective June 1, 2018. Order 59/18 also contained a significant number of directives, requiring work to be undertaken and completed by Manitoba Hydro prior to filing its next GRA.

The PUB is also aware that since the conclusion of the GRA hearing which led to Order 59/18, five new members were appointed to the Manitoba Hydro-Electric Board ("MHEB") in March 2018 and an additional four members were appointed at the end of June, 2018. The MHEB is currently undertaking a comprehensive review of the Manitoba Hydro operations, forecasts and financial plans which will allow them to establish a financial plan for the Corporation.

As a result of the foregoing, Manitoba Hydro intends to seek PUB approval of a one-year rate increase sufficient to generate a minimum level of net income such that the Corporation would avoid a projected net loss in the 2019/20 fiscal year. Manitoba Hydro is not presently in a position to submit a long-term financial forecast (IFF) (i.e. 2020/21 and thereafter) for review by the PUB. However, Manitoba Hydro's current financial projections indicate that, absent rate relief, the Corporation will experience a projected net loss in the 2019/20 fiscal year. Manitoba Hydro therefore proposes a limited review of the electric operations based upon information that is currently available to the Corporation as set out further below. Upon completion of the Integrated Financial Forecast (IFF19) incorporating the direction of the MHEB regarding the Corporation's financial plan, Manitoba Hydro will submit a full GRA to the PUB, presently anticipated to be filed in late 2019.

Manitoba Hydro is working to address the directives from Order 59/18, however in order to accommodate the need for rate relief in 2019/20 and being mindful of the timelines outlined by the PUB for consideration of a rate application for 2019/20, Manitoba Hydro proposes that further review of directives be addressed at the next full General Rate Application ("GRA"), currently anticipated to be filed in late 2019. While the Corporation expects a fulsome review of outstanding directives in the GRA to be filed in late 2019, Manitoba Hydro offers the following brief update on the status of directives from Order 59/18, as varied by Orders 80/18 and 126/18:

Directive 10 directs Manitoba Hydro to provide information about the Other Cash Payments included in the Cash Flow Statement. Manitoba Hydro would intend to provide this information with the proposed expedited process.

Directives 12 and 13 direct Manitoba Hydro to file details of Operating and Administrative Expenses in light of reduced staffing levels, including details of actual O&A expenditures dating back 10 years and forecast information including pension liability related to reduced staffing levels. Manitoba Hydro notes that its quarterly filings to the PUB include the actual results for 2017/18 as well as O&A expenditures compared to the approved budget for the quarters ending June 30th and will shortly file the report to September 30th due November 14, 2018. Historical information is available on the records of previous proceedings and could be consolidated for the proposed filing, however the level of review implied by the direction to provide 10 years of historical data, considered in light of the fact that transitions to a reduced workforce are still ongoing suggest that the subsequent GRA would be a more appropriate forum for consideration of these directives. For the purposes of the proposed expedited process, Manitoba Hydro expects to be able to provide the annual budget for 2018/19 and a high level summary of the impact of the Voluntary Departure Program on pension liability.

Directive 14 directed the retention of an independent consultant to assess Manitoba Hydro's development of its asset management program, and in accordance with Order 90/18, Manitoba Hydro filed Terms of Reference for the retention of a consultant on August 31, 2018 on a without prejudice basis with the agreement that this matter would be held in abeyance pending the ruling of the Court of Appeal on the question of the PUB's jurisdiction in this matter.

Directives 15 and 16 directed Manitoba Hydro to consider implementing recommendations made by the IECs with respect to Keeyask, MMTP and GNTL, as well as filing detailed quarterly reports for all Major New Generation and Transmission ("MNGT") projects currently under development. In response, Manitoba Hydro can advise that for those projects within the control of Manitoba Hydro, it has implemented certain recommendation and is still in the process of considering the implementation of others in order to properly assess any projected cost savings and schedule

Public Utilities Board — Régie des services publics

November 21, 2018

Ms. Odette Fernandes
Legal Counsel
Manitoba Hydro
22 – 360 Portage Avenue
Winnipeg, MB R3C 0G8

- and -

Past Interveners of Record (per attached list)

Re: Manitoba Hydro – Proposed 2019/20 General Rate Application

By letter of November 12, 2018, Manitoba Hydro ("Hydro") wrote to the Public Utilities Board ("Board") to advise of its intentions with respect to the filing of a 2019/20 General Rate Application ("GRA") and to seek comment from the Board as to Hydro's process proposal.

Background

Hydro's letter states that it intends to seek the Board's approval of a one-year rate increase, effective April 1, 2019, sufficient to generate a minimum level of net income such that Hydro would avoid a projected net loss in the 2019/20 fiscal year (the "test year"). Hydro advises it is not in a position to submit a long-term integrated financial forecast ("IFF"), but would file an application on the basis of its 2018/19 outlook (incorporating the actual financial position for electric operations as at March 31, 2018 and actual financial performance and water flow conditions to September 30, 2018) and interim 2019/20 budget (incorporating fall 2017 planning assumptions and operating expenditures). Hydro advises that both the 2018/19 outlook and 2019/20 budget are reflective of the Board's accounting directives in Order 59/18.

In its letter, Hydro proposes a written review process, with a limited number of information requests posed only by the Board's advisors and Intervener participation limited to written submissions.

The Board circulated Hydro's letter to and sought comments from past Interveners of Record ("Interveners"). The Board received comments on Hydro's letter from the Consumers Coalition, the Manitoba Industrial Power Users Group, Green Action Centre, and Assembly of Manitoba Chiefs.

Consideration of a One-Year 2019/20 GRA

Based on the Board's review of the comments received from Hydro and the Interveners, the Board has determined that it is willing to consider a one-year rate increase Application. Through the Board's consideration of Hydro's one-year rate increase Application, the Board will determine whether to approve a rate increase and the amount of any rate increase for any and all existing customer classes, including the First Nations On Reserve Residential customer class.

The Board recognizes that the one-year rate Application will be based on financial information for the 2018/19 and 2019/20 years, including the information listed in Hydro's letter.

The Board notes that, as Hydro intends to seek a final rate increase, Hydro must file financial and economic information sufficient to satisfy its onus to demonstrate that the rate increase sought for the test year is just and reasonable. This information should be the most current information available for the 2018/19 outlook and 2019/20 budget, and should be filed with an explanation as to why it is the most current information available. The Board expects that Hydro will include in its filing an update of the financial information for the 2019/20 test year contained in Exhibit MH-93 from the 2017/18 & 2018/19 GRA process, as revised to reflect the Board's directives in Order 59/18.

The scope of the issues can only be determined once Hydro has filed its application. At this preliminary stage, and without binding the Board to any decisions as to scope, the Board expects that the following issues may be deferred to a fulsome GRA process in late 2019:

- Review of 10 years of historical Operating and Administrative expense data,
- The results of an independent assessment of Hydro's asset management program, unless Directive 14 of Order 59/18 continues to be held in abeyance pending the Manitoba Court of Appeal decision or is overturned,
- Hydro's study of the Service Drop allocator and Common Costs,
- The status of the development of a time-of-use rate design proposal, including consultation measures undertaken and anticipated and/or scheduled next process steps,
- The finalization of interim diesel zone rates,
- The Solar Energy Program and other net metering installations, and
- Hydro's long-term financial forecast and financial plan.

<u>Process for a 2019/20 GRA</u>

Hydro states that it intends to submit its 2019/20 GRA filing by November 30, 2018.

The Board is not prepared to commit to a specific review process prior to receipt and review of the filing; however, on a preliminary basis and without binding the Board to any post-filing decisions on process, the Board has determined that it can accommodate Hydro's request that the review process be designed with the intention that a final rate increase, if any, be effective in the first quarter of Hydro's 2019/20 fiscal year. Such a review can include Intervener participation in the review, including in evidentiary process steps.

Pursuant to the Board's letter of September 18, 2018, the initial process for the Board's receipt of Hydro's proposed 2019/20 GRA will be as follows:

1. On receipt of Hydro's filing, Board staff and Advisors will review the filing for completeness of the information included in the filing;
2. If all routine, standard and/or base filing information is included in the filing in the form and presentation required by the Board, the Board will issue a declaration of completion. If the filing is determined to be incomplete, it will be returned to Hydro with direction as to the information required for completeness; and
3. Once the Board issues the declaration of completion, it will determine the post-filing process to be used for scoping the hearing and for the Board's review and consideration of the filing.

The Board notes that the draft Preliminary Issues List advanced to parties by the Board on July 20, 2018 was not issued as an interim Order. However, that Preliminary Issues List – revised as required to reflect the items that are expected to be deferred to a subsequent process – may provide guidance to Hydro regarding the required routine, standard, and/or base filing information for the proposed 2019/20 GRA.

Once the declaration of completion is issued, the Board will hold a half day Pre-Hearing Conference for the review and consideration of Intervener Applications and party submissions on the process for the 2019/20 GRA. The Board has set aside **December 19, 2018 from 11:30 am to 2:30 pm** for the Pre-Hearing Conference and asks that counsel hold that date, pending confirmation following the Board's issuance of the declaration of completion.

<u>Intervener Applications and Costs</u>

Should the Pre-Hearing Conference proceed on December 19, 2018, the deadline for Intervener Applications will be **Friday, December 14, 2018 at 4:00 pm.**

The Board has determined that the 2019/20 Hydro GRA will follow the process for Intervener Applications and Costs as set out in the attached Intervener Costs Policy, including the attached revised Intervener Application form and Intervener Costs Application spreadsheet. Questions in relation to these forms should be directed to Board Counsel.

Please address any other questions you may have at this time to the attention of the writer.

Yours truly,

"Original Signed By:"

Darren Christle, MPA, B.A., CCLP, P. Log., MCIT
Secretary/ Executive Director

DC/kls

Enclosures

cc: Liz Carriere, Manitoba Hydro
Shannon Gregorashuk, Manitoba Hydro
Bob Peters, Board Counsel
Dayna Steinfeld, Board Counsel

MANITOBA HYDRO

2019/20 ELECTRIC RATE APPLICATION

INDEX

Appendices

MANITOBA HYDRO
2019/20 ELECTRIC RATE APPLICATION

1.0 OVERVIEW AND REASONS FOR THE REQUESTED RATE INCREASE

On May 5, 2017, Manitoba Hydro filed a comprehensive 2017/18 & 2018/19 General Rate Application ("GRA") with the Public Utilities Board of Manitoba ("PUB") and a lengthy and extensive review of Manitoba Hydro's operations, forecasts, financial plans, capital expenditures, and operating expenses was conducted over the course of nine months. Following its review, the PUB issued Order 59/18, dated May 1, 2018, which approved a 3.6% average electric rate increase effective June 1, 2018. Order 59/18 also contained a number of directives and recommendations requiring work to be undertaken and completed by Manitoba Hydro prior to filing its next GRA.

With the appointment of a new Manitoba Hydro-Electric Board ("MHEB"), a comprehensive review of Manitoba Hydro's operations, forecasts and financial plans is currently being undertaken to allow the MHEB to establish a long-term financial plan for the Corporation. As a result of the foregoing, and further to Manitoba Hydro's correspondence of November 12, 2018 and the PUB's correspondence of November 21, 2018, Manitoba Hydro is submitting to the PUB a one-year rate increase application for the 2019/20 fiscal year which is based on financial information currently approved by the MHEB for the 2018/19 and 2019/20 fiscal years as set forth in its letter of November 12, 2018. Upon the MHEB's development and approval of a long-term financial plan, Manitoba Hydro will submit a full GRA to the PUB, anticipated to be filed in late 2019. A fulsome review of Manitoba Hydro's responses to those directives contained in Order 59/18 which the PUB indicated in its November 21, 2018 correspondence would be deferred, will also be addressed as part of the next GRA.

In this Application, Manitoba Hydro is requesting an Order pursuant to section 25(1) of *The Crown Corporations Governance and Accountability Act* for final approval of a 3.5% rate increase for all customer classes to be effective April 1, 2019. As shown in Appendix 1, page 1, this increase is projected to generate additional revenues of $59 million and would result in a modest contribution to financial reserves (net income) of $31 million in 2019/20. Absent the proposed rate increase for 2019/20, Manitoba Hydro is projecting a net loss of $28 million from Electric operations based on current assumptions.

As noted by the PUB in Order 59/18 (page 173):

> *The Integrated Financial Forecast filed in the proceeding as Manitoba Hydro Exhibit 93 supports the Board's decision on the level of the overall rate increase. This financial scenario included: continued deferral of $20 million in ineligible overheads, amortized at a 30-year rate; Average Service Life depreciation methodology, without amortization of the difference with the Equal Life Group methodology; achievement of a 25% equity level over a longer period of time, specifically by 2035/36; and debt management based on a weighted average term to maturity of 12 years. In many respects, and as a departure from Manitoba Hydro's plan and Integrated Financial Forecast assumptions, Manitoba Hydro Exhibit 93 is therefore reflective of many of the Board's decisions in this Order.*

Considering the MHEB is undertaking a comprehensive review of Manitoba Hydro's operations, forecasts and financial plans to allow for the establishment of a long-term financial plan for the Corporation, for purposes of its rate request for the 2019/20 fiscal year, Manitoba Hydro has noted the PUB's comment regarding Manitoba Hydro Exhibit 93 from the 2017/18 & 2018/19 GRA ("Exhibit 93") and prepared the current Application utilizing a comparison to Exhibit 93.

Since Order 59/18 was issued, Manitoba Hydro's cumulative earnings (actual and projected) over the three year period 2017/18 to 2019/20 have deteriorated by nearly $200 million compared to Exhibit 93 as shown in the following Figure 1.1.

The proposed 3.5% rate increase generated a more modest level of net income based on the lower water flow conditions at the time of the Application. However, the proposed 3.5% rate increase is aligned with the 3.6% rate increase granted in Order 59/18 as well as the projected 3.57% rate increases underlying Exhibit 93, and having regard for the expedited Application process, Manitoba Hydro determined it would accept the lower projected level of net income in its Application in favour of balancing the interests of ratepayers and their bill impacts.

The deterioration in water flow conditions over the 2018 summer described in the Application has been followed by a rapid turnaround in the two months since filing the Application. This demonstrates the extreme variability in earnings Manitoba Hydro can experience over a short period of time. The $115 million in net income currently projected for 2019/20 is based on average net export revenues under all water flow records, and as demonstrated by the recently experienced variability, the likelihood of actual financial results being precisely $115 million for 2019/20 is low. Under less extreme water flow conditions (the 80th and 20th percentiles), net income could be $75 million higher or lower than projected for 2019/20. However, based on the highest and lowest water flows on record, net income could vary as much as $110 million higher or $350 million lower for 2019/20. Under low water flow conditions, a reduction to the 3.5% rate increase would increase the likelihood of a financial loss in 2019/20.

The proposed 3.5% rate increase continues to allow Manitoba Hydro to plan for a modest level of net income in the event of low water flow conditions. Waiting until low water flows occur and providing rate relief after the fact would result in permanent incremental debt and associated financing costs that must be passed through to customers. Further, given the increase in costs attributable to the in-service of Bipole III as well as the anticipated additional net costs associated with the in-service of Keeyask, a financial loss in 2019/20 could result in the exacerbation of financial losses projected in Exhibit 93 and the requirement for significantly higher rate increases in the period following Keeyask in-service. Granting a 3.5% rate increase as requested in this Application reduces the likelihood of future rate shock to ratepayers.

REFERENCE:

Current Application p. 1, PUB/MH I-3 (a) (b) (c)

PREAMBLE TO IR (IF ANY):

In its letter to the PUB of August 15, 2018, MH acknowledged that it was in a position to submit a GRA notwithstanding any clear guidance from the PUB on reserve maintenance or any other financial metrics that the PUB will consider in rate-setting (last paragraph page 2). On page 1 of the current application, MH indicates that with the appointment of a new MHEB (in March and June of 2018 per MH's letter to PUB of November 12, 2018), a comprehensive review of MH's operations, forecasts and financial plans is currently being undertaken to allow the MH to establish a long-term financial plan. Upon the MHEB's development and approval of a long-term financial plan, MH will submit a full GRA as well as a fulsome review of responses to PUB directives from Order 59/18, which is anticipated to be filed in late 2019.

QUESTION:

a) Please explain the reason for the change in MH's position with respect to its ability to produce/file an IFF/GRA in August of 2018 with the position taken in MH's letter of November 12, 2018 and 2019/20 rate application of November 30, 2018?
b) Please explain why MH has not provided any information with respect to the macro-economic impacts/impacts on vulnerable consumers of the proposed rate increase in accordance with PUB expectations outlined on page 172 of Order 59/81 that in future rate applications, MH is to assess the broader impacts of rate increases beyond only its financial health (response to PUB/MH I-3 (a) (b) (c))?

RATIONALE FOR QUESTION:

To further understand the special circumstances surrounding the 2019/20 rate application and the plans outlined by MH in terms of filing a comprehensive GRA late in 2019. Manitoba Hydro's future plans regarding the MHEB review and its 2020/21 GRA is relevant to the issue of the impact of the increase on consumers.

RESPONSE:

a) The question posed does not accurately characterize Manitoba Hydro's comments in its August 15, 2018 letter. In its August 15th correspondence, Manitoba Hydro indicated that:

"Manitoba Hydro acknowledges it is in a position to submit a GRA notwithstanding any clear guidance from the PUB on reserve maintenance or other any other financial metrics that the PUB will consider in rate-setting. Manitoba Hydro's submission is that it is unavailing and inefficient to do so and that all Parties, including the PUB, should obtain the benefit of the further discussion and dialogue on these important matters enabled by the technical conference."

This was intended to communicate that Manitoba Hydro was not of the opinion that it was precluded from filing a GRA in the absence of a PUB finding on financial metrics, although it acknowledged that such a filing would result in parties revisiting a number of the issues canvassed in the 2017/18 and 2018/19 GRA. These comments were not intended to imply that Manitoba Hydro was, in August 2018, in a position to file a GRA at that time. While the PUB no longer plans to hold a technical conference on financial targets, as noted in subsequent correspondence and in the current Application, the new MHEB must establish the long-term financial plan and targets for the Corporation prior to preparation of the next Integrated Financial Forecast. This IFF, when approved, will form the basis for the next General Rate Application.

The current Electric Rate Application is intended to ensure that the financial stability of the Corporation does not deteriorate further prior to completion of this exercise and preparation of the related long-term forecasts. While Keeyask final costs and other planning assumptions are uncertain at this time, what is known is that when Keeyask comes into service it will require over $300 million in net carrying costs, which revenues at current approved PUB rates are not sufficient to cover (see the response to COALITION/MH I-1). A 3.5% rate increase effective June 1, 2019 will serve to mitigate the risk that the utility and its stakeholders be required to impose significant rate increases on consumers in future years.

b) The response to PUB/MH I-3 provides details of the consultations and customer communications Manitoba Hydro has engaged in as well as information related to customer satisfaction with all aspects of electrical service. With respect to the macro-economic impacts of the proposed rate increase, Manitoba Hydro has previously advised the PUB and interested parties that an assessment of macroeconomic impacts of utility rate increases on the Province requires consideration of the behavior and performance of the economy of Manitoba as a whole. This is not information which Manitoba Hydro possesses or studies, nor is it in a position to provide same. This type of information has not been filed in previous GRA's and has not historically been considered by the PUB in establishing rates. The assessment or consideration of any macroeconomic impacts of a proposed rate increase on the Provincial economy goes far beyond the balancing of interests of ratepayers and the utility and into the realm of government. Such an assessment is not contemplated either in the *Manitoba Hydro Act (s. 39)* or the *Crown Corporations Governance and Accountability Act (s. 25(4))* as a factor to be considered in establishing just and reasonable rates for utility service.

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Figure 1.1: Comparison of Actual and Projected Net Income to Exhibit 93
(In Millions of Dollars)

	2017/18	2018/19	2019/20	Total
Actual & Projected Net Income	18 [1]	51 [2]	31 [3]	100
Exhibit 93 Net Income [4]	94	143	61	298
Increase/(Decrease)	(75)	(93)	(30)	(198)

[1] 2017/18 Actual net income (Section 2.1)
[2] 2018/19 Financial Outlook (Section 2.3)
[3] 2019/20 Interim Budget including 3.5% proposed rate increase (Section 2.4)
[4] Includes a projected 3.57% rate increase

Actual net income results for 2017/18 were lower than anticipated in Exhibit 93 mainly due to lower export prices, the impact of U.S. transmission outages which led to lower volumes and a higher proportion of off peak sales at lower prices, as well as higher net finance costs.

The outlook for 2018/19 net income is also much lower compared to Exhibit 93 which is primarily attributable to lower net export revenues as a result of below average water conditions impacting generation, as well as increases in depreciation and financing costs arising from the earlier than planned in-service of Bipole III, which went into service July 4, 2018 compared to a budgeted in-service date of July 31, 2018.

Exhibit 93 projected net income of $61 million for electric operations for the 2019/20 fiscal year. In comparison, the 2019/20 Interim Budget, which includes the proposed 3.5% rate increase requested in this application, projects net income of $31 million. The deterioration in projected net income for electric operations is mainly attributable to higher net financing costs. Exhibit 93 had assumed that Manitoba Hydro could take advantage of lower interest costs on debt issues with shorter terms to maturity. Since the 2017/18 & 2018/19 GRA, the interest rate yield curve has continued to flatten and the savings expected from shorter term borrowings are no longer available.

2.0 REASONS FOR THE RATE INCREASE

Manitoba Hydro is currently projecting net income of $95 million for 2018/19 and $115 million for 2019/20. This compares to the projected net income in the Application of $51 million for 2018/19 and $31 million for 2019/20. The improvement in financial results is due to higher net export revenues resulting from improved water flow conditions, as well as lower levels of capital spending than planned in 2018/19 and the associated lower borrowing requirements and finance expense. Sections 2 and 3 below provide further analyses of the updated forecast revenues and expenses related to Manitoba Hydro's electric operations for 2018/19 and 2019/20, and Section 4 provides an overview of the updated Capital Expenditure Forecast for 2018/19 and 2019/20. Revised financial statements can be found in Appendix 1 Updated to the Application.

Although projected financial results have improved since filing the Application, Manitoba Hydro submits that the 3.5% proposed rate increase continues to be necessary and in the public interest. The following Figure 1 provides a comparison of the revised financial results to Exhibit 93. Figure 1 shows that actual and projected results continue to be $70 million below those forecast in Exhibit 93, inclusive of 3.57% rate increases in each of 2018/19 and 2019/20, which was relied upon by the PUB in approving a 3.6% rate increase for 2018/19 in Order 59/18. Manitoba Hydro is providing as Appendix 14 an update to Figures 2.4 and 2.5 of the Application filed on November 30, 2018, comparing the 2018/19 Current Outlook and 2019/20 Approved Budget with Exhibit 93.

Figure 1: Comparison of Actual and Projected Net Income to Exhibit 93
(In Millions of Dollars)

	2017/18	2018/19	2019/20	Total
Actual & Projected Net Income	18 [1]	95 [2]	115 [3]	228
Exhibit 93 Net Income [4]	94	143	61	298
Increase/(Decrease)	(75)	(48)	54	(70)

[1] 2017/18 Actual net income
[2] 2018/19 Current Outlook (Section 2.0)
[3] 2019/20 Approved Budget including 3.5% proposed rate increase effective June 1/19 (Section 3.0)
[4] Includes a projected 3.57% rate increase effective April 1 of 2018 and 2019

Comparison of Actual and Projected Net Income to Exhibit 93 at 20 WATM
(In Millions of Dollars)

	2017/18	2018/19	2019/20	Total
Actual & Projected Net Income	18 [1]	95 [2]	115 [3]	228
Exhibit 93 Net Income - 20 WATM [4]	90	123	28	241
Increase/(Decrease)	(72)	(28)	87	(13)

[1] 2017/18 Actual net income

[2] 2018/19 Current Outlook (Section 3.0) - Supplement to the 2019/20 Electric Rate Application

[3] 2019/20 Approved Budget including 3.5% proposed rate increase effective June 1/19 (Section 4.0) - Supplement to the 2019/20 Electric Rate Application

[4] Includes a projected 3.57% rate increase effective April 1 of 2018 and 2019

Excluding 2017/18, the cumulative actual and projected net income would be $59 million higher than Exhibit 93 assuming a 20 year WATM and rate increases of 3.57% on April 1, 2018 and April 1, 2019. As shown in Figure 1 (page 2) of the Supplement to the 2019/20 Electric Rate Application, the cumulative actual and projected net income is $70 million lower than Exhibit 93 assuming a 12 year WATM.

b) Please see Attachment 1 for the financial ratio calculations for i) MH Exhibit 93 from the 2017/18 and 2018/19 GRA, and for ii) MH Exhibit 93 with 2018/19 and 2019/20 reflecting 20-year WATM.

c) Please see Appendix 16 for a copy of the Quarterly Report for the six months ending September 30, 2017. In the Second Quarter report, the Corporation was projecting a consolidated net income for 2017/18 of $40 million compared to the approved annual budget of $122 million. The decrease in projected net income was due to receiving the lower than requested rate increase, a continuation of weak opportunity export prices, a relatively dry summer impacting water flow conditions and higher financing costs. The $40 million outlook for net income for 2017/18 assumed average water flow conditions and normal winter weather for the remainder of the year.

d) An Interim Budget was utilized for purposes of the 2019/20 Electric Rate Application as the timeline to submit a rate request for 2019/20 did not align with the Corporation's

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Figure 2.9: 2019/20 Interim Budget with and without the 3.5% Revenue Increase

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

	Interim Budget (3.50%)	**Interim Budget (0.00%)**	**Increase/ (Decrease)**
For the year ended March 31		**2020**	
REVENUES			
Domestic Revenue	1 737	1 678	59
BPIII Reserve Account	78	78	-
Extraprovincial	411	411	-
Other	29	29	-
	2 255	2 196	59
EXPENSES			
Operating and Administrative	511	511	-
Net Finance Expense	765	765	(1)
Depreciation and Amortization	508	508	-
Water Rentals and Assessments	111	111	-
Fuel and Power Purchased	160	160	-
Capital and Other Taxes	150	150	0
Other Expenses	111	111	-
Corporate Allocation	8	8	-
	2 325	2 325	(1)
Net Income before Net Movement in Reg. Deferral	(70)	(129)	59
Net Movement in Regulatory Deferral	103	103	-
Net Income	33	(26)	59
Net Income Attributable to:			
Manitoba Hydro	**31**	**(28)**	**59**
Non-controlling Interest	2	2	0
	33	(26)	59
Percent Increase	3.50%	0.00%	

2.4.4 2019/20 Sensitivity Analysis

This section provides an indication of the impact of changes in water flow conditions, weather, interest rates and export prices on the 2019/20 Interim Budget net income of $31 million.

Figure 7: 2019/20 Approved Budget with and without the 3.5% Rate Increase

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

	Approved Budget (3.50%)	Approved Budget (0.00%)	Increase/ (Decrease)
For the year ended March 31		**2020**	
REVENUES			
Domestic Revenue	1 749	1 699	50
BPIII Reserve Account	78	78	-
Extraprovincial	418	418	-
Other	27	27	-
	2 272	2 222	50
EXPENSES			
Operating and Administrative	511	511	-
Net Finance Expense	741	742	(1)
Depreciation and Amortization	505	505	-
Water Rentals and Assessments	117	117	-
Fuel and Power Purchased	127	127	-
Capital and Other Taxes	148	148	0
Other Expenses	74	74	-
Corporate Allocation	8	8	-
	2 232	2 233	(1)
Net Income before Net Movement in Reg. Deferral	40	(11)	51
Net Movement in Regulatory Deferral	71	71	-
Net Income	111	60	51
Net Income Attributable to:			
Manitoba Hydro	**115**	**64**	**51**
Non-controlling Interest	(4)	(4)	0
	111	60	51
Percent Increase	3.50%	0.00%	

4.0 2018/19 & 2019/20 CAPITAL EXPENDITURE FORECAST

Figure 8 provides a comparison of current forecast of capital expenditures for 2018/19 and 2019/20 compared to the Application filed on November 30, 2018.

Figure 3: 2019/20 Approved Budget Compared to the 2019/20 Interim Budget filed on November 30, 2018 for Electric Operations

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

	Approved Budget	Interim Budget	Increase/ (Decrease)
For the year ended March 31		2020	
REVENUES			
Domestic Revenue	1 749	1 737	12
BPIII Reserve Account	78	78	0
Extraprovincial	418	411	7
Other	27	29	(2)
	2 272	2 255	17
EXPENSES			
Operating and Administrative	511	511	0
Net Finance Expense	741	765	(24)
Depreciation and Amortization	505	508	(3)
Water Rentals and Assessments	117	111	6
Fuel and Power Purchased	127	160	(33)
Capital and Other Taxes	148	150	(2)
Other Expenses	74	111	(37)
Corporate Allocation	8	8	-
	2 232	2 325	(92)
Net Income before Net Movement in Reg. Deferral	40	(70)	110
Net Movement in Regulatory Deferral	71	103	(32)
Net Income	111	33	77
Net Income Attributable to:			
Manitoba Hydro	**115**	**31**	**84**
Non-controlling Interest	(4)	2	(6)
	111	33	77

The increase in net income of $84 million is primarily attributable to lower fuel and power purchases, lower net finance expense and a slightly higher electric load forecast. The decrease of $33 million in Fuel and Power Purchased is due to a higher starting water storage levels and more storage drawn down through the 2019/20 fiscal year resulting in more hydraulic generation, less opportunity import purchases and a reduction to the amount of thermal generation.

The decrease of $24 million to Net Finance Expense is primarily due to lower projected debt issuances as a result of a lower capital requirements in 2018/19 offset partially by a weakening of the Canadian dollar.

The increase of $12 million to Domestic Revenue reflects slightly higher domestic energy requirements largely due to a delay in the implementation of planned DSM programs as a result of the ongoing transition to Efficiency Manitoba. This is partially offset by a deferral of the 3.5% proposed rate increase to June 1, 2019 from April 1, 2019 which reflects the current regulatory schedule.

The decrease in Other Expenses of $37 million reflects lower planned DSM expenditures and is mainly offset in the Net Movement in Regulatory Deferrals.

As with the 2018/19 Current Outlook, the 2019/20 Approved Budget is exposed to the same uncertainty and variability inherent in the forecast of net interchange revenues and generation costs, the impacts of changes to the major projects construction schedules, estimates on cash requirements and finance expense. While the 2019/20 Approved Budget has improved by $84 million compared to the Interim Budget filed in November 2018, the variability of any one (or combination of) multiple risks contained in Figure 2.10 (page 26) in the November 30th Application continue to exist.

As previously discussed in Section 2.0 and shown in Figure 4 below, changes in water flow conditions alone can shift net income by +$110 million under the highest flow condition on record to -$350 million under the lowest flow condition on record. Even if the extreme outliers are excluded and a more narrow range is considered (20th to 80th percentiles), the potential range in net export revenue remains significant at +/-$75 million from average.

	Feb 14 Approved Budget	MH-93 20 Yr WATM	Increase/ (Decrease)
Revenues			
Domestic Revenue	1749	1720	29
BPIII Reserve	78	79	-1
Extraprovincial	418	420	-2
Other	27	31	-4
Total	2272	2251	21
Expenses			
O&A	511	511	0
Net Finance Expense	741	754	-13
Depreciation	505	515	-10
Water Rentals	117	110	7
Fuel & Power Purchases	127	158	-31
Capital and Other Taxes	148	154	-6
Other Expenses	74	481	-407
Corporate Allocation	8	8	0
Total	2232	2693	-461
Net Income Before Net Movement	40	(442)	482
Net Movement	71	473	-402
Net Income	111	30	81
Net Income Attributable to MH	**115**	**28**	**87**

Sources February 14 Supplement Figure 3; Coalition/MH 1-6b Attachment 1 Figure 5

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
REVENUES			
Domestic Revenue			
at approved rates	1 616	1 703	1 699
additional	-	-	50
BPIII Reserve Account	(152)	(44)	0
Extraprovincial	437	432	418
Other	30	85	105
	1 931	2 175	2 272
EXPENSES			
Operating and Administrative	517	501	511
Net Finance Expense	578	712	741
Depreciation and Amortization	402	465	505
Water Rentals and Assessments	126	114	117
Fuel and Power Purchased	130	135	127
Capital and Other Taxes	130	140	148
Other Expenses	501	79	74
Corporate Allocation	8	8	8
	2 393	2 154	2 233
Net Income before Net Movement in Reg. Deferral	(462)	22	40
Net Movement in Regulatory Deferral	472	70	70
Net Income	10	92	110
Net Income Attributable to:			
Manitoba Hydro	**18**	**95**	**115**
Non-controlling Interest	(8)	(3)	(4)
	10	92	110
PUB Approved Percent Increase	3.36%	3.60%	-
Proposed Percent Increase	-	-	3.50%
Financial Ratios			
Equity	14%	14%	13%
EBITDA Interest Coverage	1.46	1.59	1.61
Capital Coverage	0.46	1.26	1.34

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**ACTUAL 2018**	**CURRENT OUTLOOK 2019**	**APPROVED BUDGET 2020**
ASSETS			
Plant in Service	13 681	18 528	19 134
Accumulated Depreciation	(1 302)	(1 715)	(2 171)
Net Plant in Service	12 380	16 813	16 963
Construction in Progress	8 995	6 261	7 658
Current and Other Assets	1 792	1 913	2 141
Goodwill and Intangible Assets	440	648	857
Total Assets before Regulatory Deferral	23 607	25 635	27 619
Regulatory Deferral Balance	933	955	1 025
	24 540	26 590	28 644
LIABILITIES AND EQUITY			
Long-Term Debt	17 813	20 709	21 530
Current and Other Liabilities	3 777	2 941	4 095
Provisions	60	48	47
Deferred Revenue	467	486	495
BPIII Reserve Account	294	255	177
Retained Earnings	2 767	2 862	2 977
Accumulated Other Comprehensive Income	(688)	(711)	(675)
Total Liabilities and Equity before Regulatory Deferral	24 491	26 590	28 644
Regulatory Deferral Balance	49	-	-
	24 540	26 590	28 644

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

For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
OPERATING ACTIVITIES			
Net Income	10	92	110
Add Back:			
Depreciation and Amortization	402	465	505
Net Finance Expense	578	712	741
Net Movement Impacts on Depreciation and Finance Expense	3	21	23
Adjustments for Non-Cash Items	(12)	17	(3)
Adjustments for Non-Cash Working Capital Accounts	(256)	(32)	(34)
Interest Paid	(880)	(964)	(1 028)
Interest Received	23	14	16
Cash Provided by Operating Activities	(132)	326	331
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt	3 441	3 852	2 150
Retirement of Long-Term Debt	(583)	(1 775)	(227)
Repayments from/(Advances to) External Entities	(57)	(52)	(45)
Proceeds from Partnership Issuances	44	51	44
Sinking Fund Withdrawals	165	193	130
Sinking Fund Payment	(165)	(193)	(214)
Other	(11)	-	-
Cash Provided by Financing Activities	2 833	2 076	1 838
INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2 610)	(1 933)	(1 735)
Additions to Intangible Assets	(133)	(219)	(207)
Additions to Regulatory Deferral Balances	(93)	(93)	(94)
Contributions Received	194	62	13
Cash Paid to the City of Winnipeg	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(104)	(69)
Other	(3)	(1)	(0)
Cash Used for Investing Activities	(2 706)	(2 303)	(2 110)
Net Increase (Decrease) in Cash	(4)	98	59
Cash at Beginning of Year	634	579	678
Cash at End of Year	629	678	737

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

For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
OPERATING ACTIVITIES			
Cash Receipts from Customers	1 883	2 111	2 187
Cash Paid to Suppliers and Employees	(1 158)	(836)	(843)
Interest Paid	(880)	(964)	(1 028)
Interest Received	23	14	16
Cash Provided by Operating Activities	(132)	326	331
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt	3 441	3 852	2 150
Retirement of Long-Term Debt	(583)	(1 775)	(227)
Repayments from/(Advances to) External Entities	(57)	(52)	(45)
Proceeds from Partnership Issuances	44	51	44
Sinking Fund Withdrawals	165	193	130
Sinking Fund Payment	(165)	(193)	(214)
Other	(11)	0	0
Cash Provided by Financing Activities	2 833	2 076	1 838
INVESTING ACTIVITIES			
Additions to Capital Assets	(2 610)	(1 933)	(1 735)
Additions to Intangible Assets	(133)	(219)	(207)
Additions to Regulatory Deferral Balances	(93)	(93)	(94)
Contributions Received	194	62	13
Cash Paid to the City	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(104)	(69)
Other	(3)	(1)	(0)
Cash Used for Investing Activities	(2 706)	(2 303)	(2 110)
Net Increase (Decrease) in Cash	(4)	98	59
Cash at Beginning of Year	634	579	678
Cash at End of Year	629	678	737

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REFERENCE:

Application p. 23, 26; 2017/18 GRA Supplement to Tab 3

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update Figures 4 (Daily Hydraulic Energy from Inflow) and 6 (Total Hydraulic Generation) in the Supplement to Tab 3 from the 2017/18 GRA. Figure 6 should include 2017/18 actual results, as well as the generation resulting from the range of historical flows and the 50% confidence levels of generation for both 2018/19 and 2019/20.

RESPONSE:

Please see figures below. Note that for completeness, this response also includes an update to Figure 5 (Total Energy in Reservoir Storage). Figures 4 and 5 have been updated to include recent data.

Figure 4. Daily Hydraulic Energy from Inflow

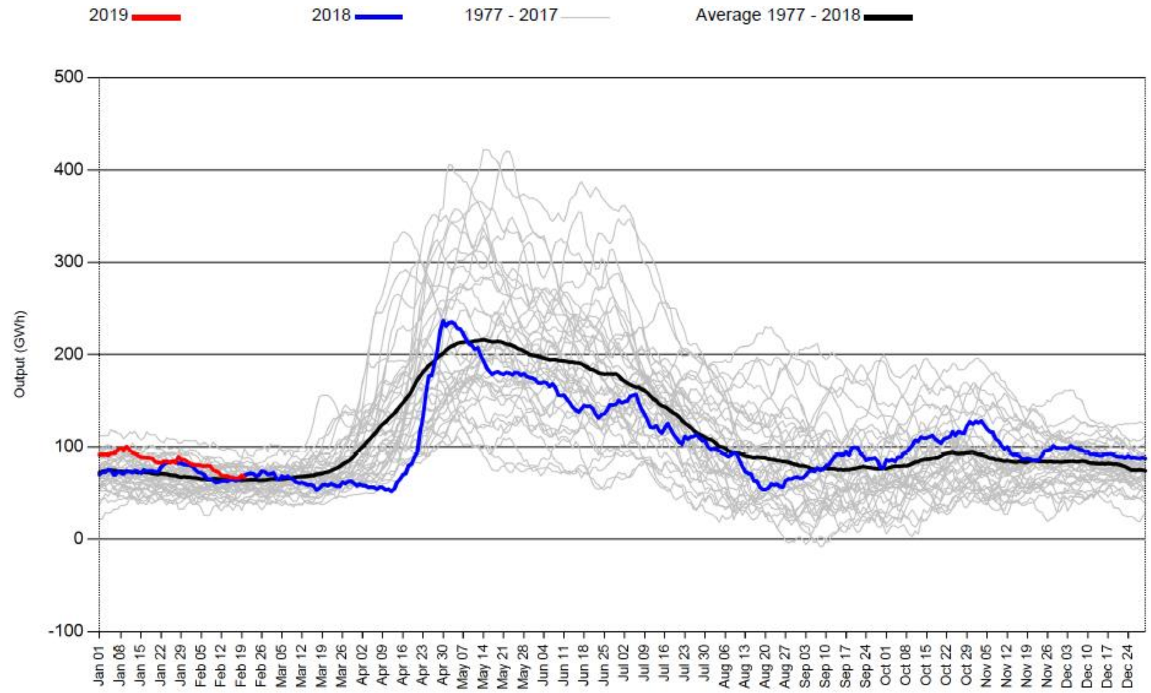


Figure 5. Total Energy in Reservoir Storage

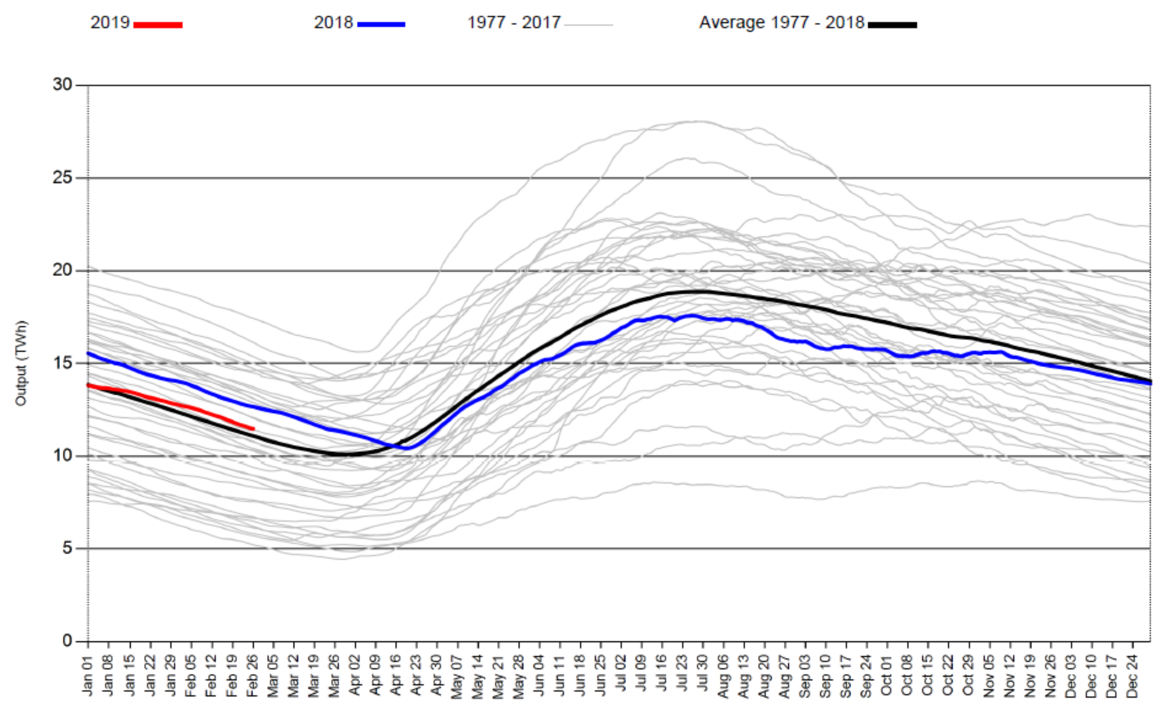
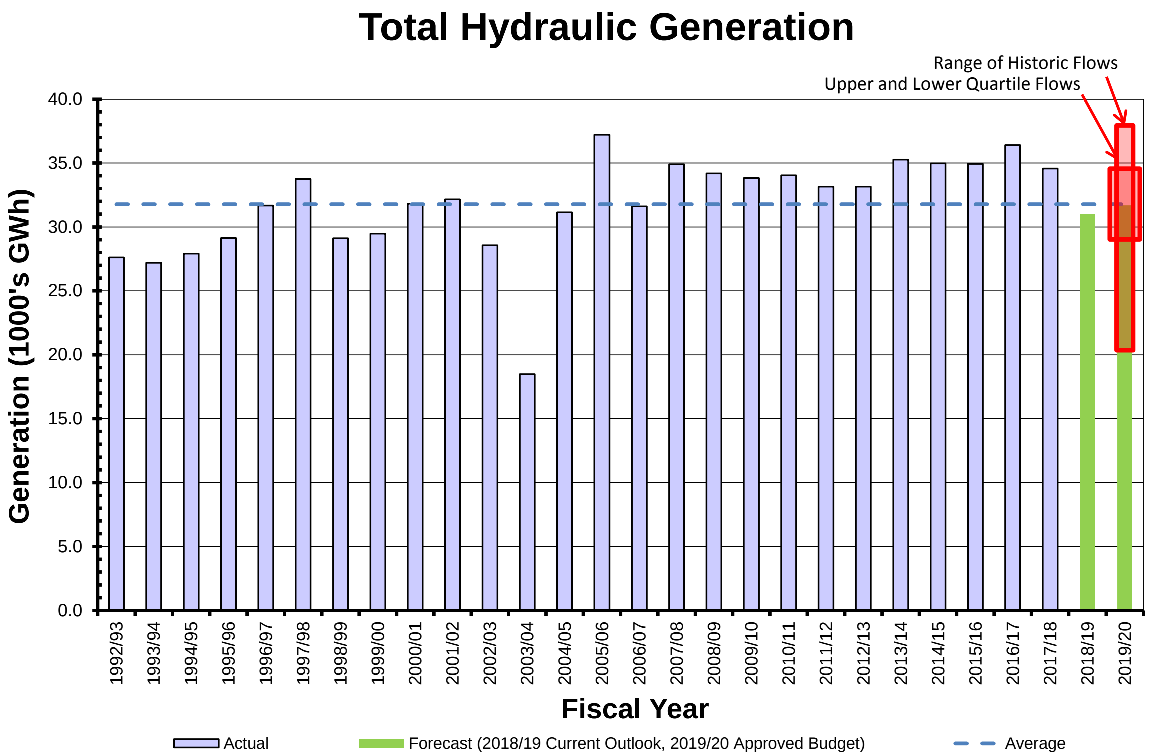


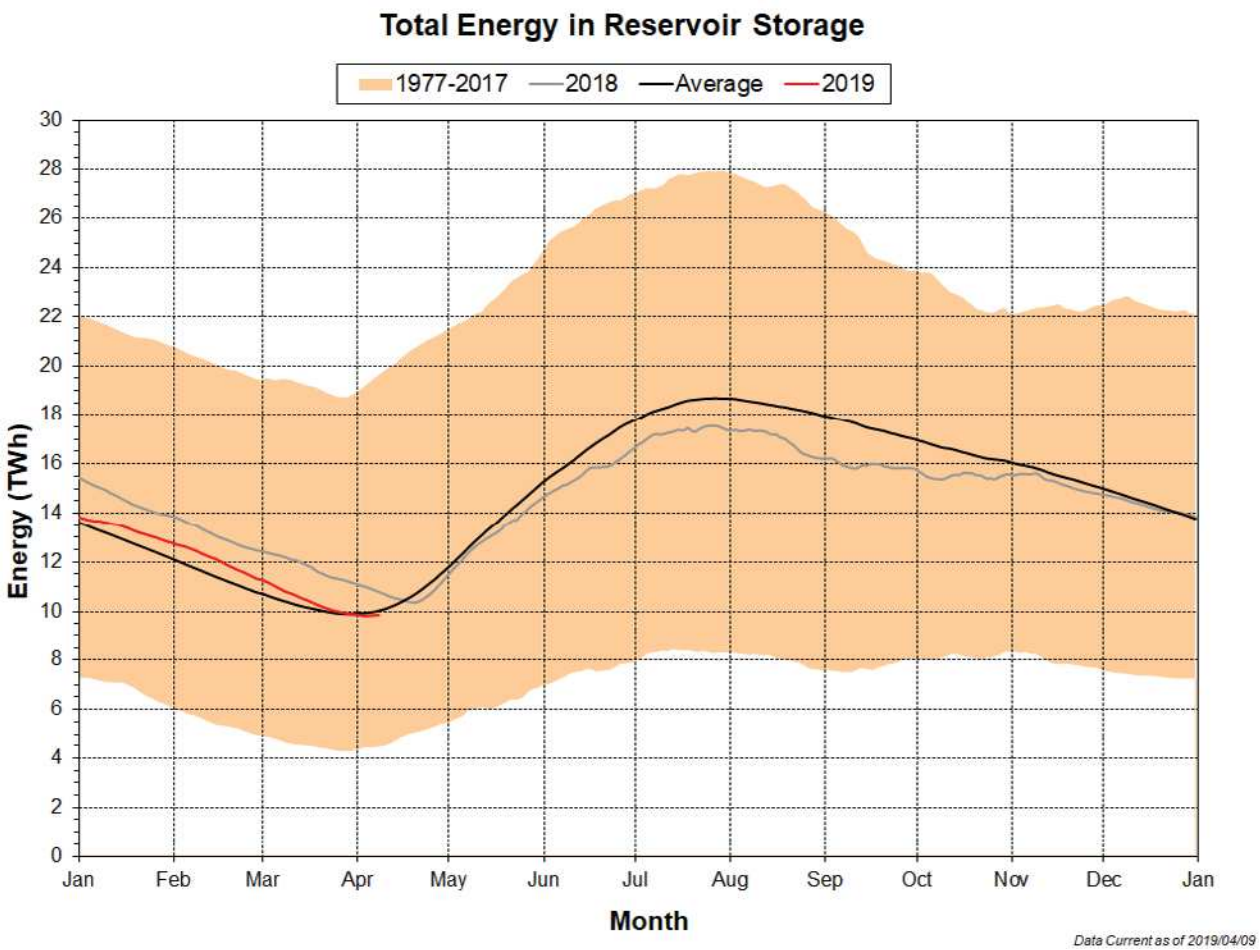
Figure 6. Total Hydraulic Generation



The full range of historical inflow was not used in preparing the 2018/19 Current Outlook. Simulation of hydroelectric generation for the 2018/19 Current Outlook was prepared in January of 2019 when there was relative certainty of inflows for the remainder of the fiscal year, as compared to when forecasts are prepared early in or prior to the beginning of the fiscal year. Only a single expected inflow scenario was used in preparing the 2018/19 Current Outlook. Hydraulic generation derived from that inflow scenario is plotted in Figure 6.

The 2019/20 Approved Budget is based on simulations using the 105 year flow record (1912/13 through 2016/17). The upper and lower quartile, maximum and minimum hydraulic generation values are plotted in Figure 6.

Chart (b) - Energy in Storage



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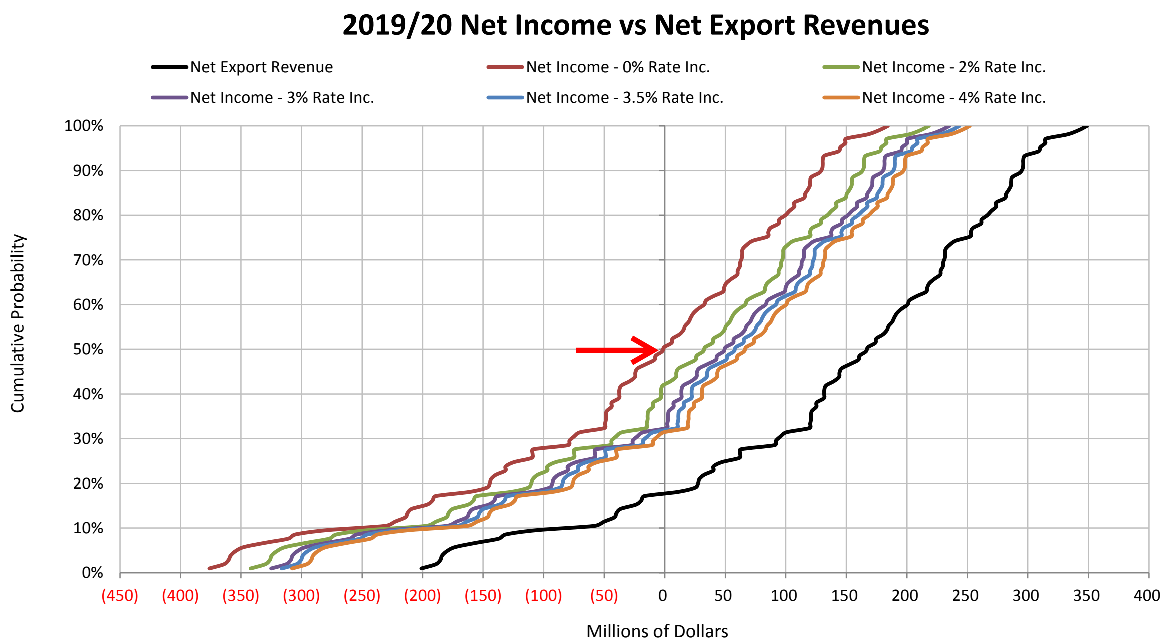
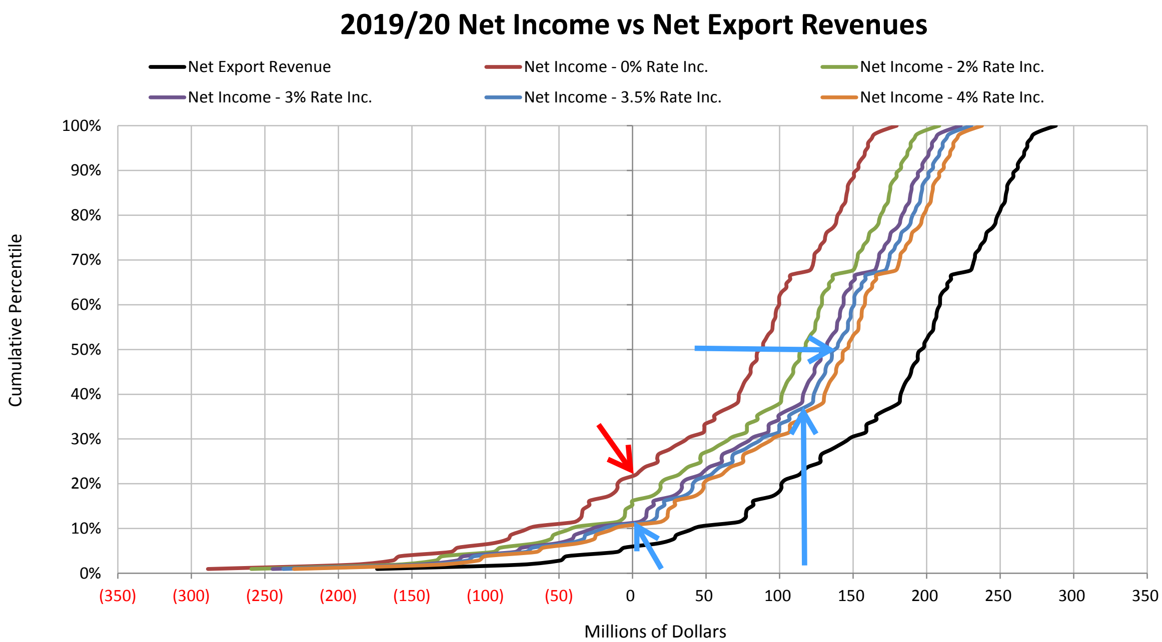
c) The following graph contains the 2019/20 net export revenue based on 105 historical water flows as well as the resulting electric net income using the following rate increase assumptions for 2019/20: 0%, 2%, 3%, 3.5% and 4%. The data has also been provided in tabular format below.



From the above graph, it can be observed that:

- With a 0% rate increase in 2019/20, there is a 50% chance that the Corporation will experience net losses. Using the 0% rate increase assumption, net income ranges between a net loss of $125 million and a positive net income of $85 million between the P25 and P75 bounds.
- Assuming the applied for 3.5% rate increase, there is roughly a 30% chance that the Corporation will experience net losses in 2019/20. Using the 3.5% rate increase assumption, 2019/20 net income ranges between a net loss of $65 million and a positive net income of $145 million between the P25 and P75 bounds.

c) The following graph contains the 2019/20 net export revenue based on 105 historical water flows as well as the resulting electric net income using the following rate increase assumptions for 2019/20: 0%, 2%, 3%, 3.5% and 4%. The data has also been provided in tabular format below.



From the above graph, it can be observed that:

- With a 0% rate increase in 2019/20, there is a 21% chance that the Corporation will experience net losses. Using the 0% rate increase assumption, net income ranges between $17 million and $131 million between the P25 and P75 bounds.
- Assuming the applied for 3.5% rate increase, there is roughly a 10% chance that the Corporation will experience net losses in 2019/20. Using the 3.5% rate increase assumption, 2019/20 net income ranges between $68 million and $182 million between the P25 and P75 bounds.

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The net income or loss resulting under each of the key changes in assumptions is shown below in Figure 2.10. Figure 2.10 also shows that the likelihood of a financial loss is greater without the proposed 3.5% rate increase under the range of sensitivities considered.

Figure 2.10: Key Variable Sensitivity Impacts on 2019/20 Interim Budget Net Income/ (Loss) With and Without the 3.5% Proposed Rate Increase

	Projected Net Income/(Loss)	
	3.5% Proposed Rate Increase	**No Rate Increase**
Interim 2019/20 Budget	$31 M	($28) M
Low Water Flow (10^{th} percentile net interchange revenues and generation costs)	($169) M	($229) M
High Water Flow (90^{th} percentile net interchange revenues and generation costs)	$194 M	$134 M
Colder than normal winter weather	$63 M	$4 M
Warmer than normal winter weather	($0) M	($60) M
+ 1% Interest Rates	$16 M	($43) M
- 1% Interest Rates	$45 M	($14) M
Low Export Price Case	($2) M	($61) M
High Export Price Case	$49 M	($10) M

The 2019/20 Interim Budget assumes average net interchange revenues and generation costs for the historic water flow record. The historic water flow record has a great deal of variability from the highest to the lowest flow which creates a dramatic range of the possible net interchange revenues and generation costs that could occur in a given year. The impact of low flows are greater than high flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high flow years. Due to this asymmetry, the average revenues and costs of the historic water flow record is the equivalent to approximately the 40^{th} percentile or P40 and not the median or P50. To demonstrate the range of possible net interchange revenues and generation costs, the P10 and P90 sensitivities have been provided. Figure 2.10 shows that the

b) Figure 2.10 has been updated for the 2019/20 Approved Budget and includes the impacts of the 20th and 80th percentile water flow scenarios on the proposed 3.5% rate increase as well as 0%, 1.0% and 2.0% rate increase scenarios (all assuming a June 1st, 2019 rate increase implementation). The table below excludes the +/- 1% interest rate sensitivity as the November 30, 2018 filing assumed all new debt issues in 2018/19 and 2019/20 were impacted by a change in the forecasted interest rates.

Since actual debt issuances have been locked-in to December 31, 2018, the financial impacts to the 2019/20 Approved Budget are reduced since there is a smaller volume of new debt issuances exposed to fluctuations in interest rates. However, the full year's impact of a change in interest rates (+/-$15 million) would be realized in the 2020/21 fiscal year.

	Projected Net Income/(Loss)			
	3.5% Proposed Rate Increase	**No Rate Increase**	**1.0% Rate Increase**	**2.0% Rate Increase**
Approved 2019/20 Budget	$ 115 M	$ 64 M	$ 78 M	$ 93 M
Low Water Flow (10th percentile net interchange revenues and generation costs)	($ 23) M	($ 75) M	($ 60) M	($ 45) M
High Water Flow (90th percentile net interchange revenues and generation costs)	$ 202 M	$ 150 M	$ 165 M	$ 179 M
Low Water Flow (20th percentile net interchange revenues and generation costs)	$ 41 M	($ 10) M	$ 4 M	$ 19 M
High Water Flow (80th percentile net interchange revenues and generation costs)	$ 191 M	$ 139 M	$ 154 M	$ 168 M
Colder than normal winter weather	$ 161 M	$ 110 M	$ 124 M	$ 139 M
Warmer than normal winter weather	$ 66 M	$ 15 M	$ 30 M	$ 44 M
Low Export Price Case	$ 91 M	$ 39 M	$ 54 M	$ 68 M
High Export Price Case	$ 188 M	$ 136 M	$ 151 M	$ 165 M

c) The sensitivities as shown in Figure 2.10 highlight those assumptions which have the most significant variability on Manitoba Hydro's financial results as compared to the Approved Budget. The budgets for domestic revenue, net export revenue and finance expense are calculated based on historical analysis of weather and water flow conditions as well as future economic variables including projected export prices and

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Manitoba Hydro

Manitoba Hydro 2019/20 Electric Rate Application
PUB/MH I-9 (Updated)

KEEYASK (ISD 2021/22)
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	-	-	-	119	329
OM&A Costs	-	-	-	9	16
Depreciation	-	-	-	21	99
Capital Tax	29	35	39	42	43
Water Rentals	-	-	-	5	14
	29	35	39	196	502

MANITOBA-MINNESOTA TRANSMISSION PROJECT
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	0	1	11	22	21
OM&A Costs	-	-	-	0	0
Depreciation	0	0	5	7	7
Transmission Charges	-	-	-	-	-
Capital Tax	1	2	2	2	2
	1	3	19	31	31

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31

	2019	2020	2021	2022	2023
Finance Expense	[redacted]				
OM&A Costs					
Amortization					
Transmission Charges					
Capital Tax					
	2	3	74	99	97

3a

address the anticipated additional net costs associated with the in-service of Keeyask, MMTP and GNTL.

The following is an illustrative example of the impact to net income once these facilities are placed in-service. The example assumes revenues and expenses at 2019/20 levels plus the additional revenues and costs of Keeyask, MMTP and GNTL as projected in 2022/23. The deficit of approximately $300 million as shown in the table below would require a one-time rate increase of 18% in order to break even.

Without the 3.5% Rate Increase in 2019/20	
Total Revenues (Figure 7)	2,222
KHLP Revenues in 2022/23 (MFR 7 2017/18 & 2018/19 GRA)	262
	2,484
Total Expenses Including Net Movement (Figure 7)	2,162
Revenue Requirment in 2022/23 (PUB/MH I-9U):	
Keeyask	502
MMTP	31
GNTL	97
	2,792
Net Income (Loss)	**(308)**
One-time Rate Increase Required to Breakeven	18%

As an alternative to a one-time 18% rate increase, based on the same revenues and costs as above, rate increases of approximately 5.5% annually would be required in order to achieve break even over a 3 year timeframe with net losses experienced in the first two years.

	Year 1	Year 2	Year 3
Domestic Revenue @ current rates (Figure 7)	1,700	1,700	1,700
Additional Revenue assuming 5.5% annual rate increases	*94*	*192*	*296*
Total Domestic Revenue	1,794	1,892	1,996
Extraprovincial & Other Revenue (Figure 7)	522	522	522
KHLP Revenues in 2022/23 (MFR 7 2017/18 & 2018/19 GRA)	262	262	262
	2,578	2,676	2,780
Total Expenses including Net Movement (Figure 7)	2,162	2,162	2,162
Revenue Requirement in 2022/23 (PUB/MH I-9U)			
Keeyask	502	502	502
MMTP	31	31	31
GNTL	97	97	97
	2,792	2,792	2,792
Net Income (Loss)	(215)	(116)	(12)

Since 2009, Manitoba Hydro's forecasts have projected indicative annual rate increases in the order of 3.5% or more. Exhibit 93, a scenario which was characterized in Order 59/18 as reflective of many of the PUB's decisions, contemplated 18 consecutive years of annual rate increases. In order to maintain the financial results as projected, those rate increases must be implemented each and every year. Otherwise, rate increases in subsequent years, necessarily must be higher to compensate for foregone or reduced rate increases.

The response to PUB/MH I-62b shows that the present value of additional revenues generated over a 17-year period of a 3.5% rate increase granted in 2019/20 is approximately $600 million (2019 dollars at a 6% nominal discount rate). If the PUB declines to approve the requested rate increase, Manitoba Hydro and its customers have approximately $600 million (2019 dollars) in incremental borrowing requirements. Alternatively, the PUB may grant a 3.5% in the following year, but in order to generate approximately the same amount of revenue, a rate increase nearer to 4% would be necessary in 2020/21. As a result, it is Manitoba Hydro's view that a 3.5% rate increase granted in 2019/20 is necessary in order to mitigate the impacts of Keeyask and the associated transmission and the need for even higher future rate increases.

PUB MFR 82 (Revised)
Export & Domestic Revenue

Incremental revenues and unit revenues from Keeyask by year, broken down by firm and opportunity sales.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

The following schedules have been prepared using simplifying assumptions with respect to the allocation of dependable energy that is used to serve firm sales, and consequently the revenue to attribute to Keeyask energy. There are many operational decisions made to manage reservoir levels and stream flow in order to maximize the overall value of energy generated by an integrated hydro-electric system. These decisions involve optimizing the collective generation output of the hydro-electric facilities on the system, thermal generation, and energy purchases. The output of individual facilities may appear to be sub-optimal in order to benefit the system as a whole. As a result, it is an arbitrary exercise to attribute the generation of an individual facility to serving any of Manitoba demand, the overall portfolio of firm sales or any one firm sale in an integrated hydro-electric system.

The first schedule calculates the total system average unit revenues (at generation) for domestic, firm export and non-firm export sales. The appropriate average unit revenue is applied to the Keeyask energy allocated for domestic, firm export and non-firm export energy to derive the revenue for each category.

For the purposes of this response, the Keeyask energy has been allocated between firm exports and opportunity exports under three sets of assumptions in order to provide an indicative range of revenue allocations as follows:

- Scenario 1: All of Keeyask energy assumed to be sold as opportunity sales.

- Scenario 2: Keeyask firm energy is assumed to serve the MP250 sale plus an amount of remaining firm contracts based proportionally on Keeyask firm energy to total system firm energy (approximately 10% declining gradually as Manitoba load grows).
- Scenario 3: All of Keeyask firm energy serves firm export sales.

In all three scenarios, Keeyask energy will not be used to serve domestic load until it is approximately needed for load growth. Scenarios 2 and 3 are shown below in **Figure 1** (Scenario 1 is commercially sensitive).

Total System Sales @ Generation

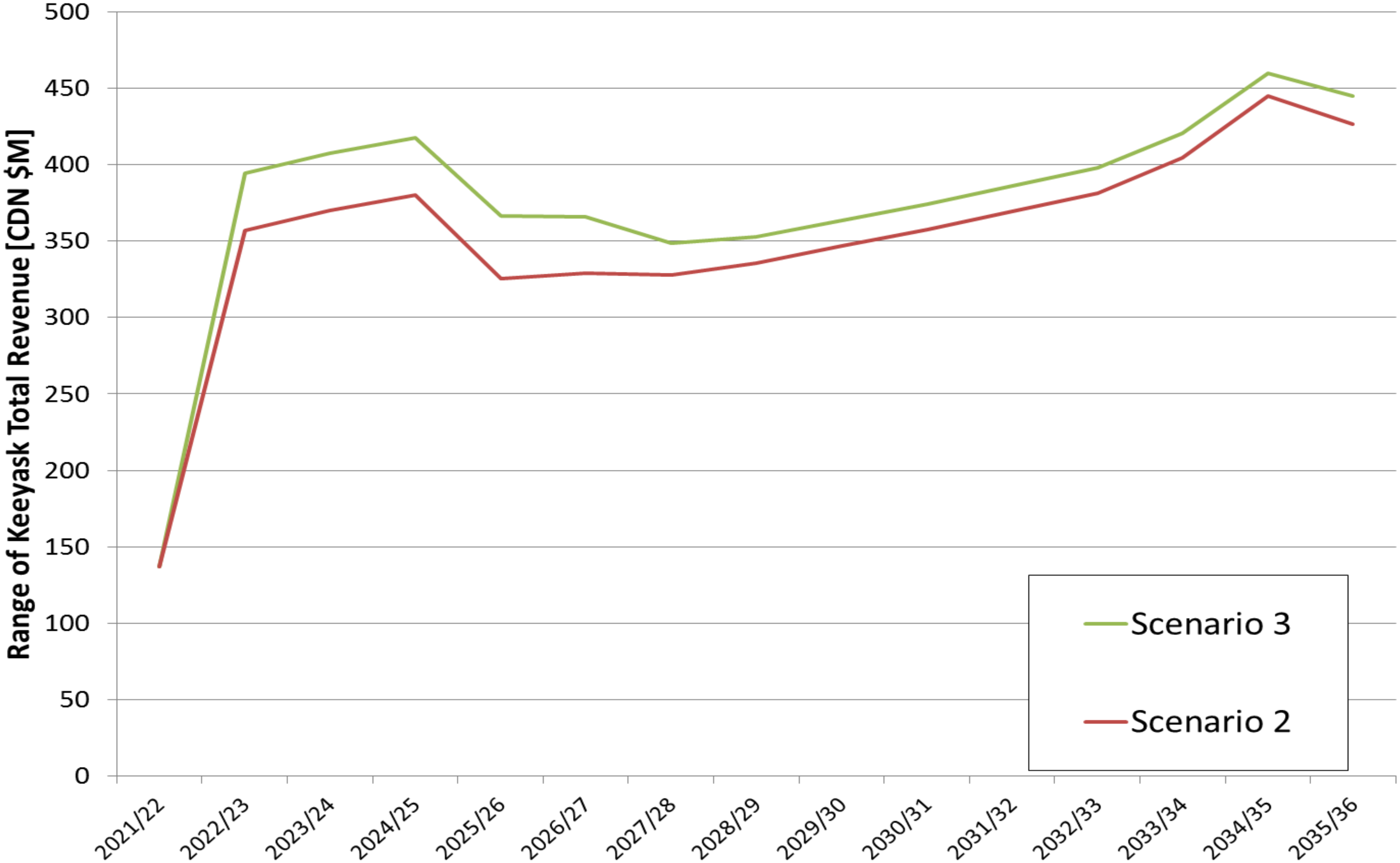
Fiscal	Domestic Revenue [CDN $M]	Domestic Energy [GWh]	Firm Export Revenue [CDN $M]	Non-Firm Export Revenue [CDN $M]	Total Export Revenue [CDN $M]	Firm Export Energy [GWh]	Non-Firm Export Energy [GWh]	Total Export Energy [GWh]	Domestic Average Unit Revenue [CDN $/MWh]	Firm Export Average Unit Revenue [CDN $/MWh]	Non-Firm Export Average Unit Revenue [CDN $/MWh]	Total Export Average Unit Revenue [CDN $/MWh]
2021/22	2 476.7	24 904	[redacted]	[redacted]	681.0	[redacted]	[redacted]	9 710	$ 99.45	[redacted]	[redacted]	$ 70.14
2022/23	2 536.1	25 001	[redacted]	[redacted]	779.2	[redacted]	[redacted]	11 964	$ 101.44	[redacted]	[redacted]	$ 65.13
2023/24	2 601.9	25 147	[redacted]	[redacted]	802.6	[redacted]	[redacted]	12 049	$ 103.47	[redacted]	[redacted]	$ 66.61
2024/25	2 666.8	25 268	[redacted]	[redacted]	823.8	[redacted]	[redacted]	11 937	$ 105.54	[redacted]	[redacted]	$ 69.01
2025/26	2 733.8	25 395	[redacted]	[redacted]	683.8	[redacted]	[redacted]	11 545	$ 107.65	[redacted]	[redacted]	$ 59.23
2026/27	2 804.6	25 542	[redacted]	[redacted]	691.3	[redacted]	[redacted]	11 392	$ 109.80	[redacted]	[redacted]	$ 60.68
2027/28	2 874.0	25 661	[redacted]	[redacted]	681.4	[redacted]	[redacted]	11 227	$ 112.00	[redacted]	[redacted]	$ 60.69
2028/29	2 947.6	25 802	[redacted]	[redacted]	693.6	[redacted]	[redacted]	11 085	$ 114.24	[redacted]	[redacted]	$ 62.57
2029/30	3 040.7	26 095	[redacted]	[redacted]	705.7	[redacted]	[redacted]	10 829	$ 116.52	[redacted]	[redacted]	$ 65.17
2030/31	3 138.0	26 402	[redacted]	[redacted]	715.3	[redacted]	[redacted]	10 563	$ 118.86	[redacted]	[redacted]	$ 67.71
2031/32	3 261.3	26 901	[redacted]	[redacted]	715.4	[redacted]	[redacted]	10 134	$ 121.23	[redacted]	[redacted]	$ 70.60
2032/33	3 394.2	27 449	[redacted]	[redacted]	712.3	[redacted]	[redacted]	9 688	$ 123.66	[redacted]	[redacted]	$ 73.52
2033/34	3 533.7	28 017	[redacted]	[redacted]	706.8	[redacted]	[redacted]	9 239	$ 126.13	[redacted]	[redacted]	$ 76.50
2034/35	3 679.4	28 599	[redacted]	[redacted]	698.4	[redacted]	[redacted]	8 784	$ 128.65	[redacted]	[redacted]	$ 79.51
2035/36	3 833.0	29 209	[redacted]	[redacted]	611.7	[redacted]	[redacted]	8 016	$ 131.23	[redacted]	[redacted]	$ 76.31

Scenario 1: Keeyask Sales @ Generation - All Non-Firm

Fiscal	Keeyask Firm Energy Domestic [GWh]	Keeyask Firm Energy Export [GWh]	Keeyask Non-Firm Energy Export [GWh]	Keeyask Total Energy [GWh]	Keeyask Firm Revenue Domestic [CDN $M]	Keeyask Firm Revenue Export [CDN $M]	Keeyask Non-Firm Revenue Export [CDN $M]	Keeyask Total Revenue [CDN $M]
2021/22	-	-	1 353	1 353	-	[redacted]	[redacted]	[redacted]
2022/23	-	-	4 351	4 351	-	[redacted]	[redacted]	[redacted]
2023/24	-	-	4 434	4 434	-	[redacted]	[redacted]	[redacted]
2024/25	-	-	4 433	4 433	-	[redacted]	[redacted]	[redacted]
2025/26	-	-	4 431	4 431	-	[redacted]	[redacted]	[redacted]
2026/27	-	-	4 430	4 430	-	[redacted]	[redacted]	[redacted]
2027/28	-	-	4 430	4 430	-	[redacted]	[redacted]	[redacted]
2028/29	-	-	4 429	4 429	-	[redacted]	[redacted]	[redacted]
2029/30	-	-	4 427	4 427	-	[redacted]	[redacted]	[redacted]
2030/31	-	-	4 426	4 426	-	[redacted]	[redacted]	[redacted]
2031/32	-	-	4 425	4 425	-	[redacted]	[redacted]	[redacted]
2032/33	-	-	4 425	4 425	-	[redacted]	[redacted]	[redacted]
2033/34	213	-	4 211	4 424	26.9	[redacted]	[redacted]	[redacted]
2034/35	796	-	3 627	4 423	102.4	[redacted]	[redacted]	[redacted]
2035/36	1 405	-	3 014	4 419	184.4	[redacted]	[redacted]	[redacted]

Fiscal	Keeyask Firm Energy Domestic [GWh]	Keeyask Firm Energy Export [GWh]	Keeyask Non-Firm Energy Export [GWh]	Keeyask Total Energy [GWh]	Keeyask Firm Revenue Domestic [CDN $M]	Keeyask Firm Revenue Export [CDN $M]	Keeyask Non-Firm Revenue Export [CDN $M]	Keeyask Total Revenue [CDN $M]
	Scenario 2: Keeyask Sales @ Generation - MP250 + ProRated contracts							
2021/22	-	[redacted]		1 353	-	[redacted]		137.0
2022/23	-			4 351	-			357.2
2023/24	-			4 434	-			369.7
2024/25	-			4 433	-			380.1
2025/26	-			4 431	-			325.3
2026/27	-			4 430	-			329.1
2027/28	-			4 430	-			327.9
2028/29	-			4 429	-			335.6
2029/30	-			4 427	-			346.6
2030/31	-			4 426	-			357.4
2031/32	-			4 425	-			369.3
2032/33	-			4 425	-			381.4
2033/34	213			4 424	26.9			404.2
2034/35	796			4 423	102.4			445.2
2035/36	1 405			4 419	184.4			426.4

Fiscal	Scenario 3: Keeyask Sales @ Generation - All Firm							
	Keeyask Firm Energy Domestic [GWh]	Keeyask Firm Energy Export [GWh]	Keeyask Non-Firm Energy Export [GWh]	Keeyask Total Energy [GWh]	Keeyask Firm Revenue Domestic [CDN $M]	Keeyask Firm Revenue Export [CDN $M]	Keeyask Non-Firm Revenue Export [CDN $M]	Keeyask Total Revenue [CDN $M]
2021/22	-	[redacted]	[redacted]	1 353	-	[redacted]	[redacted]	137.0
2022/23	-	[redacted]	[redacted]	4 351	-	[redacted]	[redacted]	394.2
2023/24	-	[redacted]	[redacted]	4 434	-	[redacted]	[redacted]	407.3
2024/25	-	[redacted]	[redacted]	4 433	-	[redacted]	[redacted]	417.7
2025/26	-	[redacted]	[redacted]	4 431	-	[redacted]	[redacted]	366.6
2026/27	-	[redacted]	[redacted]	4 430	-	[redacted]	[redacted]	366.0
2027/28	-	[redacted]	[redacted]	4 430	-	[redacted]	[redacted]	348.4
2028/29	-	[redacted]	[redacted]	4 429	-	[redacted]	[redacted]	352.8
2029/30	-	[redacted]	[redacted]	4 427	-	[redacted]	[redacted]	363.6
2030/31	-	[redacted]	[redacted]	4 426	-	[redacted]	[redacted]	374.4
2031/32	-	[redacted]	[redacted]	4 425	-	[redacted]	[redacted]	386.1
2032/33	-	[redacted]	[redacted]	4 425	-	[redacted]	[redacted]	398.0
2033/34	213	[redacted]	[redacted]	4 424	26.9	[redacted]	[redacted]	420.7
2034/35	796	[redacted]	[redacted]	4 423	102.4	[redacted]	[redacted]	459.6
2035/36	1 405	[redacted]	[redacted]	4 419	184.4	[redacted]	[redacted]	445.0


Range of Keeyask Total Revenue [CDN $M]
500
450
400
350
300
250
200
150
100
50
0
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
2035/36
Scenario 3
Scenario 2

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MMTP Project Description

Manitoba Hydro's capital expenditure forecast includes the construction of a new 500kV Transmission Line between Winnipeg and Duluth, Minnesota (MMTP).

The MMTP transmission line will originate at Dorsey Converter station located near Rosser, northwest of Winnipeg and extend 213 km south around Winnipeg to the Manitoba-Minnesota border, near Piney, Manitoba. The MMTP also includes associated upgrades at Dorsey, Riel and Glenboro stations.

The U.S. portion of the 500 kV line will initiate at the border and terminate at Iron Range Station near Grand Rapids, Minnesota. This project is known as the Great Northern Transmission Line (GNTL), and is being constructed by Minnesota Power.

MMTP Project Update

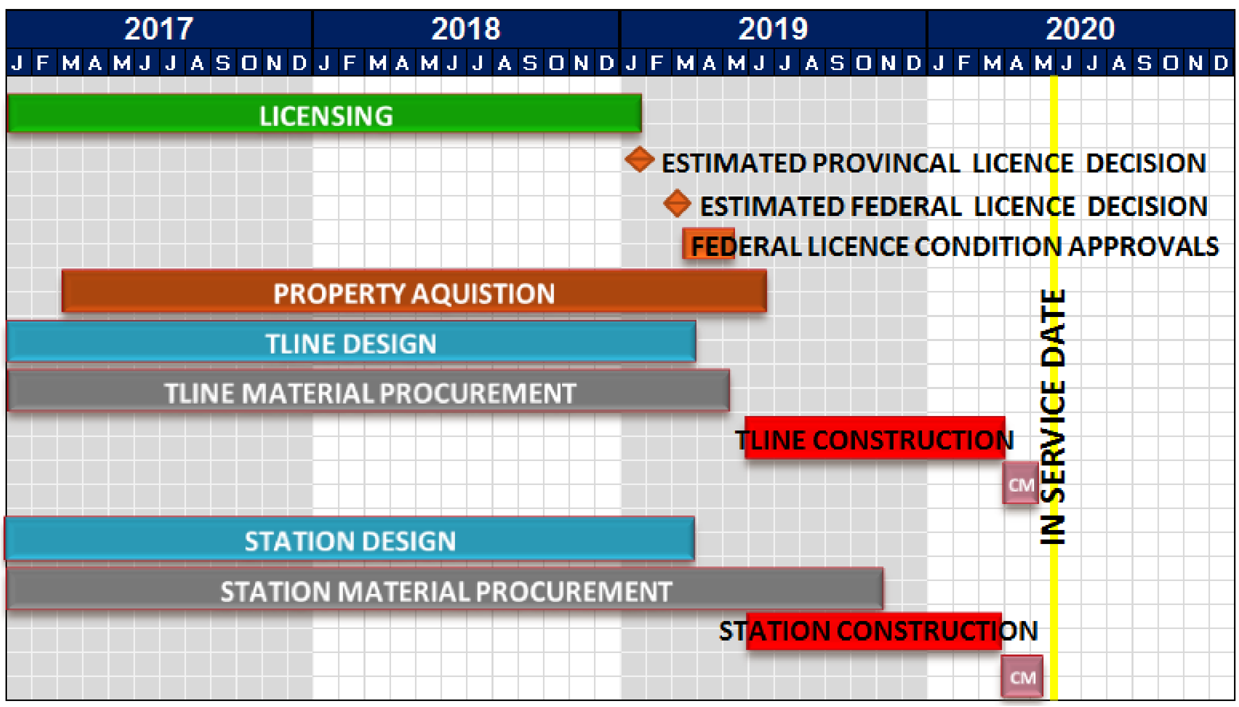
- Manitoba Hydro is awaiting a licensing decision by Manitoba Sustainable Development. Sagkeeng First Nation has put their request for judicial review of MMTP into abeyance until licensing decisions have been made.
- On November 15, 2018, the National Energy Board (NEB) released its Reasons for Decision report on MMTP determining "the Project is and will be required by the present and future public convenience and necessity" and recommending the Governor in Council (GIC) issue a certificate for the Project. There were 28 recommended conditions attached to the decision.
- Manitoba Hydro now awaits a decision on the approval of the issuance of a certificate by the GIC.
- Property acquisition is continuing and over 80% of the private land owners along the proposed transmission line route between Vivian, Manitoba and the U.S. Border have signed easement agreements.
- In order to secure the project in-service date Manitoba Hydro must move forward with long lead time items such as the material contracts prior to receiving Provincial and Federal regulatory approvals. Failure to do so would result in substantial project delays. Should Manitoba Hydro receive notification that the project will not receive its necessary regulatory approvals, materials may be re-used on future transmission projects in order to recover sunk costs.
- Tower steel began to arrive at the material storage yard in November and will continue to be delivered into January 2019.
- Regulatory approvals were not received in time to start construction in December 2018 as anticipated, therefore contractors who submitted proposals for the construction contracts were asked to update their pricing and plans for a later construction start date of June 2019. Contractors were asked to submit this information by December 19, 2018. Construction Contracts will not be awarded until receipt of regulatory approvals.
- The control budget will be reviewed later this year once regulatory approvals and conditions have been received, and construction start established.

MMTP Budget

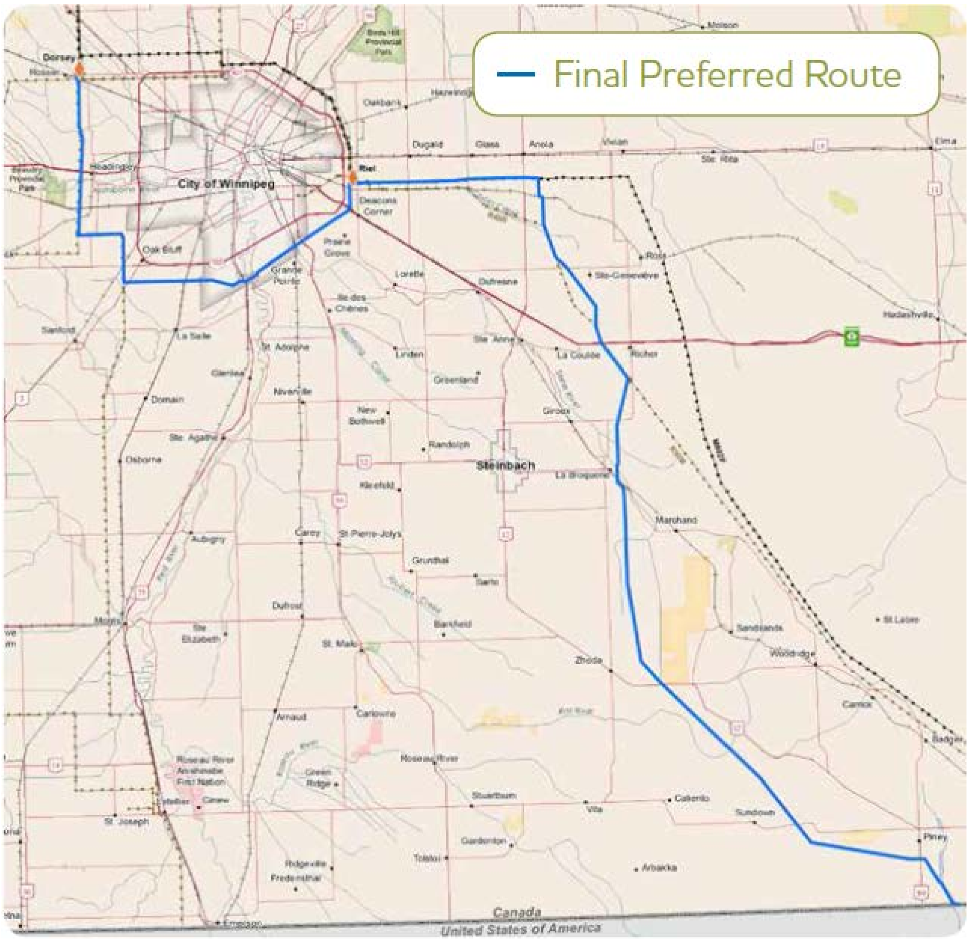
MMTP Budget Summary (in Millions $)			
Item #	**Item**	**Total Project Control Budget**	**Actual costs to Dec 31, 2018**
1.1	Licensing & Environmental	31.5	22.8
1.2	500 kV Transmission Line *	213.6	61.3
1.3	Station Upgrades*	112.8	24.6
1.4	Contingency	95.3	-
1.5	Total	453.2	108.7

*No construction contracts above $50 million are currently in place.

MMTP Project Schedule



MMTP Project Route



11

REFERENCE:

2017/18 GRA PUB/MH II-88; Compliance Filing to Order 59/18 pg. 2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide an update of PUB/MH II-88(b) with: June 1, 2018 consumer rates, updated Bipole III revenue requirement, and deducting net export revenues from the class costs (as opposed to adding net export revenues to class revenues). Provide the charts with rate differentiation to move the Revenue to Cost Coverage ratios of all classes within the zone of reasonableness in 1, 5, and 9 years. Present versions with and without the requested 3.5% rate increase and show the indicated rate increases to two decimal places. Identify any limitations or concerns with the resulting RCCs and rate differentiation.

RESPONSE:

Manitoba Hydro modified the methodology used in PCOSS18, in order to reflect the directives arising from Order 59/18 identified as in scope in Order 1/19 as follows:

- The alternate Revenue to Cost Coverage ("RCC") ratio methodology was used (Directives 5 & 27). In the alternate RCC calculation Net Export Revenue is treated as a reduction of class cost, rather than as an addition to class revenue.
- Non tariffable transmission was excluded from the allocation of Net Export Revenue (Directive 24). This resulted in an increase of $2.6 million in net Transmission costs, with an offsetting $2.6 million reduction in net Generation costs.
- A new subfunction was added to allocate the specified customer service costs to all classes other than GSL 30-100kV and GSL >100kV (Directive 25). The revised allocation results in a decrease in net costs of $0.6 million for GSL 30-100kV and $1.5 million for GSL >100kV.

Figure 1 provides the RCC impacts of each change, as well as the revised PCOSS18 results incorporating all methodology changes.

Figure 1

	PCOSS18	Directives 5 & 27	Directive 24	Directive 25	PCOSS18 59/18
Residential	94.8%	-1.3%	0.0%	-0.1%	93.4%
GSS ND	112.5%	3.2%	0.0%	-0.2%	115.5%
GSS D	101.0%	0.3%	0.0%	-0.2%	101.1%
GSM	98.3%	-0.5%	0.0%	-0.1%	97.7%
GSL 0-30	99.1%	-0.4%	0.1%	-0.2%	98.6%
GSL 30-100	109.3%	3.7%	0.1%	1.1%	114.2%
GSL >100	108.6%	3.7%	0.1%	1.0%	113.4%
Area & Roadway Lighting	100.3%	0.0%	0.0%	-0.2%	100.1%

To provide a high level indication of the anticipated shift in functionalized costs and revenue cost coverage ratios in 2019/20 with Bipole III in-service, the following assumptions have been made:

- Bipole III costs based on revised capital cost of $4.77 billion.
- The estimated $334 million carrying and operating costs of Bipole III has been functionalized as Generation. These costs exclude the costs of the Riel 230/500 kV AC station that were already included in PCOSS18 Transmission costs.
- The residual increase in revenue requirement, which was not specifically attributed to Bipole III, is assumed related to existing assets and has been functionalized by cost category in proportion to the PCOSS18 revenue requirement.
- The $78 million funding provided by amortization of the Bipole III Reserve Account has been distributed proportionally based on class revenues, consistent with PUB findings on page 190 of Order 59/18.
- Since PCOSS18 reflects domestic revenues based on August 1, 2016 rates, class revenues were first revised to include the June 1, 2018 differentiated rate increases and then adjusted on an across-the-board basis in order to offset the remaining increase in forecast revenue.

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

The tables below provides the annual rate differentiation required to move all classes into the zone of reasonableness (95-105%), while maintaining overall revenue neutrality, over 1, 5 and 9 years. The revenue shortfall that results from the below average rate changes for the GSS ND and A&RL classes is assumed to be recovered from all classes below unity, and is distributed between the Residential, First Nations On-Reserve, GSM and GSL 0-30 kV classes such that the final RCC for all four is equivalent.

The initial class revenue cost coverage ratios in Figure 2 reflect the previously discussed methodology changes, as well as the Bipole III related adjustments to revenue requirement.

Figure 2: At June 1, 2018 Rates

	Initial RCC including BPIII	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 9 Years	Final RCC
Residential	96.5%	1.85%	0.37%	0.20%	98.3%
First Nations On-Reserve	93.1%	5.61%	1.10%	0.61%	98.3%
GSS ND	116.7%	-10.02%	-2.09%	-1.17%	105.0%
GSS D	101.8%	0.00%	0.00%	0.00%	101.8%
GSM	97.5%	0.85%	0.17%	0.09%	98.3%
GSL 0-30	96.1%	2.27%	0.45%	0.25%	98.3%
GSL 30-100	104.6%	0.00%	0.00%	0.00%	104.6%
GSL >100	101.9%	0.00%	0.00%	0.00%	101.9%
Area & Roadway Lighting	118.7%	-11.56%	-2.43%	-1.36%	105.0%

The initial class revenue cost coverage ratios in Figure 3 are based on revenues that incorporate the 3.5% rate increase requested in the current application on an across-the-board basis, in addition to the previously noted methodology and revenue requirement changes.

Figure 3: Including Requested 3.5% Rate Increase

	Initial RCC including BPIII and Requested 3.5%	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 9 Years	Final RCC
Residential	96.5%	1.83%	0.36%	0.20%	98.3%
First Nations On-Reserve	93.1%	5.60%	1.09%	0.61%	98.3%
GSS ND	116.7%	-10.06%	-2.10%	-1.17%	105.0%
GSS D	101.8%	0.00%	0.00%	0.00%	101.8%
GSM	97.4%	0.93%	0.18%	0.10%	98.3%
GSL 0-30	96.1%	2.32%	0.46%	0.26%	98.3%
GSL 30-100	104.6%	0.00%	0.00%	0.00%	104.6%
GSL >100	101.9%	0.00%	0.00%	0.00%	101.9%
Area & Roadway Lighting	119.1%	-11.81%	-2.48%	-1.39%	105.0%

The RCCs shown for the First Nations On-Reserve class are high level estimates that are intended to reflect the RCC impact of the June 1, 2018 rate freeze. Manitoba Hydro has not been able to modify PCOSS18 to fully incorporate the new First Nations On-Reserve class due to the absence of class specific load research and customer weighting factors. In absence of updated costs profiles the new class has been attributed 7% of total Residential costs, which is consistent with the class's share of total Residential class revenues prior to the rate freeze. The approach likely overstates the RCC of the First Nations On-Reserve class, as the class consists largely of electric heating customers that have a higher cost-to-serve than standard customers. The approach will also somewhat understate the RCC for the revised Residential class, which now contains relatively fewer electric heating customers.

REFERENCE:

2017/18 GRA PUB/MH II-88; Compliance Filing to Order 59/18 pg. 2

PREAMBLE TO IR (IF ANY):

QUESTION:

b) In order to move the General Service Small – Non-Demand class RCC towards the zone of reasonableness as directed in Order 59/18 Directive 5, Manitoba Hydro adjusted the energy, demand, and basic charge components of the rates in order to maintain commonality with the General Service Small – Demand and General Service Medium rates.

Provide indicative energy, demand, and basic charge rates reflecting the assumed "end goal" of having the GSS-ND class RCC within the zone of reasonableness. In preparing this response, use the update of PUB/MH II-88 provided in the response to (a) of this information request. Does Manitoba Hydro have any concerns with the resulting energy, demand, or basic charge rates?

In Manitoba Hydro's view, will it be feasible to maintain harmonized rates among the GSS and GSM classes? If not, identify potential courses of action to achieve the goal of having all classes' RCCs within the zone of reasonableness.

RESPONSE:

Achieving the targeted revenue requirement for the Small Non-Demand, Small Demand and Medium Demand customer classes requires a delicate balancing act when setting blocked energy rates for these customers. The three groups represent very diverse load characteristics, as indicated by the percentage of kW.h consumed in each block shown in the table below.

	General Service Small Non-Demand	General Service Small Demand	General Service Medium
First 11,000 kW.h	91%	43%	9%
Next 8,500 kW.h	9%	23%	7%
Balance		35%	85%

Amounts may not add due to rounding

As this table indicates, increasing or decreasing the first block energy rate will have a significant impact on the revenue received from Small Non-Demand customers, but will have considerably less impact on Small Demand and Medium Demand customers. Conversely, increasing the tail block rate would have no impact on Small Non-Demand customers but will greatly impact the Small Demand and Medium Demand customers.

Two other important considerations when determining the blocked energy rates for these customers is the role the Basic Charge and Demand Charge play on each subclass. The majority of customers are Small Non-Demand, hence increasing the Basic Charge, even minimally, will generate more revenue from this group of customers than the other two groups. With respect to Demand Charges, Small Non-Demand customers do not pay a Demand Charge; therefore the first block energy rate is higher to compensate for this. Medium customers, on the other hand, generate roughly 34% of their total revenue from demand charges, much higher than the 18% demand revenue received from Small Demand customers. The tail block energy rate is therefore lower to account for this.

The substantial differences in RCC between GSS ND (116.7), GSS Demand (101.8) and GSM (97.5) as shown in Figure 2 in the response to PUB/MH I – 61a poses a significant challenge in accomplishing the goal of moving the GSS ND class into the ZOR under a harmonized rate structure. While dramatic changes to the rate components could provide a means of attaining the overall desired revenue in order to have RCCs fall within the ZOR (such as elimination of the basic monthly charge and substantial increase to the 2nd block energy rate), the resulting rates would not yield price signals that are aligned with cost causation and the outputs of the Cost of Service study. As an example, based on cost causation it could be argued that the current basic monthly charge, which reflects the fact that significant customer-related costs are incurred in providing GSS and GSM customers with access to the Manitoba Hydro system regardless of the level of energy consumed for each customer, should be increased for all three customer classes, as opposed to eliminated.

In Manitoba Hydro's view it is not appropriate to propose the magnitude of rate rebalancing required to achieve the RCC goals in advance of a more thorough analysis of class cost characteristics, load profiles and bill frequencies that would allow Manitoba Hydro to evaluate other rate design options.

REFERENCE:

Application pg. 33

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Indicate the actual foregone revenue from the First Nations On Reserve Residential and Diesel Residential customer classes for the 2018/19 fiscal year compared to the revenue that would have been received if the customer class and 0% rate increase had not been implemented.
b) Indicate the foregone revenue for the First Nations On-Reserve Residential and Diesel Residential customer classes for the 2019/20 test year resulting from the June 1, 2018 0% rate increase.
c) Indicate the foregone revenue for the First Nations On-Reserve Residential and Diesel Residential customer classes for the test year if this customer class does not receive a rate increase in the test year. Indicate the foregone revenue due to the June 1, 2018 0% rate increase as well as the foregone revenue due to an April 1, 2019 0% rate increase.
d) What is the rate impact to the other customer classes to keep Manitoba Hydro revenue neutral for each of items (a), (b), and (c).
e) What is the bill impact to the Residential Basic customer class to keep Manitoba Hydro revenue neutral for each of items (a), (b), and (c).

RESPONSE:

a) The actual foregone revenue from the First Nations on Reserve Residential and Diesel Residential customer classes for the 2018/19 fiscal year on account of receiving a 0% rate increase effective June 1, 2018 is as follows:

2018/19 YTD Actual (Jun-Nov 2018)	$588,000
Forecast (Dec 2018 - Mar 2019)	$846,000
Total	$1,434,000

b) The foregone revenue from the First Nations on Reserve Residential and Diesel Residential customer classes for the 2019/20 fiscal year resulting from a 0% rate increase effective June 1, 2018 is estimated to be $1.9 million.

c) An additional $1.7 million in revenue would be foregone if there is a 0% increase for First Nations Residential on Reserve and Diesel Residential customer classes in 2019/20. The cumulative effect of a 0% rate increase on June 1, 2018 as well as a 0% rate increase on April 1, 2019 is foregone revenue of approximately $3.6 million.

d) To maintain revenue neutrality on account of the 0% increase on June 1, 2018 to First Nations on Reserve Residential and Diesel Residential customer classes, all other customer classes received an additional 0.13% increase in the 2018/19 fiscal year. If there is no rate increase for First Nations on Reserve Residential and Diesel Residential customer classes in fiscal 2019/20, all other classes would need an additional 0.10% increase. The cumulative rate impact to maintain revenue neutrality as a result of no rate increase to the First Nation on Reserve Residential and Diesel Residential customer classes in 2018/19 and 2019/20 is an additional 0.22% increase to the other customer classes.

e) The bill impacts to the Residential Basic customer class to maintain revenue neutrality are as follows:

a) To maintain revenue neutrality arising from the 0% increase granted in 2018/19 to the First Nations On-Reserve Residential customer class ("FNOR"), the Residential impact in 2018/19 is as follows:

kWh	June 1, 2018 Bill if FNOR not implemented on June 1, 2018 $ / Month	June Approved Residential Bill $ / Month	Difference in $ / Month	Percent Change
250	$29.69	$29.73	$0.04	0.13%
750	$72.27	$72.36	$0.09	0.12%
1 000	$93.56	$93.68	$0.12	0.13%
2 000	$178.73	$178.95	$0.22	0.13%
5 000	$434.22	$434.76	$0.54	0.13%

b) To maintain revenue neutrality arising from the 0% increase granted in 2018/19 to the First Nations On-Reserve Residential customer class ("FNOR"), the Residential impact in 2019/20 is as follows:

kWh	April 1, 2019 Bill if FNOR not implemented in June 1, 2018 $ / Month	April 11, 2019 Proposed Residential Bill $ / Month	Difference in $ / Month	Percent Change
250	$30.74	$30.78	$0.04	0.13%
750	$74.82	$74.91	$0.10	0.13%
1 000	$96.85	$96.98	$0.13	0.13%
2 000	$185.01	$185.25	$0.24	0.13%
5 000	$449.48	$450.06	$0.58	0.13%

c) 1) To maintain revenue neutrality if no increase for First Nations On-Reserve Residential class (“FNOR”) in 2019/20, the Residential impact in 2019/20 is as follows:

kWh	April 1, 2019 Proposed Residential Bill $ / Month	April 1, 2019 Residential Bill if no increase to FNOR and Diesel Residential in 18/19 & 19/20 $ / Month	Difference in $ / Month	Percent Change
250	$30.78	$30.81	$0.03	0.10%
750	$74.91	$74.98	$0.07	0.10%
1 000	$96.98	$97.07	$0.09	0.10%
2 000	$185.25	$185.43	$0.18	0.10%
5 000	$450.06	$450.49	$0.43	0.10%

c) 2) Total Residential impact arising from a 0% rate increase in 2018/19 and a 0% rate increase in 2019/20 to the First Nations On-Reserve Residential and Diesel Residential customer classes (“FNOR”) is as follows:

kWh	April 1, 2019 Bill if FNOR not implemented on June 1, 2018 $ / Month	April 1, 2019 Residential Bill if no increase to FNOR and Diesel Residential in 18/19 & 19/20 $ / Month	Difference in $ / Month	Percent Change
250	$30.74	$30.81	$0.07	0.23%
750	$74.82	$74.98	$0.17	0.23%
1 000	$96.85	$97.07	$0.22	0.23%
2 000	$185.01	$185.43	$0.42	0.23%
5 000	$449.48	$450.49	$1.02	0.23%

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

For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
OPERATING ACTIVITIES			
Net Income	10	92	110
Add Back:			
Depreciation and Amortization	402	465	505
Net Finance Expense	578	712	741
Net Movement Impacts on Depreciation and Finance Expense	3	21	23
Adjustments for Non-Cash Items	(12)	17	(3)
Adjustments for Non-Cash Working Capital Accounts	(256)	(32)	(34)
Interest Paid	(880)	(964)	(1 028)
Interest Received	23	14	16
Cash Provided by Operating Activities	(132)	326	331
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt	3 441	3 852	2 150
Retirement of Long-Term Debt	(583)	(1 775)	(227)
Repayments from/(Advances to) External Entities	(57)	(52)	(45)
Proceeds from Partnership Issuances	44	51	44
Sinking Fund Withdrawals	165	193	130
Sinking Fund Payment	(165)	(193)	(214)
Other	(11)	-	-
Cash Provided by Financing Activities	2 833	2 076	1 838
INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2 610)	(1 933)	(1 735)
Additions to Intangible Assets	(133)	(219)	(207)
Additions to Regulatory Deferral Balances	(93)	(93)	(94)
Contributions Received	194	62	13
Cash Paid to the City of Winnipeg	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(104)	(69)
Other	(3)	(1)	(0)
Cash Used for Investing Activities	(2 706)	(2 303)	(2 110)
Net Increase (Decrease) in Cash	(4)	98	59
Cash at Beginning of Year	634	579	678
Cash at End of Year	629	678	737

Manitoba Hydro

Manitoba Hydro 2019/20 Electric Rate Application
PUB/MH I-4a-d (Updated)

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

For the year ended March 31	ACTUAL 2018	CURRENT OUTLOOK 2019	APPROVED BUDGET 2020
OPERATING ACTIVITIES			
Cash Receipts from Customers	1 883	2 111	2 187
Cash Paid to Suppliers and Employees	(1 158)	(836)	(843)
Interest Paid	(538)	(690)	(717)
Interest Received	23	14	16
Cash Provided by Operating Activities	211	600	642
FINANCING ACTIVITIES			
Proceeds from Long-Term Debt*	3 441	3 852	2 150
Retirement of Long-Term Debt	(583)	(1 775)	(227)
Repayments from/(Advances to) External Entities	(57)	(52)	(45)
Proceeds from Partnership Issuances	44	51	44
Sinking Fund Withdrawals	165	193	130
Sinking Fund Payment	(165)	(193)	(214)
Other	(11)	0	0
Cash Provided by Financing Activities	2 833	2 076	1 838
INVESTING ACTIVITIES			
Additions to Capital Assets	(2 949)	(2 193)	(2 021)
Additions to Intangible Assets	(135)	(231)	(231)
Additions to Regulatory Deferral Balances	(93)	(94)	(96)
Contributions Received	194	62	13
Cash Paid to the City	(16)	(16)	(16)
Cash Paid for Mitigation and Major Development Liabilities	(46)	(104)	(69)
Other	(3)	(1)	(0)
Cash Used for Investing Activities	(3 048)	(2 578)	(2 421)
Net Increase (Decrease) in Cash	(4)	98	59
Cash at Beginning of Year	634	579	678
Cash at End of Year	629	678	737

* 2018 Actuals include $3.4 billion related to proceeds from Long-Term Debt and $0.05 billion net proceeds from short-term borrowings (Notes Payable).

b) No update is required to this response as a result of the updates provided in the Supplement to the 2019/20 Electric Rate Application.

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REFERENCE:

PUB/MH I-36

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the most current Debt Management Strategy document (after review by MHEB).

RESPONSE:

Manitoba Hydro's last Debt Management Strategy was approved in April 2017 and filed as Appendix 3.5 in the 2017/18 & 2018/19 General Rate Application. A comprehensive review of Manitoba Hydro's operations, forecasts and financial plans, including examination of financial targets is currently being undertaken to allow the MHEB to establish a long-term financial plan for the Corporation. As Manitoba Hydro is in the process of working towards a long range plan, there is no long term Integrated Financial Forecast ("IFF") upon which to base Manitoba Hydro's Debt Management Strategy ("DMS"). Once a new long term plan and IFF have been established by the MHEB, Manitoba Hydro will prepare a DMS which will be reflective of the long term direction for the Corporation.

Manitoba Hydro will continue to manage its debt as a function of its current corporate circumstances, net income levels, financial metrics and targets, outlook and the prevailing interest rate environment including the shape of yield curve. As noted in the response to PUB/MH I-40, Manitoba Hydro will continue to mitigate refinancing risk by maintaining the weighted average term to maturity ("WATM") on new debt issuance at approximately 20 years due to the diminished potential savings and increased risk of targeting a 12 year WATM for new debt issuance.

Due to high levels of new borrowings for prospective cash requirements, in order to manage the overall interest rate risk profile, Manitoba Hydro has continued to keep the percentage of aggregated floating rate debt and short term debt below 10% of the total debt portfolio.

Additionally as noted in the response to PUB/MH I-39, Manitoba Hydro will continue to monitor markets and upcoming cash requirements to determine the appropriate level of unencumbered cash required to protect against liquidity risk and adjust the balance accordingly.

REFERENCE:

2017/18 GRA MH68 pg. 64

PREAMBLE TO IR (IF ANY):

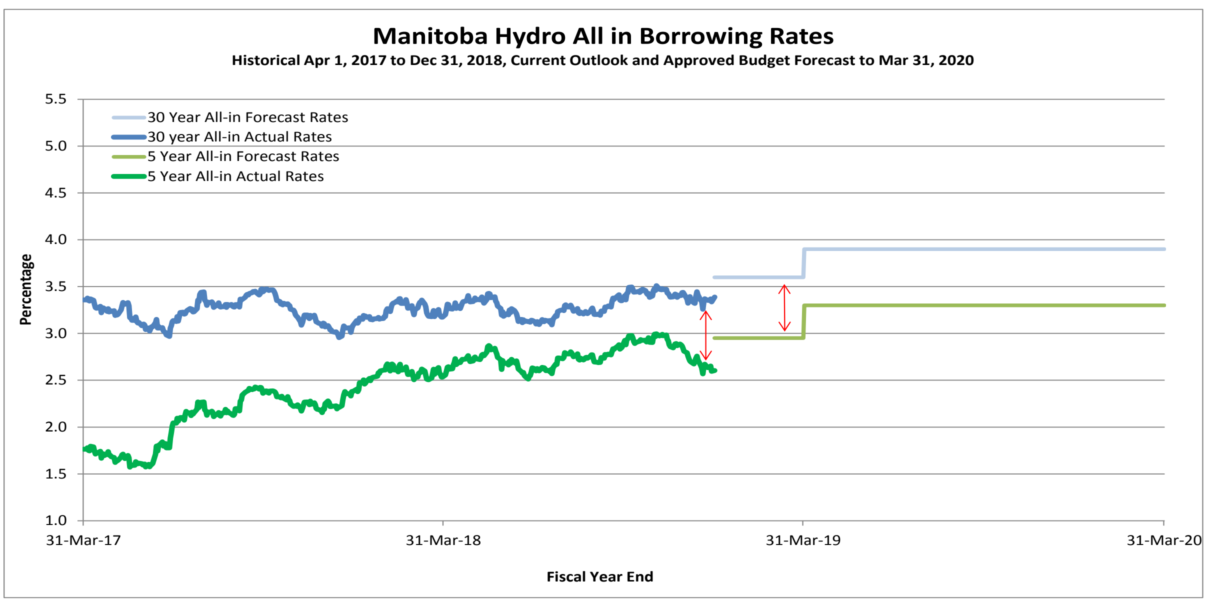
QUESTION:

a) File an update to the chart presented in MH68 slide 64 and related table of data points detailing the yields between the five year and 30 year Government of Canada bond rate. Please provide the chart through to the end of the test year.

b) Indicate the level of savings currently available for shorter term interest rates on 2018/19 and 2019/20 debt issuances.

RESPONSE:

a) The following chart is an update to the chart presented in Exhibit MH-68, slide 64, which showed the differential between the 5 and 30 year Province of Manitoba borrowing costs and is based on the Winter 2018 interest rate forecast.



The following data points detail the Government of Canada yields, the Province of Manitoba credit spreads and the Province of Manitoba all-in borrowing costs from March 31, 2017 to the end of the test year. Actual data for April 1, 2017 to December 31, 2018 is based on the monthly average of the daily series.

(All Rates in %)	Government of Canada			Province of MB Spreads			Province of MB All-in Cost		
	30 year	5 year	Difference	30 year	5 year	Difference	30 year	5 year	Difference
April 2017	2.23	1.07	1.16	1.06	0.66	0.40	3.29	1.73	1.56
May 2017	2.16	1.01	1.15	1.03	0.63	0.41	3.20	1.64	1.56
June 2017	2.05	1.13	0.92	1.01	0.63	0.38	3.06	1.76	1.30
July 2017	2.28	1.55	0.73	0.98	0.60	0.38	3.26	2.15	1.11
August 2017	2.33	1.54	0.78	0.98	0.60	0.38	3.31	2.15	1.16
September 2017	2.42	1.75	0.67	0.99	0.61	0.38	3.40	2.36	1.05
October 2017	2.42	1.74	0.68	0.94	0.59	0.35	3.36	2.33	1.04
November 2017	2.27	1.66	0.61	0.88	0.56	0.32	3.15	2.22	0.93
December 2017	2.20	1.76	0.44	0.84	0.52	0.31	3.04	2.28	0.76
January 2018	2.36	2.02	0.34	0.80	0.49	0.31	3.16	2.51	0.65
February 2018	2.46	2.11	0.35	0.85	0.51	0.34	3.31	2.62	0.69
March 2018	2.34	2.03	0.31	0.90	0.53	0.37	3.24	2.56	0.68
April 2018	2.37	2.11	0.26	0.93	0.57	0.36	3.31	2.68	0.62
May 2018	2.42	2.23	0.19	0.92	0.54	0.38	3.34	2.77	0.58
June 2018	2.27	2.09	0.18	0.91	0.54	0.37	3.17	2.62	0.55
July 2018	2.23	2.12	0.12	0.93	0.53	0.39	3.16	2.65	0.51
August 2018	2.32	2.23	0.08	0.93	0.52	0.41	3.25	2.76	0.49
September 2018	2.36	2.26	0.10	0.94	0.52	0.42	3.30	2.78	0.52
October 2018	2.51	2.42	0.10	0.93	0.51	0.41	3.44	2.93	0.51
November 2018	2.47	2.36	0.11	0.97	0.56	0.41	3.44	2.91	0.52
December 2018	2.22	2.00	0.22	1.14	0.68	0.46	3.36	2.68	0.68
January 2019 to March 2019	2.50	2.30	0.20	1.10	0.65	0.45	3.60	2.95	0.65
April 2019 to March 2020	2.90	2.70	0.20	1.00	0.60	0.40	3.90	3.30	0.60

b) In the response to PUB/MH I-40a-b based on the original application, the potential savings were calculated based on forecast debt issuance for the entirety of fiscal 2019 and 2020. Similarly, if Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances and existing debt issued in the Current Outlook year rather than a 20 year average, the level of savings available using the forecast rates incorporated in the 2018/19 Current Outlook and 2019/20 Approved Budget would be approximately $3 million in fiscal 2019 and $8 million in fiscal 2020 on a cumulative basis. The yield curve has flattened considerably since the Winter 2017 interest rate forecast was prepared, and as a result the potential savings have diminished.

If Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances beginning in January 2019 rather than a 20 year average, the level of savings available using the forecast rates incorporated in 2018/19 Current Outlook and 2019/20 Approved Budget, would be approximately $1 million in fiscal 2019 and $4 million in fiscal 2020 on a cumulative basis.

The flattening yield curve limits the potential savings available for long term debt with shorter terms to maturity. In addition, the availability of future surplus cash to retire maturing debt is uncertain as Manitoba Hydro reviews its longer term financial plan. Without a longer term forecast of cash flow, issuing more debt with shorter terms to maturity could significantly increase the relative level of refinancing risk. Given the diminished potential savings and the cash flow uncertainty, the Corporation views it imprudent at this time to reduce the target weighted average term to maturity of new debt issuance for the sole purpose of short term interest savings and will continue to favour debt with longer terms to maturity for new debt issuances.

REFERENCE:

Current Application p.22, Additional Information Attachment 5, PUB I-34 b) & c), PUB I-40 b)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide an expanded version of Figure 2.7 (Application, page 22) that includes the years 2017/18 through 2019/20 and that also includes the following:
   i. Canada and MH 5 Year Bond Rates
   ii. Canada and MH 10 Year Bond Rates
   iii. Canada and MH 30 Year Bond Rates
   iv. MH 12 Year WATM (also include for Current Application)
   v. MH 20 Year WATM

b) Please provide a revised version of the response to part (a) which, for the years 2018/19 and 2019/20, also includes the values from the updated interest rate forecast provided in response to PUB I-34 b) & c).

c) Please provide a revised response to PUB I-40 b) based on the updated interest rate forecast provided in the response to PUB I-34 b) & c).

d) Based on the various interest rate forecasts provided in the response to PUB I-34 b), what are the highest and lowest 2019/20 values for each of the following:
   i. Canada and MH 5 Year Bond Rates
   ii. Canada and MH 10 Year Bond Rates
   iii. Canada and MH 30 Year Bond Rates
   iv. MH 12 Year WATM
   v. MH 20 Year WATM

RATIONALE FOR QUESTION:

To understand the changes in the interest rate forecasts since the last GRA.

RESPONSE:

a) The following table provides an expanded version of Figure 2.7 for the forecasts underpinning the Application and Exhibit 93 as well as the Winter 2018 forecast provided in PUB I-34 b) and c).

	Application Winter 2017			Exhibit 93 Spring 2017			Winter 2018	
	2017/18	2018/19	2019/20	2017/18	2018/19	2019/20	2018/19	2019/20
MH Short Term Interest Rate	1.05%	1.50%	2.20%	0.55%	0.90%	1.55%	1.55%	2.20%
MH Long Term Interest Rate								
12 Year WATM	2.65%	3.15%	3.65%	2.55%	3.05%	3.45%	3.20%	3.55%
20 Year WATM	3.00%	3.50%	4.00%	3.15%	3.55%	3.90%	3.45%	3.80%
Canada 5 Year Bond Rate	1.85%	2.20%	2.70%	1.35%	1.90%	2.35%	2.30%	2.70%
MH 5 Year Bond Rate	2.30%	2.75%	3.30%	1.95%	2.45%	2.95%	2.95%	3.30%
Canada 10 Year Bond Rate	2.10%	2.45%	2.90%	1.95%	2.45%	2.80%	2.35%	2.80%
MH 10 Year Bond Rate	2.80%	3.25%	3.80%	2.80%	3.30%	3.70%	3.30%	3.70%
Canada 30 year Bond Rate	2.40%	2.80%	3.20%	2.50%	2.85%	3.20%	2.50%	2.90%
MH 30 Year Bond Rate	3.20%	3.70%	4.20%	3.55%	3.85%	4.15%	3.60%	3.90%
U.S. – Cdn Exchange Rate	1.27	1.27	1.26	1.35	1.32	1.29	1.31	1.30

* Not including the 1% Provincial Guarantee Fee

** The 2018/19 rates for the Winter 2018 forecast provided in PUB/MH I-34c are calculated with actual rates to December 2018 and forecasted rates thereafter.

b) Please see the response to part a).

c) In PUB/MH I-40a-b based on the original application, the potential savings were calculated based on forecast debt issuance for the entirety of fiscal 2019 and 2020. Similarly, if Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances and existing debt issued in the Current Outlook year rather than a 20 year average, the level of savings available using the forecast rates incorporated in 2018/19 Current Outlook and 2019/20 Approved Budget, would be approximately $3 million in fiscal 2019 and $8 million in fiscal 2020 on a cumulative basis. The yield curve has flattened considerably since the Winter 2017 interest rate forecast was prepared, and as a result the potential savings have diminished.

If Manitoba Hydro were to target a 12 year weighted average term to maturity for new debt issuances beginning in January 2019 rather than a 20 year average, the level of savings available using the forecast rates incorporated in 2018/19 Current Outlook and 2019/20 Approved Budget, would be approximately $1 million in fiscal 2019 and $4 million in fiscal 2020 on a cumulative basis.

d) The following table shows the highest and lowest 2019/20 fiscal year values from the Spring 2017, Winter 2017, and Winter 2018 forecasts:

	Highest	Lowest
Canada 5 Year Bond Rate	2.70% Winter 2017 & Winter 2018	2.35% Spring 2017
MH 5 Year Bond Rate	3.30% Winter 2017 & Winter 2018	2.95% Spring 2017
Canada 10 Year Bond Rate	2.90% Winter 2017	2.80% Spring 2017 & Winter 2018
MH 10 Year Bond Rate	3.80% Winter 2017	3.70% Spring 2017 & Winter 2018
Canada 30 year Bond Rate	3.20% Spring 2017 & Winter 2017	2.90% Winter 2018
MH 30 Year Bond Rate	4.20% Winter 2017	3.90% Winter 2018
MH Long Term Interest Rate		
12 Year WATM	3.65% Winter 2017	3.45% Spring 2017
20 Year WATM	4.00% Winter 2017	3.80% Winter 2018

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Appendix 1. In addition to the further line item breakdown provided on the Cash Flow Statement, the “Other” category balance of $11 million in 2017/18 under Financing Activities represents the advance to Centra which is eliminated upon consolidation. The “Other” category of $3 million under Investing Activities is primarily investments in assets held for sale as well as payments associated with various obligations.

2.4.6 Operating & Administrative Costs

Consistent with Exhibit 93, Manitoba Hydro’s preliminary O&A target included in the 2019/20 Interim Budget is $511 million reflecting an inflationary increase of 2% over the $501 million of O&A expenses included in the 2018/19 Financial Outlook. The 2% increase is aligned with Manitoba CPI. Manitoba Hydro is committed to achieving this level of O&A expenditure and is in the process of developing detailed budgets for 2019/20 to support this commitment.

As discussed in the 2017/18 & 2018/19 GRA, the implementation of a significant work force reduction strategy resulted in cost reductions in both 2017/18 and 2018/19. As shown in Figure 2.11, O&A costs were $19 million lower in 2017/18 than the prior year and are projected to be further reduced by $16 million in 2018/19.

Figure 2.11: Year over Year Comparison of O&A Costs

(in millions of dollars)	2016/17 Actual	2017/18 Actual	2018/19 Budget	2019/20 Forecast
O&A Expenditures	$536	$517	$501	$511
Year over Year Inc / (Dec)		-3.5%	-3.1%	2.0%

The year over year decreases in 2017/18 and 2018/19 are primarily due to the impact of the Voluntary Departure Program (“VDP”) which was launched in April 2017 as a means to accomplish the Corporation’s workforce reduction target of 900 employees over a 3 year period ending March 31, 2020. A total of 821 employees were approved under the VDP with the majority of staff departing by March 2018. Manitoba Hydro’s headcount as of April 2017, excluding summer students and seasonal workers, was approximately 6150. The Corporation's projected headcount to March 2020 is approximately 5250.

Appendix 8 provides Manitoba Hydro's O&A Expenses Quarterly Report for the year ending March 31, 2018 as well as the quarters ending June 30th and September 30th 2018, filed in response to Directive 14 of Order 73/15. O&A performance to the end of September 2018 is closely aligned with budget. The September 30, 2018 report provides information for the 2018/19 annual budget by cost element.

2.4.7 Impacts of VDP on Pension

At March 31, 2018 Manitoba Hydro recognized a $30 million actuarial loss in Other Comprehensive Income (OCI) related to the VDP departures based on a December 2017 valuation of the pension liability. The loss is primarily a result of deviations in pension valuation assumptions. The pension valuation assumes age 59 as the average age of retirement and that pensioners will take a monthly pension payment. Individuals retiring as part of the VDP who were 55-58 years of age at retirement had a negative impact on the pension valuation as did individuals who withdrew the commuted value of their pension. Manitoba Hydro's actuary (Ellement Consulting) estimates that annual pension payments will increase by approximately $1 million per year once all the VDP individuals have retired and the current service rate is expected to decrease by 5% by 2019. Additional actuarial losses on the pension obligation of approximately $30 million and $7 million are projected for March 2019 and March 2020 respectively using fiscal 2017/18 VDP valuation impacts as a proxy.

2.5 Capital Expenditure Forecast (CEF18)

Appendix 6 contains a copy of Manitoba Hydro's Capital Expenditure Forecast (CEF18) from 2018/19 to 2027/28. CEF18 identifies all projects greater than $1 million in response to Directive 15 of Order 73/15. Projects greater than $15 million appear in the body of the report and projects less than $15 million are summarized in Appendix II of the report.

Figure 2.12 provides a comparison of CEF18 to CEF16 for Electric operations, which shows a decrease of $303.6 million over the 10 year period to 2027/28.

REFERENCE:

Appendix 8, 2017/18 GRA Tab 6 Figure 6.4 Operating and Administrative Expense breakdown

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Update Figure 6.14 from the 2017/18 GRA including actuals, and updated detailed forecast for 2017/18, 2018/19 and provide the compound annual growth by cost element from 2016/17 actual to 2018/19 forecast.
b) Update (a) and include the detail of 2019/20 Interim Budget OM&A expenditures by cost element and provide the compound annual growth from 2016/17 actual to 2019/20 forecast and explain all variances.

RESPONSE:

a) The following table provides an update to Figure 6.14 of the 2017/18 GRA to include actual expenditures for 2016/17 and 2017/18, the 2018/19 Outlook and the compound annual growth by cost element from 2016/17 to 2018/19. As discussed during the 2017/18 GRA, a detailed forecast for 2017/18 was not prepared, and therefore, cannot be provided, as the corporation was undergoing a restructuring program which affected the structure and responsibilities/accountabilities of the Corporate/Operating groups.

b)

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Outlook	Compound Annual Growth 2016/17-2018/19
Employee Related Expenditures						
Wages & salaries	$ 493 346	$ 506 811	$ 517 311	$ 493 691	$ 469 597	-4.7%
Overtime	69 541	67 982	72 256	75 095	76 642	3.0%
Employee benefits	166 854	159 363	165 924	156 884	145 225	-6.4%
Other	73 067	70 832	71 943	68 233	73 421	1.0%
Total Employee Related Expenditures	802,809	804,988	827,435	793,903	764,885	-3.9%
Less: Capitalized Labor & Overhead	(313 931)	(322 144)	(345 763)	(336 397)	(332 292)	-2.0%
Operational Employee Related Expenditures	488 877	482 844	481 672	457 507	432 593	-5.2%
External services and materials	126 850	127 711	126 024	122 843	130 905	1.9%
Donations, sponsorships & grants	2 804	2 592	2 134	2 434	2 140	0.2%
Uncollectible accounts	4 890	5 748	4 266	12 375	4 265	0.0%
Other	452	6 215	2 820	1 200	9 188	80.5%
Cost recoveries	(15 115)	(15 789)	(15 706)	(16 387)	(14 593)	-3.6%
O&A charged to gas operations	(70 355)	(66 607)	(65 384)	(63 112)	(63 315)	-1.6%
Operating and Administrative expenses	$ 538 404	$ 542 714	$ 535 825	$ 516 859	$ 501 183	-3.30%

It is noted that the compound annual growth of 80.5% in the Other line item in the above table is primarily due to funds for transitional business requirements as a result of the voluntary departure program included in the 2018/19 Outlook.

c) The 2019/20 Interim Budget of $511.1 million reflects an inflationary increase of 2% over the 2018/19 Outlook, which is aligned with the Manitoba Consumer Price Index. The details underlying each line item included in the 2019/20 Interim Budget are not available. Following Provincial and MHEB approval of the final 2019/20 budget, Manitoba Hydro will begin developing the detailed forecasts for each component of its 2019/20 budget; these details will be filed with Manitoba Hydro's next full General Rate Application. As indicated on page 28 of the Application, Manitoba Hydro is committed to achieving the O&A forecast included in the 2019/20 Interim Budget.

The following table provides an annual summary of Operating and Administrative actual expenditures from 2014/15 through 2017/18, the 2018/19 Outlook and the 2019/20

Interim Budget. The compound annual growth from 2016/17 to 2019/20 is a decrease of -1.6%, primarily due to the reduction in Manitoba Hydro's workforce.

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
(000's)

	2014/15 Actual	2015/16 Actual	2016/17 Actual	2017/18 Actual	2018/19 Outlook	Compound Annual Growth 2016/17-2018/19	2019/20 Interim Budget	Compound Annual Growth 2016/17-2019/20
Operating and Administrative expenses	$ 538 404	$ 542 714	$ 535 825	$ 516 859	$ 501 183	-3.30%	$ 511 100	-1.60%

REFERENCE:

2017/18 GRA PUB/MH II-6b

PREAMBLE TO IR (IF ANY):

In PUB/MH II-6b, the table provided information by Corporate/Operating group reflecting the organization structure as of April 2017 relating to employees leaving Manitoba Hydro through the VDP program, including the number of employees departing, their current annual salary and a benefit provision. The total savings related to the VDP were then forecast to be $91.9 million annually.

QUESTION:

a) Provide the details of all VDP expenditures
b) Provide the details of all OM&A savings achieved as a result of the VDP, and an explanation as to whether the $92 million in savings has been achieved and if not, why those savings have not been achieved.

RESPONSE:

a) The following table provides a summary of the expenditures incurred for the Voluntary Departure Program in 2017/18 and up to September 2018 of 2018/19, followed by a description of each of the components listed in the table. Minor expenditures are anticipated for the balance of 2018/19 and in early 2019/20.

VDP Expenditures
in thousands of dollars

	2017/18	YTD 30-Sep-18	Cumulative Total
VDP wages & salaries	39 683	504	40 187
VDP benefit allocation	2 976	2 348	5 324
VDP internal costs	226	-	226
Total	**42 885**	**2 852**	**45 737**

- VDP wages & salaries includes the approved VDP payout (bi-weekly salary of an employee multiplied by weeks of service, to a maximum of 30 weeks) as well as current year vacation payouts, where applicable.
- VDP benefit allocation includes an estimate of benefit costs (35% of wage and salary payments) for employees who chose leave with pay instead of a lump sum payment to recognize that staff on leave are eligible for benefit reimbursement (e.g. dental, vision, etc).
- VDP internal costs include incremental overtime costs for staff involved in the administration of the VDP.

b) $92.6 million reflects the total annual employee-related cost savings to be achieved following the departure of all approved applicants. The table below provides an update to the table provided in the response to PUB/MH II-6b of the 2017/18 GRA to include employees seconded to subsidiary operations which were discussed but not previously included in the table. The table reflects the headcount, annual salary and benefit provision as of April 2017 for all employees approved under the VDP by Corporate/ Operating group.

VOLUNTARY DEPARTURE PROGRAM
($ in millions)

	Headcount	Annual Salary	Benefits	Total
President & CEO	1	$ 0.1	$ 0.0	$ 0.1
General Counsel & Corporate Secretary	5	0.6	0.2	0.8
Human Resources & Corporate Services	147	12.3	4.3	16.6
Indigenous Relations	9	0.7	0.2	0.9
Finance & Strategy	33	3.0	1.1	4.1
Generation & Wholesale	157	13.9	4.9	18.8
Transmission	198	16.7	5.8	22.5
Marketing & Customer Service	267	20.8	7.3	28.1
Subsidiary Secondments	4	0.5	0.2	0.6
Total	821	$ 68.6	$ 24.0	$ 92.6

Staff approved under the VDP worked in all functions of the business impacting both capital construction and operations and maintenance work, as a result, the projected annual savings of $92.6 million represent a gross saving (before capitalization) for the corporation. Employee departure dates for approved applicants ranged from June 2017 through January 2019, with 96% of VDP employees having departed the corporation by the end of January 2018. As a result, 2019/20 will be the first year to reflect the full projected annual savings.

REFERENCE:

17/18 & 18/19 GRA - PUB I-14 a), PUB I-11 a) & b), PUB I-15 a), PUB II-8, Appendix 6.6 p.9, Exhibit 78, and Current Application pg 28-29, PUB I-21 b)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) MH Exhibit 78 sets out how the forecast OM&A costs for 2017/18 and 2018/19 were developed for purposes of the last GRA. Please provide the assumed number of departures by March 31, 2018 and March 31, 2019 for both: i) the MH 16 O&A Target Assumptions and ii) the O&A Target Assumptions – Post VDP.

b) Please provide an updated version of Exhibit 78 that: i) for 2017/18 shows the actual results for the year and ii) for 2018/19 provides an updated forecast based on current assumptions regarding the impact of General Wage Increases, Merit & Progression, the impact of the VDP and the impact of the Supply Chain Initiative.

c) Using a similar methodology to that in Exhibit 78 and actual 2017/18 O&A as the starting point, please derive forecasts for 2018/19 and 2019/20 O&A. In doing so, please confirm that the VDP savings for 2018/19 and 2019/20 include the impact of General Wage Increases, Merit & Progression through to those years.

d) Please provide a schedule that sets out for:
   - 2017/18 –the actual number of departures as of March 31, 2018; the actual 2017/18 OM&A savings due to the VDP, and the 2017/18 O&A savings assuming a full year impact for all VDP departures,
   - 2018/19 – the forecast number of departures as of March 31, 2019; the forecast 2018/19 O&A savings due to the VDP and the 2018/19 O&A savings assuming a full year impact for all departures.
   - 2019/20 – the additional impact in 2019/20 arising from the full year effect of the VDP departures in 2019/20.

e) With respect to PUB I-21 b), is the $92.6 M based on salaries and benefits as of April 1, 2017? If yes, what is the comparable savings based on anticipated salaries and benefits in 2019/20? Please reconcile this value with the response to part (d).

f) The response to PUB II-8 states that the OM&A savings through to March 31, 2019 assumed in the last GRA (MH16 Update) were based on an EFT reduction of 500. However, the current Application (page 28) indicates that a total of 821 employees have been approved under the VDP with the majority departing by March 31, 2018. Please reconcile these two numbers.

g) Please provide a detailed quantitative analysis with explanatory notes that reconciles MH evidence from the 2017/18 and 2018/19 GRA that (i) the VDP will generate annual O&A savings of approximately $70 million (Tab 2, Page 51, lines 29 to 31, Tab 3, Page 10, lines 12 to 16) and (ii) the Supply Chain initiative will generate potential cost savings of $150 million from 2017/18 to 2020/21 with 30% related to operational reductions (Tab 3, Page 10, lines 21 to 25), with the level of projected O&A savings included in the 2019/20 O&A target?

h) Of the 821 employees that departed under the VDP, please provide how many positions have been re-filled by MH as well as the associated annualized cost for 2019/20.

RATIONALE FOR QUESTION:

To understand the impacts of the VDP for rate setting purposes.

RESPONSE:

a) The table below provides the assumed number of departures for 2017/18 and 2018/19 for the MH16 O&A Target assumption and the O&A Target assumption – post VDP as per Exhibit 78.

	MH16 O&A Target Assumptions			O&A Target Assumptions Post VDP	
	2017/18	2018/19		2017/18	2018/19
Cumulative Headcount Reductions, as at March 31	235	470		184	554

b) and c)

The table below provides an updated version of Exhibit 78 for the forecast years 2018/19 and 2019/20.

	2018/19	2019/20
2017/18 Actual Results	$ 516.9	$ 516.9
Target Assumption Additions:		
Impact of General Wage Increases, Merit & Progression	9.0	18.2
Manitoba CPI (Non-labour & benefit components)	3.0	6.0
Operating costs for in-service of Bipole III converters	8.4	12.9
Target Assumption Reductions:		
Impact of labour savings through staffing reductions	(33.5)	(34.3)
Sourcing savings through Supply Chain Initiative	(2.7)	(7.0)
Change in capitalization assumptions	(7.2)	(1.3)
$ to address Restructuring (e.g. re-training, IT technology) & potential benefit impacts	7.3	-
O&A Budget	**$ 501.2**	**$ 511.2**

The following assumptions are included in the table above:

- The impact of General Wage increases, Merit and Progression for 2018/19 and 2019/20 is based on staffing levels as of March 31, 2018;
- Manitoba CPI reflects the current forecast of 2.1% for 2018/19 and 2% for 2019/20;
- Operating costs for in-service of Bipole III remains unchanged from previous forecasts;
- Labour savings are based on the salaries of employees who departed the corporation as well as the associated benefit costs;
- Sourcing savings are based on current projections as provided in PUB/MH I-17b with an assumption of 30% allocated to operations, of which 96% is assumed allocated to Electric Operations;
- Change in capitalization assumptions reflects the deployment of staff to capital; and;
- Dollars to address restructuring and potential benefit impacts includes funds set aside for re-training, IT technology changes and changes to benefit costs which may be required following the VDP.

d) The table below provides a summary of the total wage and benefit savings as a result of the VDP as well as the estimated Electric O&A savings for each year based on the number of VDP departures. The full year impact of the VDP departures is reflected in the following year.

MANITOBA HYDRO
VOLUNTARY DEPARTURE PROGRAM SAVINGS
(in millions of dollars)

	Total Employee Departures	Total Wage/Benefit Savings
Voluntary Departure Program (PUB/MH I-21)	821	$ 92.6

	Total Employee Departures	Electric O&A Departures	O&A Savings 2017/18	O&A Savings 2018/19	O&A Savings 2019/20
2017/18	795	458	$ 20.0	$ 52.5	$ 52.5
2018/19	26	15	-	0.9	1.8
2019/20	0	0			
TOTAL	821	473	$ 20.0	$ 53.4	$ 54.3

e) The $92.6 million discussed in PUB/MH I-21b and in part d) above is not based on salaries as at April 1, 2017. The savings were based on the annual salary paid to employees approved under the VDP in 2016/17, as well as associated benefit costs.

Calculating the savings using anticipated salaries and benefits for 2019/20 would not reflect a true savings for the company as these were not a cost incurred by the corporation. The total savings of $54.3 million in part d) above represents the annual O&A savings to the corporation once all employees approved under the VDP have departed.

f) The 821 is the total number of employees accepted under the VDP. As staff may support multiple functions of the business, including capital construction and operations and maintenance, the total reduction and associated savings is not 100% attributable to O&A. As shown in part d) above, the staff reductions attributable to Electric O&A is estimated to be 473 which is comparable to the 500 reduction referenced in the response to PUB/MH II-8 from the 2017/18 and 2018/19 GRA.

g) i. The $70 million of annual O&A savings referenced in the 2017/18 and 2018/19 GRA is comparable to the 2019/20 anticipated O&A savings of approximately $54 million as outlined in response to part d) above. The difference of $16 million is attributable to a change in the O&A savings assumptions. The total savings estimated in the 2017/18 and 2018/19 GRA assumed a 70% impact to O&A, whereas following the VDP, the 2019/20 O&A target reflects an impact closer to 60% based on current experience.

ii. As per Manitoba Hydro's response to COALITION/MH I-107b from the 2017/18 and 2018/19 GRA, the annual sourcing savings was projected to be $45 million in 2019/20 with cumulative total savings of $150 million over the 3-year period from 2017/18 to 2019/20. Tab 3, page 10 of the 2017/18 and 2018/19 GRA indicated that approximately 70% of savings relate to capital purchases and the remaining 30% relate to operational purchases. As such, cumulative O&A savings would equate to approximately $45 million (30% of $150 million).

As per PUB/MH I-17a-b the total cumulative savings to the end of 2017/18 were $22 million plus an additional $24 million to the end of 2019/20. Assuming 30% of the savings relate to operational purchases, this would equate to $14 million of O&A savings. The difference between the $45 million assumed in the 2017/18 and 2018/19 GRA and the $14 million in the 2019/20 O&A target is attributable to the following:

- The savings identified in PUB/MH I-17 are calculated at the contract level whereas a portion of the $45 million were efficiency savings that cannot be quantified. For example, improving supplier relationship management to optimize time spent on employee/supplier interaction.
- As discussed in the response to COALITION/MH I-107a from the 2017/18 and 2019/29 GRA, Manitoba Hydro initially engaged a consultant as part of the Supply Chain Performance Management Program. The corporation has chosen not to renew the engagement and as such, the savings are expected to be realized over a longer period of time.

h) A total of 821 employees will leave the corporation under the VDP by the end of 2018/19. The VDP was open to all employees and as such, departments were impacted differently depending on the number of employees accepted within each department. Following the VDP, the corporation extensively reviewed its organizational structure and functions and as a result of the review, realigned remaining staff to positions where the job duties/responsibilities were deemed most essential. As a result, the impact of the VDP cannot be measured by the number of positions that existed before and after the VDP as suggested in the question.

The impact of the VDP is more accurately reflected in the Corporation's EFT performance. The number of straight-time EFTs to the end of December 2018 was 5,334 compared to 6,206 EFTs (referenced in PUB/MH I-23b) that existed prior to the start of the VDP in 2016/17.

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REFERENCE:

Appendix 1; PUB/MH 1, MIPUG/MH I-6b (2017/18 GRA)

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Supplement the schedule provided to include the opening and closing balances of each regulatory deferral account.
b) Provide details of and explain the site restoration costs forecast for 2018/19 and 2019/20 and compare with the forecast of those costs for those years presented at the last GRA.
c) Provide a comparison of the details of additions and amortizations to regulatory deferral accounts for 2017/18, 2018/19 and 2019/20 and explain the differences.

RESPONSE:

a) Please see the following for a continuity schedule providing the opening and closing balances for each regulatory deferral account.

Manitoba Hydro

Manitoba Hydro 2019/20 Electric Rate Application
PUB/MH I-10a-c (Updated)

Manitoba Hydro
Supplement to the 2019/20 Electric Rate Application
(In thousands of dollars)

	Actual 2017/18	Current Outlook 2018/19	Approved Budget 2019/20
Opening balance of net regulatory deferral			
Demand side management expenses	204 389	232 283	257 481
Site restoration costs	27 956	25 697	29 125
Regulatory costs	5 410	14 026	11 438
Acquisition costs	9 788	9 096	8 404
Change in depreciation method	90 827	123 097	161 836
Deferred ineligible overhead	60 600	78 721	96 309
Loss on disposal of assets	9 641	18 175	20 175
Affordable Energy Fund	4 164	4 043	3 385
Discontinuance of Conawapa Generating Station	-	379 204	366 577
DSM deferral debit balance	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)
	412 775	884 342	954 730
Additions to regulatory deferral accounts			
Demand side management expenses	63 667	62 539	61 219
Site restoration costs	1 221	7 355	6 722
Regulatory costs	10 136	1 733	5 282
Acquisition costs	-	-	-
Change in depreciation method	32 270	38 739	41 776
Deferred ineligible overhead	20 200	20 200	20 200
Loss on disposal of assets	8 534	2 000	2 000
Affordable Energy Fund	76	-	
Discontinuance of Conawapa Generating Station	379 204	-	-
DSM deferral debit balance	-		
DSM deferral credit balance	-		
	515 308	132 566	137 199
Amortization of regulatory deferral accounts			
Demand side management expenses	(35 773)	(37 341)	(40 195)
Site restoration costs	(3 480)	(3 927)	(4 065)
Regulatory costs	(1 520)	(4 321)	(4 493)
Acquisition costs	(692)	(692)	(692)
Change in depreciation method	-	-	-
Deferred ineligible overhead	(2 079)	(2 612)	(3 206)
Loss on disposal of assets	-	-	(1 059)
Affordable Energy Fund	(197)	(658)	(437)
Discontinuance of Conawapa Generating Station	-	(12 627)	(12 627)
DSM deferral debit balance	-	-	-
DSM deferral credit balance	-	-	-
	(43 741)	(62 178)	(66 774)
Closing balance of net regulatory deferral			
Demand side management expenses	232 283	257 481	278 505
Site restoration costs	25 697	29 125	31 782
Regulatory costs	14 026	11 438	12 227
Acquisition costs	9 096	8 404	7 712
Change in depreciation method	123 097	161 836	203 612
Deferred ineligible overhead	78 721	96 309	113 303
Loss on disposal of assets	18 175	20 175	21 116
Affordable Energy Fund	4 043	3 385	2 948
Discontinuance of Conawapa Generating Station	379 204	366 577	353 950
DSM deferral debit balance	48 800	48 800	48 800
DSM deferral credit balance	(48 800)	(48 800)	(48 800)
	884 342	954 730	1 025 155

b) Please see the following schedule for the details comprising site restoration costs for the 2018/19 Current Outlook and the 2019/20 Approved Budget and for those same years as presented at the last GRA (MH16 Update with Interim). Explanations for the differences are provided below the schedule.

	Manitoba Hydro Supplement to the 2019/20 Electric Rate Application		Manitoba Hydro 2017/18 & 2018/19 GRA MH16 Update with Interim			
(In thousands of dollars)	**2018/19 Current Outlook**	**2019/20 Approved Budget**	**2018/19 Forecast**	**2019/20 Forecast**	**2018/19 Difference**	**2019/20 Difference**
Site Restoration Costs						
8 and 2 Mile Channel cleanup	5 488	4 490	949	280	4 539	4 210
South Bay construction camp	150	185	904	280	(754)	(95)
Other	1 717	2 047	850	852	867	1 196
	7 355	**6 722**	**2 703**	**1 412**	**4 652**	**5 310**

2018/19 Current Outlook vs. 2018/19 MH16 Update with Interim

The increase in the 2018/19 Current Outlook compared to the 2018/19 MH16 Update with Interim Forecast filed at the last GRA is due primarily to an increase in the spending for the 8 & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations which identified additional work to be performed. In addition, the 2018/19 Current Outlook for Other site restoration costs is higher due to efforts required to review and address any issues associated with the recent closures of rural district offices and to accommodate the replacement of aging infrastructure. These increases are partially offset by a reduction in the 2018/19 Current Outlook for the South Bay construction camp as the plans for this site have been delayed subject to further studies and discussions with the community.

2019/20 Approved Budget vs. 2019/20 MH16 Update with Interim

The increase in the 2019/20 Approved Budget compared to the 2019/20 MH16 Update with Interim Forecast is due primarily to increased spending for the 8 & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations. The 2019/20 Approved Budget for Other site restoration costs is higher due to efforts required to review and address any issues associated with the recent closures of rural district offices and to accommodate the replacement of aging infrastructure.

c) Please see the following schedule which details the additions and amortization to regulatory deferral accounts for 2017/18 actuals, 2018/19 Current Outlook and 2019/20 Approved Budget compared to the previous MH16 Update with Interim Forecast for those same years. Explanations as to the year over year differences are provided below.

Manitoba Hydro 2019/20 Electric Rate Application
PUB/MH I-10a-c (Updated)

(In thousands of dollars)	Manitoba Hydro Supplement to the 2019/20 Electric Rate Application Actual 2017/18	Current Outlook 2018/19	Approved Budget 2019/20	Manitoba Hydro MH16 Update with Interim Forecast 2017/18	Forecast 2018/19	Forecast 2019/20	2017/18 Difference	2018/19 Difference	2019/20 Difference
Additions to regulatory deferral accounts									
Demand side management expenses	63 667	62 539	61 219	57 184	99 404	94 251	6 483	(36 865)	(33 032)
Site restoration costs	1 221	7 355	6 722	2 794	2 703	1 408	(1 573)	4 652	5 314
Regulatory costs	10 136	1 733	5 282	3 664	2 339	1 339	6 472	(606)	3 943
Acquisition costs	-	-	-	-	-	-	-	-	-
Change in depreciation method	32 270	38 739	41 776	33 952	39 506	42 869	(1 682)	(767)	(1 093)
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-
Loss on disposal of assets	8 534	2 000	2 000	-	-	-	8 534	2 000	2 000
Affordable Energy Fund	76	-		-	-	-	76	-	-
Discontinuance of Conawapa Generating Station	379 204	-	-	-	-	379 758	379 204	-	(379 758)
	515 308	**132 566**	**137 199**	**117 794**	**164 152**	**539 825**	**397 514**	**(31 586)**	**(402 626)**
Amortization of regulatory deferral accounts									
Demand side management expenses	(35 773)	(37 341)	(40 195)	(35 742)	(36 662)	(43 202)	(31)	(679)	3 007
Site restoration costs	(3 480)	(3 927)	(4 065)	(4 106)	(3 990)	(3 855)	626	63	(210)
Regulatory costs	(1 520)	(4 321)	(4 493)	(2 942)	(3 665)	(2 884)	1 422	(656)	(1 609)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	-	-	-
Change in depreciation method	-	-	-	-	-	(6 437)	-	-	6 437
Deferred ineligible overhead	(2 079)	(2 612)	(3 206)	(1 768)	(4 545)	(5 555)	(311)	1 933	2 349
Loss on disposal of assets	-	-	(1 059)	(288)	(577)	(577)	288	577	(482)
Affordable Energy Fund	(197)	(658)	(437)	(449)	(480)	(563)	252	(178)	126
Discontinuance of Conawapa Generating Station	-	(12 627)	(12 627)	-		(11 592)	-	(12 627)	(1 035)
	(43 741)	**(62 178)**	**(66 774)**	**(45 987)**	**(50 611)**	**(75 357)**	**2 246**	**(11 567)**	**8 583**

Year over Year Explanations

2017/18 Actual vs. 2017/18 MH16 Update with Interim Forecast

Additions:

The 2017/18 additions were higher than the MH16 Update with Interim Forecast primarily as a result of the March 31, 2018 transfer of the Conawapa Generating Station ("GS") development costs from Construction Work in Progress ("CWIP") to a regulatory deferral account, as per PUB Order 59/18. The forecast had assumed this transfer would occur in fiscal 2019/20. In addition, losses on the disposal of assets were higher as the forecast did not include a projection for losses. The losses are the result of the retirement of equipment at the Limestone GS and the St. James station, as well as the retirement of street lights replaced with LED bulbs. The 2017/18 DSM spending was higher than the forecast due to greater than anticipated take up in commercial lighting and solar technology programs, as well as higher than projected installations of LED roadway lighting. Actual regulatory costs for the 2017/18 & 2018/19 GRA were also higher than the forecast.

Amortization:

The 2017/18 amortization was lower than the MH16 Update with Interim Forecast primarily as a result of the amortization of the 2017/18 & 2018/19 GRA regulatory costs commencing in June 2018 to coincide with the implementation date of the rate increase, as compared to the October 2017 date assumed in the forecast. In addition, there was lower amortization for site restoration costs as the previous year's site restoration costs were lower than projected.

2018/19 Current Outlook vs. 2018/19 MH16 Update with Interim Forecast

Additions:

The additions for the 2018/19 Current Outlook are lower than the MH16 Update with Interim Forecast due primarily to a reduction in planned DSM spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba. The reduction in DSM spending is partially offset by increases in site restoration costs due to additional work for the 8 & 2 Mile Channel as identified in recent environmental and geophysical investigations.

Amortization:

The amortization for the 2018/19 Current Outlook is higher than the MH16 Update with Interim Forecast primarily as a result of the timing of the deferral of the Conawapa GS regulatory account as discussed above. This increase is partially offset by the decrease in the amortization of the ineligible overhead which is being amortized over a 34 year period (as per PUB Order 59/18) compared to the 20 year period assumed in the forecast.

2019/20 Approved Budget vs. 2019/20 MH16 Update with Interim Forecast

Additions:

The additions for the 2019/20 Approved Budget are lower than the balances presented in the MH16 Update with Interim Forecast primarily due to the difference in the timing of the transfer of the Conawapa CWIP costs to a regulatory deferral account and the reduction to planned DSM spending as a result of the deferral of new programs and initiatives pending the transition to Efficiency Manitoba. This decrease is partially offset by an increase in projected spending for site restoration costs as discussed above.

Amortization:

The amortization for the 2019/20 Approved Budget period is lower than the MH16 Update with Interim Forecast primarily due to the reduction in the annual amortization of the change in depreciation method (ASL vs. ELG) regulatory deferral account. The depreciation deferral account is not being amortized (as per PUB Order 59/18) as compared to the 20 year period (commencing in 2019/20) assumed in the forecast. In addition, the amortization for DSM expenditures is lower compared to forecast due to the planned reductions in DSM expenditures in 2018/19. The amortization for the ineligible overhead account is lower due to the use of a 34 year amortization period as discussed above. These decreases are partially offset by an increase in the amortization of regulatory costs reflecting the higher than planned expenditures for the 2017/18 & 2018/19 GRA.

REFERENCE:

Current Application p. 16-27, 23-24 & Attachment 2, 17/18 & 18/19 GRA Exhibit 93, PUB I-10

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide, for the years 2017/18 through 2019/20, a revised version of PUB I-10c) that compares the Current Application with Exhibit 93 from the last GRA. For each regulatory deferral account, please also indicate (where applicable) under what expense item the cost being transferred to the regulatory deferral account is reported on the Income Statement (e.g., Change in Depreciation Method amounts are reported under Depreciation and Amortization).

b) For each deferral account, please explain any changes (in either annual additions or amortization) as between the response to part (a) and the Current Application as set out in Attachment 2. In particular, please highlight those changes that are due to Exhibit 93 not fully reflecting the Directives in Order 59/18.

c) Please confirm that in the Current Application the forecast for Net Movement reflects all of the Board's Directives with respect to regulatory deferrals and amortizations. If not, which directives are not incorporated and why.

RATIONALE FOR QUESTION:

To understand the changes in Net Movement since the last GRA.

RESPONSE:

a) Please see the following revised schedule of PUB/MH I-10c which provides the additions and amortization of regulatory deferral accounts for the years 2017/18 through 2019/20 per the Supplement to the 2019/20 Electric Rate Application compared to Exhibit 93. The expense item on the Income Statement that the cost is transferred from to the regulatory deferral account is also provided.

Manitoba Hydro

Manitoba Hydro 2019/20 Electric Rate Application
COALITION/MH I-16a-c

	Manitoba Hydro Supplement to the 2019/20 Electric Rate Application			Manitoba Hydro Exhibit 93					
(In thousands of dollars)	2017/18 Actual	2018/19 Current Outlook	2019/20 Approved Budget	2017/18 Forecast	2018/19 Forecast	2019/20 Forecast	2017/18 Difference	2018/19 Difference	2019/20 Difference
Additions to regulatory deferral accounts									
Other Expenses									
Demand side management expenses	63 667	62 539	61 219	57 184	99 404	94 251	6 483	(36 865)	(33 032)
Site restoration costs	1 221	7 355	6 722	2 794	2 703	1 408	(1 573)	4 652	5 314
Regulatory costs	10 136	1 733	5 282	3 664	2 339	1 339	6 472	(606)	3 943
Discontinuance of Conawapa Generating Station	379 204	-	-	-	-	379 758	379 204	-	(379 758)
Depreciation and Amortization									
Change in depreciation method	32 270	38 739	41 776	33 952	39 506	42 869	(1 682)	(767)	(1 093)
Loss on disposal of assets	8 534	2 000	2 000	-	-	-	8 534	2 000	2 000
Operating and Administrative									
Deferred ineligible overhead	20 200	20 200	20 200	20 200	20 200	20 200	-	-	-
Finance Expense									
Affordable Energy Fund	76	-	-	-	-	-	76	-	-
	515 308	**132 566**	**137 199**	**117 794**	**164 152**	**539 825**	**397 514**	**(31 586)**	**(402 626)**
Amortization of regulatory deferral accounts									
Demand side management expenses	(35 773)	(37 341)	(40 195)	(35 742)	(36 662)	(43 202)	(31)	(679)	3 007
Site restoration costs	(3 480)	(3 927)	(4 065)	(4 106)	(3 990)	(3 855)	626	63	(210)
Regulatory costs	(1 520)	(4 321)	(4 493)	(2 942)	(3 665)	(2 884)	1 422	(656)	(1 609)
Acquisition costs	(692)	(692)	(692)	(692)	(692)	(692)	-	-	-
Change in depreciation method	-	-	-	-	-	-	-	-	-
Deferred ineligible overhead	(2 079)	(2 612)	(3 206)	(1 177)	(3 020)	(3 687)	(902)	408	481
Loss on disposal of assets	-	-	(1 059)	(288)	(577)	(577)	288	577	(482)
Affordable Energy Fund	(197)	(658)	(437)	(449)	(480)	(563)	252	(178)	126
Discontinuance of Conawapa Generating Station	-	(12 627)	(12 627)	-		(11 592)	-	(12 627)	(1 035)
	(43 741)	**(62 178)**	**(66 774)**	**(45 396)**	**(49 086)**	**(67 052)**	**1 655**	**(13 092)**	**278**

b) Please see below for explanations of any significant changes in additions or amortization between the information provided in the Supplement to the 2019/20 Electric Rate Application and Exhibit 93 from the last GRA.

Demand side management

The 2017/18 DSM spending was higher than the forecast due to greater than anticipated take up in commercial lighting and solar technology programs, as well as higher than projected installations of LED roadway lighting. The additions for the 2018/19 Current Outlook are lower than the Exhibit 93 Forecast due to a reduction in planned spending resulting from lower projections for customer activity under the Load Displacement program and a deferral of programs pending the transition to Efficiency Manitoba. The additions for the 2019/20 approved budget are lower than the Exhibit 93 forecast reflecting the continuation of current DSM program offerings while responsibility for DSM transitions to Efficiency Manitoba. Amortization in 2019/20 is lower as a result of the reduced spending in the 2018/19 Current Outlook as amortization of DSM expenditures commences the following fiscal year.

Site restoration

The increase in additions for 2018/19 and 2019/20 is due primarily to increased spending for the 8 Mile Channel & 2 Mile Channel projects as supported by more recent environmental and geophysical investigations.

Regulatory costs

Actual 2017/18 regulatory costs/activities for the 2017/18 and 2018/19 GRA were significantly higher than the initial projection provided in the Exhibit 93 forecast. The 2019/20 Approved budget further anticipates an increase in regulatory costs/activities for upcoming GRA's as compared to those included in the forecast in Exhibit 93.

Conawapa

The 2017/18 additions were higher than Exhibit 93 primarily as a result of the March 31, 2018 transfer of the Conawapa Generating Station development costs from Construction Work in Progress to a regulatory deferral account, for compliance with Directive 19 in PUB Order 59/18. The forecast for Exhibit 93 had assumed this transfer would occur in fiscal 2019/20. The timing of this transfer also impacts the projected difference in amortization for the 2018/19 and 2019/20 years.

Loss on disposal of assets

Losses on the disposal of assets were higher in 2017/18 as the Exhibit 93 forecast did not include a projection for losses. The losses are the result of the retirement of equipment at the Limestone Generating Station and the St. James station, as well as the retirement of street lights replaced with LED bulbs. For the 2018/19 and 2019/20 years the Supplement to the 2019/20 Electric Rate Application includes amounts for losses on terminal retirements. These terminal retirement losses are assumed to be amortized over a period of 20 years commencing in the 2019/20 year, consistent with the assumption in Exhibit 93 which amortizes asset retirement losses incurred prior to 2017/18 over 20 years.

Deferred ineligible overhead

In the Supplement to the 2019/20 Electric Rate Application the amortization of deferred ineligible overhead is over 34 years for compliance with Directive 21 in PUB Order 59/18. The forecast underlying Exhibit 93 assumed an amortization of 30 years for ineligible overhead.

c) It is confirmed that in the Supplement to the 2019/20 Electric Rate Application forecast Net Movement reflects all of the PUB's Directives with respect to regulatory deferrals and amortization.