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Tab #	Description	Reference
Capital Expenditure		
1	Major Generation & Transmission Projects Progression of Capital Costs	PUB/MH I-17(c), PUB/MH I-25(a)
2	Bipole III	Appendix 4.1 CEF14 PUB/MH I-20(e), Attachment 5 PUB/MH I-20(e), Attachment 6 PUB/MH I-20(e), Attachment 7 PUB/MH I-20(e), Attachment 8 PUB/MH -019A MH Signed CPJ Bipole III Capital Project Justification.pdf Bipole III Capital Cost Estimates NFAT Transcript Excerpt from March 11, 2014 - Bipole III PUB/MH II-74(a-c) PUB/MH II-11(c-d) PUB/MH II-12(a-b) PUB/MH II-13(a-d)
3	Keeyask G.S. Cost Progression Construction Contracts	PUB/MH I-24(b), Attachment 1 PUB/MH I-24(b), Attachment 2 Coalition/MH I-19(f) PUB/MH II-16(a-b)
4	Keeyask G.S. Construction Contracts	Coalition/MH I-19(f)
5	Point du Bois G.S. Re-Build	Appendix 4.1 CEF14 MH Exhibit 98 CEF13 PUB/MH II-17 - Point Du Bois Canada-utility-seeks-turbine-generator, Hydroworld.com MH Exhibit 204, p117, Final NFAT Arguments MH-Exhibit 129-7 NFAT Excerpt
6	Sustaining Capital Spending	Coalition/MH I-32(b) Appendix 11.37 MFR4, p2 PUB/MH II-50(b)-2012 GRA PUB/MH I-22(c)-2012 GRA PUB/MH II-39

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Tab #	Description	Reference
7	Capital Spending on Existing Hydraulic Generation	Coalition/MH I-37(b) Coalition/MH I-28(b) Coalition/MH I-32(b)
8	Sustaining Capital	Appendix 11.15 MFR #9, pp 4-6
9	Internally Generated Funds	Appendix 11.37 MFR #4, p 2 PUB/MH I-22(c)-2012 GRA Coalition/MH I-28(a)
10	Conawapa G.S.	PUB/MH I-23(c) PUB/MH II-10 PUB/MH I-238(c), NFAT
11	Capital Expenditures – WPLP Debt	PUB/MH II-6 Appendix 11.15 MFR #9, pp 4-6 Estimated Impacts of Wuskwatim on Net Income 2012 GRA
12	Capital Expenditures – KHPLP Debt	PUB/MH II-7, pp3-4
Transmission		
13	Great Northern Transmission Line – US Expansion	The Globe & Mail, April 30, 2015; Canadian Hydro Power and the Clean Power Plan (April 2015); App 11-15 In service costs (p.4);
14	Manitoba Minnesota 500 kV. Transmission Line	Power Resource Plan: PUB/MH I-58 p.13; PUB/MH I-17c; App 11-15 p.4;
15	Bipole III	App 3.3 section 6 page 8; PUB/MH I-66 a and b; PUB/MH II-38 a to d; App 11-46 (NFAT Exhibits 176-1 and 176-2);
16	Additional North South Transmission Upgrades	CEF13 Major New G&T p.3; CEF 14 Major New G&T p.3;
17	Bipole I and Bipole II	CEF 13 and CEF14; Coalition/MH II-53 c to g; Transmission Asset Condition Assessment Report (Kinectrics);

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Tab #	Description	Reference
18	Asset Condition Report	MH Report on Kinectrics Report, January 23, 2013; PUB/MH I-19 b, APP 4.2, App c Transmission Detailed Methodology;
19	System Utilization	PUB/MH ? Attached Graph B2
20	Tariff Revenues/Costs	Unit Revenues Cost Calculations for IFF14, App 11-19 p.3; IFF13 APP 11-19 p.4;
Curtailable Rate Program		
21	Curtailable Rates Program (CRP) Report	April 1, 2013 – March 31, 2014 Report to PUB; PUB/MH I-58 Power Resource Plan (No New Resource) pp. 17, 18; PUB/MH I-58 p.8 of 24;
22	CRP Winter and Summer Demand	App. 11-48 Revised, pp.2 and 5
23	CRP Winter 2013/14	PUB/MH II- 37 a to d

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Section:	Tab 4: Appendix 11.35 & 11.36	Page No.:	
Topic:	Capital Expenditures		
Subtopic:	Construction work in progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's total capital expenditures have shown material changes and are a major driver behind requested rate increases.

QUESTION:

Please provide an update to PUB/MH I-93 (a) from the 2012 GRA to include CEF12, CEF13 and CEF14. Please total the schedule.

RATIONALE FOR QUESTION:

This Information Request seeks background information on capital cost escalation.

RESPONSE:

Please see the following table.

Progression of Project Costs in $ M												
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF-10	CEF-11-2	CEF-12	CEF-13	CEF-14
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275	1,275	1,375	1,449	1,449	1,449
Wuskwatim Transmission		199	200	257	320	316	316	291	298	323	320	320*
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591	1,566	1,673	1,771	1,768	1,768
Herblet Lake Transmission	57	55	54	54	95	93	93	75	75	77	76	76*
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248	3,280	3,280	3,280	3,280	4,653
Riel C.S.	96	101	103	103	105	268	268	268	268	268	330	330
Kelsey G.S.	121	121	166	166	184	190	190	302	302	302	302	340
Kettle G.S.		61	61	61	61	76	76	166	166	166	166	192
Pointe du Bois Spillway							318	398	398	560	560	575
Pointe du Bois Trans.					83	86	86	86	86	86	114	114
Pointe du Bois Rebuild	421	288	692	834	818	818		1,538	1,538	1,538	1,538	1,852
Slave Falls G.S.				179	192	198	198	223	230	230	126	126
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325	7,771	7,771	10,192	10,492	397
Keeyask G.S.						3,700	4,592	5,637	5,637	6,220	6,220	6,496
500 KV Dorsey U.S. Border						205	205	205	205	205	350	350
Total	2,043	7,154	9,742	10,957	11,954	16,042	17,781	23,081	23,302	26,665	27,091	19,038

*Wuskwatim Transmission and Herblet Lake Transmission Projects are in-service and have no further capital spending. These projects were removed from CEF14 but included in this table for completeness.

Section:	Tab 4:	Page No.:	
Topic:	Capital Expenditure Forecast		
Subtopic:	Projects in excess of $5 million		
Issue:	Changes in CEF		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a list of all projects over the 2012/13 to 2023/24 period where the total project costs have changed as between CEF11-2 and CEF14 and the current total project cost exceeds $5M. Where the difference is more than 5% please provide an explanation.

RATIONALE FOR QUESTION:

To understand the changes in capital expenditure costs of major projects.

RESPONSE:

The table below provides a list of all projects over the 2012/13 to 2023/24 period where the total project costs have changed from CEF12 to CEF14 and the current total project cost exceeds $5M. Where the difference is greater than 5% an explanation is provided below the table.

Projects *(in millions of dollars)*	CEF12 Total Cost	CEF14 Total Cost	Increase/ (Decrease) in CEF	Percentage Increase/ (Decrease)	Reference
Conawapa - Generation	10,192.4	397.0	(9,795.4)	-96%	1
Kelsey Improvements & Upgrades	301.7	340.4	38.6	13%	2
Kettle Improvements & Upgrades	165.7	191.6	25.9	16%	3
Pointe du Bois - Transmission	85.9	114.3	28.4	33%	4
Pointe du Bois Powerhouse Rebuild	1,538.3	1,852.2	313.9	20%	5
Gillam Redevelopment and Expansion Program (GREP)	366.5	266.5	(100.0)	-27%	6
Riel 230/500kV Station	267.6	329.9	62.4	23%	7
Manitoba-Minnesota Transmission Project	204.8	350.3	145.6	71%	8
Generating Station Improvements & Upgrades	98.3	138.6	40.3	41%	9
Great Falls Unit 4 Overhaul	43.2	53.6	10.5	24%	10
New Madison Station - 115/24kV Station	65.9	87.1	21.2	32%	11
Burrows New 66/12kV Station	42.6	54.7	12.1	28%	12
Bipole III - Transmission Line	1,259.9	1,655.4	395.5	31%	13
Bipole III - Converter Stations	1,828.5	2,675.1	846.6	46%	13
Bipole III - Collector Lines	191.4	260.2	68.7	36%	13

1. Conawapa – Generation: The decrease reflects suspension of construction activities pending re-evaluation of the business case. Remaining expenditures are for the wrap up of preliminary engineering studies and limited environmental and aboriginal studies including capitalized interest on construction in process through August 2016.

2. Kelsey Improvements & Upgrades: The increase is primarily related to deficiency work on the head covers of all seven units required to improve safety and reliability. In addition, increased costs for wastewater treatment upgrades.

3. Kettle Improvements & Upgrades: The increase reflects actual costs incurred for Unit 4 including scope increases for thrust runner replacements, new excitation transformer, rebabitting of bearings and the removal and disposal of the old stator for units 1-4.

4. Pointe du Bois – Transmission: The increase is primarily related to a change in concept for replacement of the 66kV lines from Pointe du Bois to Rover Stations as well as increased costs for the Stafford Stations rebuild and Pointe du Bois Bank 7 replacement.

5. Pointe du Bois Powerhouse Rebuild: The increase is primarily to reflect revised interest and escalation costs as a result of the deferral of the in-service date to 2039/40.

6. Gillam Redevelopment and Expansion Program (GREP): The decrease reflects a re-evaluation of the project resulting in cost reductions due to optimization of the project through a re-design of the town centre, residential site development, trailer park and industrial park as well as a re-analysis of customer requirements resulting in a reduction in the scope of work.

7. Riel 230/500kV Station: The increase is primarily related to incorporation of awarded contracts amounts and a deferral of the in-service date from May 2014 to October 2014.

8. Manitoba-Minnesota Transmission Project: The increase reflects additional line length and a scope increase for a phase shifting transformer and the associated transmission line re-alignment at Glenboro Station.

9. Generating Station Improvements & Upgrades: The increase reflects an increased provision for overhauls at northern generating stations.

10. Great Falls Unit 4 Overhaul: The increase reflects additional work to refurbish the service bay floor, upgrade line protection as a result of an Interconnection Study, upgrade the powerhouse crane, repair a damaged draft tube elbow as well as increased interest costs associated with a delay in in-service.

11. New Madison Station – 115/24kV Station: The increase reflects scope changes requiring installation of new cable, re-design of the 115kV terminations, addition of special bus bar connections, modification of the existing switchgear, relocations of circuits, and protection upgrades. In addition, awarded contract prices and updated interest and escalation were included.

12. Burrows New 66/12kV Station: The increase reflects a deferral of the project in-service date from March 2013 to March 2015 as well as increased costs to complete the feeder conversions and to install a new 66kV underground supply.

13. Bipole III: Please refer to PUB/MH-I-20a for an explanation of the increase in costs.

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CAPITAL EXPENDITURE FORECAST (CEF14)

(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	40.5	12.9	14.7	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	776.3	676.3	962.2	1 351.3	927.9	616.5	208.6	55.2	4.5	0.1	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	1.9	4.7	9.3	6.8	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	43.4	31.4	21.0	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	14.1	9.1	12.9	1.3	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	6.6	23.5	24.6	22.0	31.7	29.5	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	114.1	51.6	3.8	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	15.8	17.1	13.8	4.3	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	-	-	-	-	-
Gillam Redevelopment and Expansion Program (GREP)	266.5	20.0	22.4	22.8	21.8	20.2	18.6	21.3	20.9	19.1	24.6	211.6
Bipole III - Transmission Line	1 655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	36.4	5.6	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	7.0	32.7	99.6	59.5	65.7	48.1	35.4	-	-	-	348.0
Demand Side Management	NA	51.8	59.2	76.6	83.9	93.7	78.2	72.5	60.8	50.0	49.6	676.2
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	2.8	33.0	33.6	34.3	35.0	138.6
Target Adjustment (Cost Flow)	NA	(161.3)	(51.4)	(61.1)	(12.7)	116.3	71.9	50.9	25.6	8.8	0.7	(12.2)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 451.7**	**1 913.9**	**2 463.5**	**2 577.8**	**1 530.9**	**884.0**	**426.2**	**196.1**	**116.6**	**110.0**	**11 670.7**

CAPITAL EXPENDITURE FORECAST (CEF14)

(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	7.2	0.7	14.0	26.4	29.6	40.9	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	2.7	2.7
Slave Falls Major Overhauls	126.1	-	-	-	-	-	2.5	2.4	19.4	18.8	19.9	63.0
Pointe du Bois GS Rehabilitation	182.9	10.1	15.4	47.0	50.0	25.2	9.8	11.2	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	15.8	14.2	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	6.0	0.4	17.5	7.8	18.8	50.4
Base Capital	NA	98.9	101.6	71.0	55.7	77.2	72.7	118.1	97.8	110.7	98.7	902.4
Total	**NA**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**134.6**	**137.3**	**140.1**	**1 336.1**
Transmission												
Rockwood East 230/115kV Station	53.3	26.6	11.1	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	14.2	35.8	8.2	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	1.3	3.7	37.0	13.9	1.6	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	1.0	8.6	8.8	8.9	23.3	23.7	24.2	24.7	27.9	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	8.7	8.5	2.7	5.2	2.2	2.3	2.4	2.7	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	2.1	13.2	22.9	56.9	57.9	59.0	21.8	233.7
Base Capital	NA	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63.0	128.2	777.0
Total	**NA**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**150.0**	**150.0**	**150.0**	**150.0**	**1 350.0**

CAPITAL EXPENDITURE FORECAST (CEF14)

(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	32.6	33.6	12.8	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	0.3	3.0	20.0	20.0	7.9	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	2.4	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	0.7	21.2	22.9	8.8	5.0	3.4	-	-	-	-	62.0
Base Capital	NA	197.0	182.6	209.6	160.7	173.0	193.3	206.0	210.1	214.3	218.6	1 965.3
Total	**NA**	**235.5**	**240.9**	**268.3**	**206.0**	**206.0**	**206.0**	**206.0**	**210.1**	**214.3**	**218.6**	**2 211.8**
Customer Care & Energy Conservation	**NA**	**3.2**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**3.6**	**3.7**	**3.7**	**39.2**
Human Resources & Corporate Services	**NA**	**75.0**	**75.0**	**55.0**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**596.7**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**
		570.9	**577.0**	**584.6**	**522.3**	**522.4**	**522.5**	**547.6**	**554.7**	**562.8**	**571.0**	**5 535.9**
Gas												
Customer Service & Distribution	**NA**	**34.9**	**49.0**	**34.9**	**22.3**	**21.2**	**24.4**	**26.1**	**27.7**	**30.0**	**28.3**	**298.8**
Customer Care & Energy Conservation	**NA**	**3.4**	**5.4**	**4.6**	**4.7**	**4.8**	**4.9**	**5.0**	**5.1**	**5.2**	**5.3**	**48.1**
Gas Demand Side Management	**NA**	**9.6**	**10.4**	**11.0**	**9.4**	**8.7**	**8.9**	**8.9**	**9.3**	**9.5**	**9.9**	**95.5**
		48.0	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**
Major & Base Capital Target Adjustment	NA	-	-	25.0	25.0	25.0	25.0	25.0	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**618.9**	**641.9**	**660.1**	**583.7**	**582.1**	**585.6**	**612.6**	**596.7**	**607.5**	**614.4**	**6 103.4**
CONSOLIDATED CEF14 TOTAL		**2 070.6**	**2 555.8**	**3 123.6**	**3 161.5**	**2 113.0**	**1 469.6**	**1 038.7**	**792.8**	**724.1**	**724.4**	**17 774.1**
ELECTRIC CAPITAL TOTAL		**2 022.6**	**2 490.9**	**3 073.1**	**3 125.2**	**2 078.3**	**1 431.5**	**998.8**	**750.8**	**679.4**	**681.0**	**17 331.7**
GAS CAPITAL TOTAL		**48.0**	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	-	-	-	-	-	-	-	-	-	-	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	-	-	-	-	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	-	-	-	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	-	-	-	-	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	-	-	-	-	-	-	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	-	-	-	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	0.6	2.6	19.1	45.3	67.6
Gillam Redevelopment and Expansion Program (GREP)	266.5	24.4	26.3	4.2	-	-	-	-	-	-	-	266.5
Bipole III - Transmission Line	1 655.4	-	-	-	-	-	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	-	-	-	-	-	-	-	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	-	-	-	-	-	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	-	-	-	-	-	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	-	-	-	-	-	-	-	-	-	-	348.0
Demand Side Management	NA	47.5	48.3	47.2	47.2	48.3	50.2	52.2	54.4	56.6	58.9	1 186.9
Generating Station Improvements & Upgrades	NA	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	453.2
Target Adjustment (Cost Flow)	NA	0.2	(0.3)	1.4	1.8	1.2	1.1	(0.6)	(0.6)	(3.0)	(8.5)	(19.4)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**107.8**	**110.7**	**97.8**	**81.3**	**70.5**	**60.7**	**66.5**	**71.6**	**98.4**	**175.0**	**12 611.1**

CAPITAL EXPENDITURE FORECAST (CEF14)

(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	-	115.9
Slave Falls Major Overhauls	126.1	20.1	21.3	20.9	0.9	-	-	-	-	-	-	126.1
Pointe du Bois GS Rehabilitation	182.9	-	-	-	-	-	-	-	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	-	-	-	-	50.4
Base Capital	NA	119.9	103.0	106.0	127.5	153.4	112.3	164.3	163.5	167.4	170.8	2 290.6
Total	**NA**	**142.9**	**145.7**	**148.7**	**151.6**	**154.7**	**157.8**	**160.9**	**164.1**	**167.4**	**170.8**	**2 900.6**
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	-	-	-	-	-	-	233.7
Base Capital	NA	153.0	156.1	159.2	162.4	165.6	168.9	172.3	175.7	179.3	182.8	2 452.3
Total	**NA**	**153.0**	**156.1**	**159.2**	**162.4**	**165.6**	**168.9**	**172.3**	**175.7**	**179.3**	**182.8**	**3 025.3**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	-	-	-	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	-	-	-	-	-	-	-	-	-	-	62.0
Base Capital	NA	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	305.3	4 773.2
Total	NA	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	305.3	5 019.6
Customer Care & Energy Conservation	NA	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.5	4.6	81.0
Human Resources & Corporate Services	NA	59.5	60.7	61.9	63.2	64.4	65.7	67.0	68.4	69.8	71.1	1 248.6
Finance & Regulatory	NA	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	4.9
		621.1	624.5	637.3	648.6	674.7	665.0	703.5	710.5	723.8	734.9	12 279.9
Gas												
Customer Service & Distribution	NA	33.7	33.5	34.0	34.7	36.6	34.1	38.2	39.3	40.2	41.0	664.1
Customer Care & Energy Conservation	NA	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.2	6.3	6.4	106.8
Gas Demand Side Management	NA	9.6	9.8	10.0	5.7	5.7	5.8	5.8	5.9	6.0	6.1	165.9
		48.7	48.7	49.6	46.1	48.1	45.8	50.1	51.4	52.4	53.5	936.8
Major & Base Capital Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		669.8	673.2	686.9	694.7	722.8	710.8	753.6	761.9	776.3	788.4	13 341.7
CONSOLIDATED CEF14 TOTAL		777.6	783.9	784.7	776.0	793.3	771.5	820.1	833.5	874.7	963.4	25 952.9
ELECTRIC CAPITAL TOTAL		728.9	735.1	735.1	729.9	745.3	725.7	770.0	782.2	822.2	910.0	25 016.1
GAS CAPITAL TOTAL		48.7	48.7	49.6	46.1	48.1	45.8	50.1	51.4	52.4	53.5	936.8

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AD FOR

Bipole III Project
TRANSMISSION LINE
Addendum Number 07a

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/01

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,259,915,000
REVISED BUDGET $: (Total Net Cost)	$1,655,371,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.1.1

W.B.S. NUMBERs: P:04218, P:04221, P:10155, P:14518, P:18414, P:20255, P:23817

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised estimate for increased length to 1341 km, construction cost increases, and inclusion of contingency.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **TRANSMISSION LINE**

Recommendation (This section is required for all Addendums).
Increase the budget by $395 million for the Transmission Line components of the Bipole III Project, to a revised total of $1,655 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:

- Design and construction of a western-routed 500kV HVdc transmission line from the Keewatinohk (Keewatinoow) Converter Station to the Riel Converter Station.
- Property acquisition and/or easements for the 500kV HVdc transmission line.
- Design and construction of the Bipole III Communications transport system.
- Licensing and environmental assessment for the overall Bipole III complex (i.e., including the 2000 MW converters and AC collector system).

Changes to scope include: revised line length of final approved route, issued Licence & Conditions, revised landowner compensation strategy and policy, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based on a preferred routing of the line prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, approved finalized route and right-of-way width, as well as up-to-date market information. Also since the last estimate, the project licence and permits were received later than planned, resulting in 1.5 lost winter seasons of 5 total planned. The estimate is based on the need for at least 4 more winter seasons to construct the transmission line and change to project in-service of July 2018.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for market uncertainty risk for transmission line construction work.

<u>P50 Estimate:</u>

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $363 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Changes to the finalized route (increased length, additional towers and increased right-of-way width)
- Updated land acquisition costs
- Recommended contingency of $110M (increase of $61M) to address remaining uncertainty. See

Background (This section is be filled out only if there is information relevant to the recommendation).

Risk Analysis section.

Reserves:
A Management Reserve has been established to address significant risks related to bidding market and pricing uncertainty for Transmission Line construction work (increase of $100M). See Risk Analysis section.

In-Service Costs:
The overall increase to the in-service cost of the project is $395M (31%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

Additionally, this portion of the Bipole III Project includes a recommended Management Reserve of $100M associated with bidding market and pricing uncertainty for Transmission Line construction work. This remains the greatest area of uncertainty for Bipole III and the potential cost variation associated with this risk is best addressed through the inclusion of Management Reserve funds.

An additional, significant area of uncertainty is the potential impacts to schedule due to further delays in acquisition of private lands. A Management Reserve for this risk has not been recommended as part of the project budget. However, there will be cost impacts to the project should the risk occur.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 24,613	$ 24,613	$ -
2010/11	$ 16,118	$ 19,002	$ 2,884
2011/12	$ 24,830	$ 18,350	$ (6,480)
2012/13	$ 59,866	$ 25,091	$ (34,775)
2013/14	$ 162,043	$ 54,276	$ (107,767)
2014/15	$ 298,935	$ 203,458	$ (95,477)
2015/16	$ 318,454	$ 360,455	$ 42,001
2016/17	$ 234,575	$ 381,047	$ 146,472
2017/18	$ 120,055	$ 493,821	$ 373,766
2018/19	$ 426	$ 75,257	$ 74,831
Total	$ 1,259,915	$ 1,655,371	$ 395,456

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION A FOR

Bipole III Project
CONVERTER STATIONS
Addendum Number 07b

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$1,828,532,000
REVISED BUDGET $: (Total Net Cost)	$2,675,083,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION:	BIPOLE III PROJECT
I.M. NODE NUMBER:	1.5.2.1.2.1
W.B.S. NUMBERs:	P:14363, P:14364, P:15533, P:15540, P:15541, P:15544, P:21082, P:23788, P:23837
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	Alastair Fogg / Adele Poulin
DATE PREPARED:	2014 09 24
REPORT NUMBER:	
FILE NUMBER (Optional):	

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06a	2011 03 31	Revised Converter Stations estimate, including assumption of VSC technology for HVdc	R.M. Elder	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **CONVERTER STATIONS**

Recommendation (This section is required for all Addendums).
Increase the budget by $ 846.5 million for the Converter Station components of the Bipole Project, to a revised total of $2,675 and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III complex includes the following major components:

- Design and construction 2300 MW Riel Converter Station and 230 kV AC Switchyard.
- Design and construction 2300 MW Keewatinohk (Keewatinoow) Converter Station and 230 kV AC Switchyard.
- Property acquisition and/or easements for the Riel and Keewatinohk Converter Stations.

Changes to scope include: Selection of LCC HVdc technology requiring the inclusion of Synchronous Condensers, increased Bipole III rating to 2300 MW, and revised project in-service date of July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2010, based largely on historical and budgetary pricing from vendors as well as an assumption of VSC technology for the HVdc Converter and therefore no requirement for synchronous condensers.

The revised estimate is based on LCC HVdc technology as this was the technology bid by all vendors and incorporates the bid pricing received. The selection of LCC technology has resulted in synchronous condensers being included in the revised estimate. Additionally, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised estimate. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>
Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in an increase of $649 million to the P50 Estimate as a result of the following:

- Incorporation of contract costs for the Keewatinohk 230kV AC Switchyard, Keewatinohk Site Development, Keewatinohk Camp and Keewatinohk Camp Services
- Incorporation of bid price for the Keewatinohk and Riel HVdc Converter Equipment contract
- Inclusion of Synchronous Condensers in the scope of work as a result of LCC technology for the HVdc equipment
- Incorporation of allocated portion of actual costs for Riel Sectionalization project
- Incorporation of updated costs for the Riel 230kV AC Switchyard Expansion

Background (This section is be filled out only if there is information relevant to the recommendation).
• Recommended contingency of $119.6M (decrease of $16M) to address remaining uncertainty. Reserves: No Management Reserve for the Converter Stations component of the project is recommended to include in the estimate at this time. In-Service Costs: The overall increase to the in-service cost of the project is $846.5 (46%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date, and addition of the Management Reserve. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).
A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system). The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
N/A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).
The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty. Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 30,423	$ 30,423	$ -
2010/11	$ 46,255	$ 28,069	$ (18,186)
2011/12	$ 59,696	$ 36,417	$ (23,279)
2012/13	$ 148,883	$ 79,718	$ (69,165)
2013/14	$ 300,258	$ 144,153	$ (156,105)
2014/15	$ 290,185	$ 221,051	$ (69,134)
2015/16	$ 294,281	$ 580,792	$ 286,511
2016/17	$ 308,460	$ 828,733	$ 520,273
2017/18	$ 347,692	$ 507,689	$ 159,997
2018/19	$ 2,399	$ 195,085	$ 192,686
2019/20	$ -	$ 18,432	$ 18,432
2020/21	$ -	$ 4,520	$ 4,520
Total	$ 1,828,532	$ 2,675,083	$ 846,551

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.3.1 Bipole III Project – Collector Lines
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AI FOR

Bipole III Project
COLLECTOR LINES
Addendum Number 07c

REVIEWED BY:
(Owning Dept Manager)
Adele Poulin 2014/10/01
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

[signature] 2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: [signature] 2014/10/02

Business Unit V.P.: [signature] 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$191,438,000
REVISED BUDGET $: (Total Net Cost)	$260,150,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.3.1

W.B.S. NUMBERs: P:15534-P:15537, P:15542, P:15543, P:15696, P:15697, P:18260, P:18261, P:20790, P:21201, P:23816

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 24

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ YES ☐ NO

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
06c	2011 03 31	Revised estimates for increase to five collector lines, two electrode lines, include construction power and sectionalization of R49R and all related property.	A.A. Poulin / P. Wang	Executive Committee (Minute #1348.02)
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **COLLECTOR LINES**

Recommendation (This section is required for all Addendums).
Increase the budget by $68.7 million for the Collector Lines components of the Bipole III Project, to a revised total of $260.2 million and a revised in-service date of July, 2018.

Project Scope (This section is be filled out only if there is a change to the scope).

The scope of this portion of the Bipole III Project includes the following major components:

- Design and construction of three permanent and two temporary 230 KV collector lines for the Keewatinohk (Keewatinoow) Converter Station.
- Construction power substation, 138 KV line, microwave tower, and distribution feeders for the Keewatinohk Converter Station.
- Design and construction of the Riel and Keewatinohk electrode lines.
- Sectionalization of 230 KV transmission line R49R at Riel and associated modifications at Ridgeway and Rosser stations.
- Property acquisition and/or easements for the above components.
- Design and construction of a new bay and modifications at existing Long Spruce 230 KV AC switchyard for the new collector line to Keewatinohk Converter Station.
- Design and construction of a new bay and modifications at existing Henday 230 KV AC switchyard for the four new collector lines to Keewatinoow Converter Station.
- Design and construction of breaker replacements at existing stations (Ridgeway, Rosser, and McPhillips) for Bipole III.

Changes to scope include: the issued Licence & Conditions, double circuit requirement for one collector line, increased reliability design for electrode lines, updated assumptions for direct negotiated clearing and construction contracts, inclusion of Long Spruce and Henday 230 KV station expansions/modifications, inclusion of breaker replacements, and revised schedule and project in-service date to July 2018.

Background (This section is be filled out only if there is information relevant to the recommendation).

The last project re-estimate was completed in 2009/10, based on conceptual scope of collector line components, prior to issuance of the Project Licence.

The revised estimate incorporates a more detailed scope based on an issued environment act licence, increased scope (new items in this component), as well as up-to-date market information. The estimate is based on a project in-service of July 2018, which is required to complete the HVdc Converters installation.

The recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level.

<u>P50 Estimate:</u>

Since the last estimate was developed in 2010 it was necessary to bring the estimate to 2014$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. In addition, new items were included in the current scope for this component.

Background (This section is be filled out only if there is information relevant to the recommendation).

This resulted in an increase of $83 million to the P50 Estimate as a result of the following:

- Incorporation of Environment Act Licence conditions and monitoring requirements
- Change to include a double circuit requirement for the Keewatinoow to Long Spruce AC collector line
- Incorporation of increased reliability design for both electrode lines
- Change to assume Clearing, 230kV AC transmission line construction and Construction Power contracts as Direct Negotiated Contracts (DNCs)
- Inclusion of new items – Long Spruce and Henday 230 KV station expansions/modifications and breaker replacements projects
- Recommended contingency of $18M (increase of $800K) for this component, to address remaining uncertainty. See Risk Analysis section.

Reserves:
No Management Reserve for the Collector Lines components is recommended to include in the estimate at this time. See Risk Analysis section.

In-Service Costs:
The overall increase to the in-service cost of the project for this component is $68 M (36%). This increase to the in-service cost is due to the increases in the P50 base estimate, the change to the project in-service date and increase in the recommended contingency. These increases are offset by reduced interest and escalation costs.

Justification (This section is required for all addendums).

A third 500kV HVdc transmission line with converter stations will provide for increased reliability to the Manitoba Hydro system, due to the critical risk to the Province and the Corporation of a Dorsey Converter Station outage or an Interlake (Bipole I and II) corridor outage. It will also provide an increase in southern power due to reduced line losses on the existing Bipoles I and II (approximately 76MW in normal steady state operation prior to the addition of new generation into the northern collector system).

The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation associated with Keeyask and Conawapa can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage. The increased rating limits the amount of future upgrades and equipment replacement needed on the Bipole III HVdc system to accommodate future Conawapa generation.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**
No change.	

Other Alternatives Considered	NPV Benefits/(Costs)
N/A	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

The risk & contingency methodology outlined at the NFAT for Keeyask & Conawapa Projects has been applied to the revised Bipole III Project estimate. The estimate includes a recommended project contingency at a P50 confidence level to address remaining areas of uncertainty.

Inclusion of a Management Reserve for this portion of the Bipole III complex is not considered necessary at this time.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 0	$ 0	$ -
2010/11	$ 2,121	$ 386	$ (1,735)
2011/12	$ 19,917	$ 2,075	$ (17,842)
2012/13	$ 52,709	$ 4,394	$ (48,315)
2013/14	$ 30,141	$ 26,265	$ (3,876)
2014/15	$ 30,927	$ 58,432	$ 27,505
2015/16	$ 34,255	$ 75,516	$ 41,261
2016/17	$ 13,549	$ 51,722	$ 38,173
2017/18	$ 7,819	$ 36,708	$ 28,889
2018/19	$ -	$ 4,653	$ 4,653
Total	$ 191,438	$ 260,150	$ 68,711

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.7.1 Bipole III Project – Community Development Initiative

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

1. System Planning Department Report on Bipole III Rating, 2012 11 02
2. System Planning Department Report on Integrated Transmission Plan for Keeyask and Conawapa Generation, 2012 07 06

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1503.02

DATE: 2014 10 21
Financial Planning

CAPITAL PROJECT JUSTIFICATION AI FOR

Bipole III Project
COMMUNITY DEVELOPMENT INITIATIVE
Addendum Number 07d

REVIEWED BY:
(Owning Dept Manager)
A. Fogg 2014/10/02

NOTED BY:
(if applicable)

Coordinating Division:
2014/10/14

Constructing Division:

Financial Department:
(if over $1 million)
2014/10/01

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: 2014/10/02

Business Unit V.P.: 7 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$60,782,000
REVISED BUDGET $: (Total Net Cost)	$61,954,000
START DATE: (1st Cost Flow)	2014 03
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Last Major In-service Date)	2018 07
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	N.A.
INVESTMENT REASONS: (Optional)	

OWNING DIVISION: BIPOLE III PROJECT

I.M. NODE NUMBER: 1.5.2.1.7.1

W.B.S. NUMBERs: P:21948

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: Alastair Fogg / Adele Poulin

DATE PREPARED: 2014 09 26

REPORT NUMBER:

FILE NUMBER (Optional):

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☐ System Supply
- ☒ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

-	2001 06 13	Original CPJ	E.R. Kristjanson	Executive Committee (Minute #1453.03)
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Project – **COMMUNITY DEVELOPMENT INITIATIVE (CDI)**

Recommendation (This section is required for all Addendums).
Increase the budget by $1.2 million for the Bipole III Community Development Initiative ("CDI") fund, that was approved by the Manitoba Hydro-Electric Board in May 2010, to a revised total of $62.0 million

Project Scope (This section is be filled out only if there is a change to the scope).
Community Development Initiative ("CDI") fund for Manitoba Hydro to provide benefits to communities in vicinity of the Bipole III Project

Background (This section is be filled out only if there is information relevant to the recommendation).

The Manitoba Hydro-Electric Board approved the establishment of a Bipole III Community Development Initiative ("CDI"), valued at up to $6 million a year, for Manitoba Hydro to provide benefits to communities in the vicinity of the Bipole III project facilities (May 20, 2010, minute 808-10-03).

Following this approval, the Bipole III Preliminary Preferred Route became known and was released publicly in July 2010. From the time of Board approval, a multi-business unit CDI Working Group continued to meet to refine the CDI approach, in light of the preliminary preferred route, and to develop related communications material. Following feedback regarding the CDI, there was consensus that the refinements described in the recommendation be implemented, which include the following:

a) That CDI payments be provided for a 10 year period, with the possibility of program renewal at the end of the 10 year period;
b) That CDI payments begin upon receipt of the Bipole III regulatory approvals;
c) That the boundary for communities whose eligibility is based on proximity to the line be limited to 40 km;
d) That the eligibility requirements for incorporated towns and villages be such that a town or village must be located within a municipality traversed by the line and be located within 40 km of the line; and
e) That the CDI payments to communities be adjusted annually with the change in inflation.

Justification (This section is required for all addendums).
The CDI program remains inclusive of a variety of interests; is required as part of Bipole III; and will be an effective means of promoting community support for hosting the Bipole III project facilities

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	NPV Benefits/(Costs)
No Change	

Other Alternatives Considered	NPV Benefits/(Costs)
N.A.	

Risk Analysis – (This section is be filled out only if there is a change to the project risk).

No Change.

Total Budget – (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ -	$ -	$ -
2013/14	$ 53,937	$ 53,863	$ (73)
2014/15	$ 2,157	$ 2,291	$ 134
2015/16	$ 1,979	$ 1,979	$ -
2016/17	$ 1,787	$ 1,787	$ -
2017/18	$ 922	$ 1,581	$ 659
2018/19	$ -	$ 453	$ 453
Total	$ 60,782	$ 61,954	$ 1,172

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

The schedule has been updated for the proposed change to in-service date of July 2018.

Related Projects (This section is be filled out only if changed).

1.5.2.1.1.1 Bipole III Project – Transmission Line
1.5.2.1.2.1 Bipole III Project – Converter Stations
1.5.2.1.3.1 Bipole III Project – Collector Lines

1.1.2.3.62.1 Southern AC System Breaker Replacements

Reference Documents (This section is be filled out only if changed).

Identify any additional reference documents (relative to those already listed in the previous CPJ/Addendum) that support or provide background on this recommendation.

D1876(A)

April 5, 2011
PUB 19(A)

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CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

BIPOLE III WESTERN ROUTE 500kV HVDC TRANSMISSION LINE & 2000MW CONVERTERS
Addendum Number 06

REVIEWED BY:
(Owning Dept Mgr - Transmission)

(Owning Dept Mgr – Power Supply)

NOTED BY:
(if applicable)

Coordinating Div:

Constructing Div:

Financial:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$2,247,835,000
REVISED BUDGET $: (Total Net Cost)	$3,953,749,000
START DATE: (1st Cost Flow)	2001 06
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2017 10
REVISED ISD: (Indicate "Mult" if more than 1)	2017 10
RISK MATRIX/ BUSINESS CASE TIER:	Tier 2 (950 pts)
INVESTMENT REASON: (Category and % Split)	Operational Enhancement (60%) New/increased Gen. Delivery (20%) Capacity Enhancement (20%)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Mgr – Transmission:

Owning Div. Mgr – Power Supply:

Vice-President – Transmission: H. Tymofichuk 2009.09.10

Vice President – Power Supply: R.B. Adams 09 09 10

OWNING DIVISIONs:	Transmission Planning & Design New Generation Construction
I.M. NODE NUMBER:	1.5.2.1
W.B.S. NUMBERs:	P:04218, P:04221, P:10155, P:14363 P:14364, P:14518, P:15533 - P:15537, P:15540 – P15544, P:15696, P:15697
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	K.L. Kent (Complex Owner) A.A. Poulin (Complex Manager) H.S. Jhinger (Proj. Mgr, Converters)
DATE PREPARED:	2009 08 18
REPORT NUMBER:	

ADDENDUM NUMBER	DATE (yyyy mm dd)	REVISION	REVISED BY	APPROVED BY
05	2007 05 15	Revised western route placeholder. Increase costs due to Construction and material cost increases.	A.A. Poulin / J.B. Davies / K.L. Kent	MH Board of Directors (Minute #786-07-05)
04	2005 06 23	Western route placeholder. Defer the in-service date by five years from 2012 10 to 2017 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1090.06)
03	2004 04 06	Defer the in-service date by two years from 2010 10 to 2012 10.	J.B. Davies / K.L. Kent	Executive Committee (Minute #1030.05)
02	2003 11 12	Defer $2,462,000 worth of budget requirements from 2003/04 to future years.	C.A. Nieuwenburg	Executive Committee (Minute #999.05)
01	2003 05 08	Change northern termination from Radisson to Henday, increasing length by 20 km and costs by $8,245K.	J.B. Davies / K.L. Kent	Executive Committee (Minute #993.03)
-	2001 06 13	Original CPJ	J.B. Davies / K.L. Kent	Executive Committee (Minute #900.11)

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Bipole III Western Route 500kV HVdc Transmission Line & 2000MW Converters

Recommendation (This section is required for all Addendums).

Increase the budget for the Bipole III complex by $1706 million to a revised total of $3954 million, in order to incorporate the following:

- review of estimates for all components of the complex (total increase of $739 million to the base estimate, 2009$),
- inclusion of contingency for all components of the complex (total increase of $525 million to the base estimate, 2009$), and
- the resultant changes to interest and escalation (increase of $442 million).

Project Scope (This section is be filled out only if there is a change to the scope).

No change to the high-level concept at this time. Potential future changes to scope (cost and schedule) that may be forthcoming in a subsequent CPJ Addendum (i.e., are not part of this submission) are as follows:

- Changes to the existing transmission network or at existing generation facilities that may be necessary as a result of the Bipole III transmission line and converters being added to the system.
- Changes that may be necessary for an HVdc transmission line and converters rated at 2500MW.
- Application of Transmission Development Fund (TDF) and/or Adverse Effects policies that may be recommended for the Bipole III complex.

Background (This section is be filled out only if there is information relevant to the recommendation).

CPJ Addendum #04, submitted in April 2005, was the first introduction to the Capital Expenditure Forecast of a western-routed 500kV HVdc transmission line with 2000MW of converters. The budget submitted with CPJ Addendum #04 was a placeholder only, pending completion of studies by System Planning, and was based on a 2001 estimate prepared by Teshmont Consultants.

CPJ Addendum #05, submitted in May 2007, addressed an increase of 45km to the length of the transmission line, as well as increases being experienced in transmission line material and construction costs due to market prices. The cost of licensing, property and converters were not updated at that time, nor was contingency identified in that estimate.

This CPJ Addendum #06 covers re-estimates that have been prepared since either the 2001 Teshmont report or the May 2007 CPJ Addendum, for all components of the Bipole III complex. These re-estimates result in an increase of $739 million to the base estimate, detailed as follows (all amounts are in 2009$).

TRANSMISSION-RELATED ITEMS (total increase of $142 million to base estimate):

a) <u>500kV dc Transmission Line</u>
The base estimate for the transmission line has increased by $72 million due to a design change from double to triple conductor, in order to lower the surface field gradient to accepted worldwide practices and thus minimize flashovers, and by $25 million due to the application of the Transmission Line Agreement (TLA), or unionization of labour.

Background (This section is be filled out only if there is information relevant to the recommendation).

b) Northern 230kV Collector Lines
Reflects increases since 2001 to both construction material and labour costs ($23 million). Also reflects an increase of 39km to the overall length of transmission line construction required ($9 million). In addition, the line from Limestone to Conawapa, previously assumed to be established with the construction power for the Conawapa G.S, is now required first for construction power of the Northern Converter Station ($9 million).

c) Licensing & Environmental Assessment
Costs have increased by $2 million due to more comprehensive aboriginal and community consultations.

d) Sectionalize 230kV Transmission Line R49R at Riel
This is a new item, estimated at $2 million. R49R sectionalization is required to accommodate and reliably transmit a 2000MW Bipole III at Riel. This had been recommenced with the Riel Sectionalization project but was deferred to coincide with Bipole III converters.

In addition to the above, the risk assessment yielded a contingency estimate of $143 million (see the Risk Analysis section for details). These changes, along with an increase of $57 million for interest and escalation, make the total net increase equal to $343 million and the revised total net cost equal to $1477 million, for the transmission-related portion of the complex.

CONVERTER-RELATED ITEMS (total increase of $596 million to base estimate):

e) Riel Converter Station
Converter and HVdc equipment costs remain relatively unchanged; however, the costs for synchronous condensers have more than doubled. Studies have also recommended the addition of a fourth synchronous condenser for the 2000MW Bipole ($193 million combined increase). Other increases to the base estimate include: higher construction management, project management and engineering costs, which were not fully considered in the 2001 placeholder ($49 million); and increase in site size, development and infrastructure costs driven by safety and maintenance requirements, as well as additional facilities for fast drain and oil spill containment systems ($29 million).

f) Northern Converter Station at Conawapa
Converter and HVdc equipment costs remain relatively unchanged. Changes to the base cost are as a result of: inclusion of the construction camp previously assumed to be built and covered by the Conawapa G.S. Project ($38 million); higher construction management, project management and engineering costs not fully considered in the 2001 placeholder ($61 million), and site size increase of 2.2 times that assumed in 2001 and the associated increase in site development and infrastructure costs driven by safety and maintenance requirements, as well as additional facilities for fast drain and oil spill containment systems ($54 million).

g) Riel Site Development for Converters & 230kV Switchyard
Part of the switchyard will be established under a separate project, Riel Sectionalization; however, the concept was developed to more easily accommodate the future HVdc requirements (5 bays and 12 breakers vs. just 3 bays and 9 breakers) and reconfiguration to accommodate a transfer bus scheme, therefore 50% of the equipment costs are included in this estimate ($33 million). An expansion of the 230kV switchyard is required with Bipole III to output the 2000MW, establishing 4 new bays and 11 breakers, and required terminations for HVdc equipment are included in the base estimate ($51

Background (This section is be filled out only if there is information relevant to the recommendation).

million). Half of the site development costs at Riel are included here as attributable to the Converter Station and 230 Switchyard, whereas the 2001 report did not have any site development costs (assumed it would be developed at Riel prior to Bipole III). Like the northern converter station, the site size at Riel has increased (approx. 2.6 times) due to maintenance and security requirements, changes to oil spill containment systems, and planning the layout to accommodate for future additions to the station (i.e. paralleling line and additional 500kV and 230kV AC lines). The associated site development and infrastructure costs have increased ($28 million).

h) Northern 230kV Switchyard
Estimate has increased by $25 million to accommodate the following scope changes: two temporary additional AC lines required to transmit a 2000MW Bipole in the interval when Bipole III is in service before Conawapa G.S. (due to the change in generation sequence), and three lines for future Gilliam Island addition, for a total of 8 bays and 32 breakers.

i) Property for the Riel Converter Station
Not previously included in the estimate. Includes $6 million worth of station site properties and $12 million worth of buffer properties, all purchased from private owners.

j) Construction Power Station for Northern Converter
This item was not previously included, as it had been assumed to be part of the construction of the Conawapa Generation Station. Due to a change in sequencing this complex will be the first to require construction power, and hence the estimated cost of $15 million is now part of this complex.

k) Electrode Lines and Stations
Other components not previously included that have now been estimated are for the electrode lines and stations for both the Northern and the Riel Converter Stations, for a total of $2 million.

In addition to the above, the risk assessment yielded a contingency estimate of $382 million (see the Risk Analysis section for details). These changes, along with an increase of $384 million for interest and escalation, make the total net increase equal to $1363 million and the revised total net cost equal to $2477 million, for the converter-related portion of the complex.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

On July 4th, 2001 a System Planning report entitled "Minimum Transmission Requirements for HVDC Bulk System Reliability" (SPD 01/7) was issued and subsequently approved. A major recommendation of that report was for a Bipole III transmission line routed east of Lake Winnipeg. Converter capacity to be connected to the line would be considered in subsequent studies.

At the request of the MHEB, System Planning examined reliability alternatives to an eastern routed Bipole III line. The report entitled "Manitoba HVDC Reliability Alternatives" (SPD 2006/11) was issued on October 4th, 2006, and concluded that Bipole III routed west of Lakes Winnipegosis and Manitoba with 2000 MW of converter capacity was the leading reliability alternative to an eastern routed line.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).

Based on the conclusions of this report, a recommendation was made by the Executive to the MHEB to proceed with Bipole III, routed west of Lakes Winnipegosis and Manitoba, and with 2000 MW of converter capacity.

Capital Investment Categorization:

Driver	Category	Sub-category	Split	Amount
Reliability-Outage Related	Operational Enhancement	New Asset Addition	60%	$2,372,250,000
Reliability-Load Related	Capacity Enhancement (for domestic load)	New Asset Addition	20%	$ 790,750,000
Reliability-Load Related	New/increased Generation Delivery (for domestic load)	New Asset Addition	20%	$ 790,750,000
				$3,953,750,000

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	%	**For current corporate rates see G911** **For clarification on hurdle rates, contact Economic Analysis Department**

Recommended Option	**NPV (= PV of BENEFITS - PV of COSTS)**
No change.	

Other Alternatives Considered	**NPV (= PV of BENEFITS - PV of COSTS)**
No change.	

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Contingency (total of $525 million in base 2009$):

The contingency estimate is based on risk assessments that were conducted to identify areas of uncertainty or potential fluctuation, and is detailed as follows:

TRANSMISSION-RELATED ITEMS (total contingency of $143 million or 15% of the base costs):

a) 500kV dc Transmission Line (total contingency = $116 million or 15% of the base costs)
- A potential change to the detailed route selection or line length of up to 10%, as the final route has not yet been determined ($87 million).
- Related to lack of geotechnical information, uncertainty with soil conditions calls for the purchase of extra foundation types to allow for flexibility during the tight construction window ($15 million).
- Potential premiums in association with maximizing aboriginal content ($10 million).
- Higher compensation to property owners for damages during construction, based on National Energy Board (NEB) compensation settlements recently experienced in Alberta ($4 million).

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

b) Licensing & Environmental Assessment (total contingency = $13 million or 21% of the base costs)
- Greatest risk for licensing is in the costs for aboriginal and community consultations ($9 million).
- Potential for even more extensive environmental monitoring and assessments, based on our experiences with the Wuskwatim project ($4 million).

c) Northern 230kV Collector Lines (total contingency = $10 million or 12 % of the base costs)
Design uncertainty and exact location of the northern converter station could increase the total line lengths assumed.

d) Property for 500kV dc Transmission Line (total contingency = $4 million or 18% of the base costs)
Potential increases in land values, by as much as 50%, based on the NEB compensation settlements recently experienced in Alberta. Note however that this risk estimate does not include any costs for expropriation of land and the associated legal expenses.

CONVERTER-RELATED ITEMS (total contingency of $382 million or 26% of the base costs):

e) Riel Converter Station (total contingency = $200 million or 39% of the base costs)
Based on a Range Estimating session, recommend contingency for equipment costs due to limited number of suppliers worldwide and variability on exchange rates ($100 million for converters and $100 million for synchronous condensers).

f) Northern Converter Station (total contingency = $135 million or 18% of the base costs)
Based on a Range Estimating session, recommend contingency for equipment costs due to limited number of suppliers worldwide and variability on exchange rates ($100 million for converters); and potential for higher costs associated with northern work ($35 million).

g) Riel Site Development for Converters & AC Switchyard (total contingency = $25 million or 19% of the base costs)
Final Design for Phase A of the Riel Switchyard won't be available from the engineer and procure contract until January 2010, while final design for Phase B is three to six years away. There is also uncertainty with line protection, cyber security, and building strength. Re-work is anticipated for site preparation, as construction will be started ahead of final design to protect against the risk of a wet summer delaying the construction progress.

h) Northern 230kV AC Switchyard (total contingency = $15 million or 31% of the base costs)
Based on a Range Estimating session, recommend contingency for potentially higher costs associated with northern work.

i) Construction Power Station for Northern Converter Station (total contingency = $4 million or 27% of the base costs)
Design and construction estimate are based on a conceptual Single Line Diagram (SLD) only; the site size and exact location of the Converter Station is not yet confirmed.

j) Northern and Riel Electrode Lines (total contingency = $3 million or 36% of the base costs)
The length of the lines is not certain, as Electrode sites have not yet been determined. Also provides for the use of steel towers if necessary (base estimate assumes wood).

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Management Reserve (total of $334 million in base 2009$):

Also identified during the risk assessment but not included in the contingency estimate at this time, are the management reserve items listed below. Though each of the components covered by this list has a contingency amount included within the project estimate, there is potential for further increases above those contingency amounts, for the following factors:

- Premium if basing the converters estimate on pricing received from the most experienced supplier ($102 million, high probability).
- Uncertainty on the northern interconnecting station modifications at Henday Converter Station and Long Spruce Generating Station, as the scope is not well defined at this time ($20 million, high probability).
- Allowance for greater requirement for engineering, project management and construction management on the Northern Converter Station and the Riel Converter Station projects ($14 million, high probability).
- Allowance for poor soil conditions during construction of the Northern Converter Station ($12 million, high probability)
- Market conditions for transmission line construction labour may increase costs by as much as 20% ($70 million, low probability).
- Market conditions for transmission-related materials or commodities (e.g., towers, hardware, conductor, insulators, foundations, communications equipment) may increase by 10-25% ($61 million, low probability).
- Increase to design, supply and install (construction) costs for the Northern 230kV AC Switchyard if a gas-insulated station (GIS) is chosen instead of an air-insulated station (AIS), due to unknown soil conditions ($55 million, low probability).

Some of the schedule-related risks associated with meeting an October 2017 in-service are as follows:

- The detailed route selection must be finalized by December 2010.
- An Environmental Licence must be received by September 2012.
- Certain activities will need to proceed in parallel with the environmental licensing process:
  - acquiring permits to work on crown lands,
  - purchase of some materials and/or purchase of extra towers and foundations types to accommodate unexpected conditions due to lack of geotechnical information,
  - temporary permits for site investigation activities (including field drilling) in order for design of foundations to be finalized and materials ordered for the construction start date.
- Completion of the northern portion of the Western route is based on having five winter seasons for access and construction. The southern portion of the Western route can be built year-round, however it is subject to more property and land access issues.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No change.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Previous CPJ / CPJ Addendum	This CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 7,613	$ 7,613	$ -
2007/08	$ 1,875	$ 1,955	$ 80
2008/09	$ 2,901	$ 17,878	$ 14,977
2009/10	$ 9,298	$ 33,037	$ 23,739
2010/11	$ 12,994	$ 80,542	$ 67,548
2011/12	$ 25,115	$ 110,970	$ 85,855
2012/13	$ 172,475	$ 271,913	$ 99,438
2013/14	$ 331,532	$ 671,609	$ 340,077
2014/15	$ 420,146	$ 691,071	$ 270,926
2015/16	$ 579,614	$ 823,189	$ 243,576
2016/17	$ 535,141	$ 866,711	$ 331,570
2017/18	$ 145,948	$ 375,335	$ 229,387
2018/19	$ 3,184	$ 1,926	$ (1,258)
Total	$ 2,247,835	$ 3,953,749	$ 1,705,914

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

No change.

BIPOLE III
CAPITAL COST ESTIMATES
($ Thousands)

	CEF10-1 (Appendix 82)	2009 CPJ Addendum (Not Approved)	New March 31, 2011 Cost
Transmission Line			
- Base Cost	$737,255	$873,154	$889,378
- Contingency	-	133,279	49,353
- Interest & Escalation	344,668	348,203	321,184
Total	$1,081,923	$1,354,636	$1,259,915
Converters			
- Base Cost	$751,744	$1,445,059	$1,225,970
- Contingency	-	375,000	138,926
- Interest & Escalation	352,452	610,252	463,636
Total	$1,104,196	$2,430,311	$1,828,532
Collector Lines			
- Base Cost	$42,016	$108,219	$115,238
- Contingency	-	17,203	17,203
- Interest & Escalation	19,699	43,380	58,996
Total	$61,715	$168,802	$191,437
TOTAL	**$2,247,834**	**$3,953,749**	**$3,279,884**
$ Base Year	($2007)	($2009)	($2010)

that explains the -- the chart more so. One (1) question, maybe Mr. Bowen. In terms of the Bipole costs, we've seen that last update in the CEF was -- and I didn't look at the new one, quite frankly -- was 2010. And it came in at about $3.2 billion.

Have I got that number correct?

MR. DAVE BOWEN: I don't have the number in front of me. Sounds in -- like it's in the right ballpark.

MR. BOB PETERS: Okay. But just asking: Has there been any update on the Bipole III cost?

MR. DAVE BOWEN: I'm looking to Patti here. I don't -- I don't think the Bipole III is part of this process.

MR. BOB PETERS: Manitoba Hydro wants to recover the costs of Bipole III, does it, Mr. Wojczynski, from Manitoba ratepayers?

MR. ED WOJCZYNSKI: Yes.

MR. BOB PETERS: And so the costs of Bipole III will eventually hit the operating statement, which will be brought before the Public Utilities Board as part of a rate increase?

MR. ED WOJCZYNSKI: Yes.

MR. BOB PETERS: And in fact, in the

last GRA, in Order 43/'13, the Public Utilities Board also earmarked or put into a deferral account a certain amount of monies on account of Bipole III costs that will come down for consumers?

MS. PATTI RAMAGE: Mr. Peters, this is the wrong panel to be putting that information to.

MR. BOB PETERS: Well, the -- is this not the right panel, Ms. -- Ms. Ramage, to ask whether the Bipole III cost has changed?

MS. PATTI RAMAGE: First --

MR. ED WOJCZYNSKI: There is no updated cost estimate for Bipole III.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Thank you, sir.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Bowen, still with you, sir. On Tab 109 of Manitoba Hydro Exhibit 95 you had talked about the project execution.

And I believe at the time you talked to the panel about this, you also were able to disclose on the public record the successful general civil contract providers?

Section:	Tab 4, Appendix 4.1	Page No.:	PUB/MH I-20(e)
Topic:	Capital Expenditure Forecast		
Subtopic:	Bipole III Project Costs		
Issue:	Cost Escalations and Scope Change		

PREAMBLE TO IR (IF ANY):

The provided 2010 CPJ calculations of Bipole III budget estimates breakdowns are as follows:

– licensing & properties	$ 188M
– transmission line	1,210M
– Keewatinow converter station	948M
– Keewatinow AC collector system	294M
– Riel converter station	1,467M
Total for Bipole III	$4,107M

QUESTION:

a) Provide a similar line item estimate of MH's 2014 budget estimate of $4.65B.

b) Explain the changes in budget line items going from 2010 to 2014.

c) Identify any specific scope changes any cost implications.

RATIONALE FOR QUESTION:

MH's budget increase for Bipole III from $3.27B to $4.65B needs a detailed explanation.

RESPONSE:

a) The following table outlines the Bipole III 2014 Control Budget in the requested format:

Estimate Item	**2014 Bipole III Control Budget** *(in Millions $)*
Licensing & Properties	$255.8
Transmission Line	$1,422.7
Keewatinohk Converter Station	$1,476.9
AC Collector System	$255.4
Riel Converter Station (*including Riel Expansion*)	$1,179.8
Community Development Initiative (CDI)	$61.9
Total Cost for Bipole III	**$4,652.5**

b) Manitoba Hydro provided the CPJ's which have been approved over the last 4 years in its response to PUB/MH I-20e. Please refer to the response provided in PUB/MH I-20a for the explanations on the increase to the Bipole III budget from the $3,279.8 billion amount included in CEF10-2, CEF11-2, and CEF 12 to the updated cost in CEF14 of $4,652.5.

c) Please refer to PUB/MH-II-13a-d for explanation of the change to the HVDC Converter capacity. There are no other scope changes to note.

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I-17 c
Topic:	Capital Expenditures		
Subtopic:	Construction Work in Progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

MH commissioned Rashwan Consultant to review Manitoba Hydro's cost estimates of the Bipole III Converter Stations. The Costs of Bipole III have changed since the study was undertaken in 2011.

QUESTION:

Please file a copy of the Rashwan Consultant report.

RATIONALE FOR QUESTION:

To understand the reasons for the increase in capital costs for Bipole III.

RESPONSE:

The information requested contains commercially sensitivity information and has been filed in confidence with the PUB.

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I-17 c
Topic:	Capital Expenditures		
Subtopic:	Construction Work in Progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

MH commissioned Rashwan Consultant to review Manitoba Hydro's cost estimates of the Bipole III Converter Stations. The Costs of Bipole III have changed since the study was undertaken in 2011.

QUESTION:

File MH's response to the findings in the report.

RATIONALE FOR QUESTION:

To understand the reasons for the increase in capital costs for Bipole III.

RESPONSE:

The Key assumptions/findings in the Rashwan report that resulted in the recommended project cost were as follows:

1. The use of historical project costs to form the basis of the Converter Stations Estimate
2. Assumption of an appropriate project contingency at 7.9%

Since the report was filed in 2011, a complete re-estimate has been undertaken on the Bipole III project using Manitoba Hydro's major capital project cost estimating process that was outlined during the NFAT process. During this process the above key assumptions that formed the basis for the Rashwan report were addressed as follows:

1. **Historical Project Costs vs. Awarded Contract Amounts:**

The findings and recommended project cost in the Rashwan report were largely based on historical costs for similar HVDC installation across the world (i.e. not limited to North America). While the use of historical costs is an accepted estimating approach, since 2011 there has been a notable escalation in construction costs across Canada which has impacted the reasonableness of relying on previous historical costs.

The Converter Stations portion of the 2014 Bipole III estimate is largely based on awarded contract values rather than estimated contract amounts based on historical costs. Specifically, the awarded, fixed price contract amount for the HVDC Converter Equipment, the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard contracts have all been incorporated into the revised 2014 Control Budget. Additionally, the estimated values of any major contracts still to be awarded were updated based on these awarded contract amounts.

2. **The Amount of Project Contingency Included:**

The Rashwan report recommended a project contingency of 7.9% be applied on Bipole III.

Since the Rashwan report was submitted in 2011, Manitoba Hydro has established a detailed risk & contingency process as part of its major capital project cost estimating process. As outlined during the NFAT, and confirmed by Knight Piesold, this risk & contingency process follows industry recognized best practices and is facilitated by a 3rd party risk & contingency expert.

A complete risk and contingency review was conducted as part of establishing the revised 2014 Bipole III Control Budget. The same risk identification and contingency development process applied on the Keeyask project (as presented during the NFAT process) was applied to the Bipole III Project. From this exercise, a revised P50 contingency and Management Reserve fund for Bipole III were developed and included as part of the Control Budget.

Section:	Tab 4, Appendix 4.1	**Page No.:**	PUB/MH I-20
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Cost escalation		

PREAMBLE TO IR (IF ANY):

Additional contracts may have been finalized since the last Bipole III cost estimate was provided to the Board.

QUESTION:

a) Provide a breakdown and status of concluded and remaining Bipole III transmission line, collector and converter station procurement and installation contracts in a similar manner to PUB/MH-I-24(a). In addition to filing a redacted version on the public record, file an unredacted version in confidence that indicates the total dollar value of each of the contracts.

b) Provide the detailed cost estimate calculations that support the CEF12 budget estimate of $3.28B and the CEF14 budget estimate of $4.65B.

RATIONALE FOR QUESTION:

The Capital Project Justification (CPJ) sheets lack component cost details.

RESPONSE:

a) The following is a breakdown of the major contracts for Bipole III. Information on contract dollar values is being filed in confidence with the PUB.

Contract	Status	Award Value *(millions $)*	Type	Escalation
Riel & Keewatinohk HVDC Converters & Associated Equipment	Awarded. Work Started		Fixed Price	Escalation clause in contract
Riel Synchronous Condensers	Final Negotiations		Fixed Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N2 & S2)	RFP to be Issued		Unit Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N3 & S1)	RFP to be Issued		Unit Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N1 & C2)	RFP to be issued		Unit Price	Escalation clause in contract
Bipole III - 500kV Transmission Line Construction (segments N4 & C1)	RFP to be issued		Unit Price	Escalation clause in contract
Keewatinohk 230kV AC Switchyard	Awarded. Work Started		Fixed Price	Escalation clause in contract
Keewatinohk Construction Camp	Awarded. Work Started		Fixed Price	No Escalation
Bipole III - 500kV Transmission Line Anchors & Foundations (segments N4, C1 & C2)	RFP to be issued		Unit Price	Escalation clause in contract
Keewatinohk Camp Catering, Maintenance, Janitorial & Security	Awarded. Work Started		Unit Price	Escalation clause in contract
Keewatinohk Converter Station Civil Site Development	Awarded. Work Started		Unit Price	Escalation clause in contract
Supply of Bipole III Conductor	Awarded. Work Started		Fixed Price	Escalation clause in contract
Construction of Keewatinohk AC Collector Lines	Awarded. Work Started		Fixed Price	No Escalation
Supply of Bipole III 500kV Transmission Line Steel Towers	Awarded. Work Started		Fixed Price	Escalation clause in contract

For each contract, specific escalation clauses apply which will cause either an increase or a decrease in the actual cost of the work depending on the commodity or labour indices that apply. These indices are driven by the marketplace or specified in the applicable labour agreement. In all cases, contingency has been allocated to address escalation.

b) The CEF 14 budget was developed following the major capital project cost estimating process, which was discussed and reviewed during the NFAT. The estimate development process is a structured approach that builds the estimate from the bottom-up. For the CEF 14 budget a detailed revision of estimate assumptions, incorporation of current market conditions and inclusion of actual bid prices received to-date on the project was conducted.

A more detailed breakdown of the cost items for Bipole III is commercially sensitive and is being filed in confidence with the PUB.

Section:	Tab 4, Appendix 4.1	Page No.:	PUB/MH I-20(e) Attachment 5
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Cost escalation		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro considered increasing Bipole III capacity. During the NFAT, Manitoba Hydro also indicated that it may want to split the northern HVDC corridor once Conawapa is in service.

QUESTION:

a) Please indicate whether there have been any changes to the planned integration, operation and configuration of Bipoles I, II and III in light of NFAT recommendations on generation assets.

b) Confirm the currently planned capacity of Bipole III compared to earlier designs.

c) Provide a detailed quantification of all added project components and project costs associated with any increase in planned capacity and configuration changes.

d) To the extent Manitoba Hydro made any decisions to upgrade Bipole III capacity or change the configuration of the northern HVDC system prior to the NFAT, please advise whether Manitoba Hydro has considered reversing that decision as a result of NFAT recommendations. Please summarize Manitoba Hydro's reasons.

RATIONALE FOR QUESTION:

This question explores the capital cost implications of capacity, configuration and operational changes.

RESPONSE:

a) There have been no changes to the planned integration, operation or configuration of Bipoles I, II and III as a result of recommendations from the NFAT process.

b) The Bipole III project includes both the installations of new HVDC converter equipment and associated ac system upgrades. The currently planned capacity of Bipole III remains at 2000MW. The HVDC converter equipment is being designed with a 15% overload capacity. To operate Bipole III as a 2300MW link, it would require further ac collector system upgrades as described in Section 2.3.1, Chapter 2 of the Manitoba Hydro NFAT filing.

c) The increased capacity of the HVDC converter equipment from 2000MW to 2300MW resulted in approximately a $50 million increase to the project's cost. This additional cost is not related to any additional components required, rather it represents the incremental cost to increase the capacity of the already planned (in-scope) HVDC converter equipment.

d) The capacity of Bipole III has not been reconsidered as a result of the NFAT recommendations and remains at 2000MW. The HVDC converter 2300MW rating will ensure sufficient capacity for future generation development, refurbishment of existing generation, and provide flexibility to take advantage of emerging export opportunities. The added cost to provide this HVDC converter capacity (from 2000MW to 2300MW) is marginal in comparison to the costs that would be incurred to add this capacity at a later date. Adding HVDC converter capacity at a later date would require the replacement of a substantial amount of equipment, control and protection modifications which would well exceed the cost of adding the HVDC converter capacity at this time.

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APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1505.07

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MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION

DATE: 2014 11 04
Financial Planning

Keeyask Generating Station

Addendum #4

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division: Dave Bo

Constructing Division: Dave B

Financial Department:
(if over $1 million) Doreen Perez

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager: [signature] OCT. 28, 2014

Business Unit V.P.:

Bruce A Barrett
31 Oct 2014

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$6,220,088,000
REVISED BUDGET $: (Total Net Cost)	$6,496,061,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2020 12
REVISED ISD: (Last Major In-service Date)	2020 12
RISK MATRIX/ BUSINESS CASE TIER:	n/a
INVESTMENT REASON:	CL04 Future Power Generation

OWNING DIVISION: New Generation Construction

I.M. NODE NUMBER: 1.5.1.6

W.B.S. NUMBERs: P:05866/P:14539/P:14621/P:14622/ P:15264/P:15955/P:16020/P:16021/ P:16022/P:16024/P:16895/P:18568/ P:14625/P:14703/P:16892/P:16897/ P:17448/P:21087/P:21089

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: J.D. Bowen

DATE PREPARED: 2014 10 21

REPORT NUMBER:

FILE NUMBER (Optional):

4	2014 03 20	Revision to budget	J.D. Bowen	
3	2012 09 06	Sensitivity Analysis Review	G.P.F. Schick	E.C. Minute 1418.04
2	2010 09 15	Re-estimate	G.P.F. Schick	E.C. Minute 1324.05
1	2009 03 06	Revision to budget	C. Michaluk/D. Magnusson	Board Minute # 797-09 06
	2008 10 15	CPJ	C. Michaluk	Board Minute # 796-08 04
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

Project Name (This section is required for all Addendums).
Keeyask Generating Station

Recommendation (This section is required for all Addendums).
That the project estimate be increased by $276 million to a revised total of $6,496 million.

Project Scope (This section is be filled out only if there is a change to the scope).
No Change

Background (This section is be filled out only if there is information relevant to the recommendation).

This CPJA reflects the control budget prepared as part of the NFAT and a detailed summary is provided below.

The Keeyask Project control budget was updated in March 2014. The last detailed project estimate was completed in 2009 with a detailed sensitivity analysis conducted in Summer of 2012. The control budget includes bid prices from the major contractors including the General Civil Contract and current budget of the Keeyask Infrastructure Project.

P50 Estimate:
The following changes were made to the P50 Estimate:

- Increase for actual escalation to bring the estimate to 2014$ with a subsequent decrease to future escalation resulting in no net change
- Increase for the difference between awarded value and estimate for the General Civil Works, plus the addition of a performance bonus
- Increase for post-construction adverse effects due to signed agreement
- Increase for site staffing due to partial augmentation through an external consultant
- Decrease to contingency based on an updated risk model

Reserves:
The following changes were made to the Management Reserves:

- Decrease to the labour & escalation reserves as a result of re-calculation using current information from the General Civil Contract

In-Service Costs:
The overall increase to the in-service cost of the project is $276M (5%). The increase to the in-service cost is due to increases to the P50 estimate and corresponding increase to interest offset by a decrease to management reserves and escalation.

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).
No change.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**

Other Alternatives Considered	**NPV Benefits/(Costs)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

The Labour and Escalation risks previously identified remain unchanged; however the reserve amounts have been re-calculated.

Labour:
The Labour Reserve was re-calculated using the methodology followed in 2012 but with new information as a result of awarding the General Civil Contract. Both the successful and the highest bidder, in combination with lessons learned, including the Wuskwatim project, were used as a basis of deriving the new reserve with an additional consideration of the successful bidder's contracting strategy.

Escalation:
The Escalation Reserve was re-calculated using the revised total project capital costs and associated cashflows.

Interest:
Interest has the potential to change the control budget significantly. Recent updates to interest may cause an increase to the control budget and in-service costs. This will be continuously evaluated over the life of the project.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).

No change.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 502,072	$ 502,072	$ -
2012/13	$ 201,778	$ 137,778	$ (64,001)
2013/14	$ 339,036	$ 277,396	$ (61,640)
2014/15	$ 405,137	$ 776,272	$ 371,135
2015/16	$ 636,463	$ 676,333	$ 39,870
2016/17	$ 883,863	$ 962,189	$ 78,326
2017/18	$ 1,132,127	$ 1,351,297	$ 219,170
2018/19	$ 955,395	$ 927,908	$ (27,487)
2019/20	$ 804,135	$ 616,472	$ (187,663)
2020/21	$ 288,155	$ 208,578	$ (79,577)
2021/22	$ 71,926	$ 55,193	$ (16,733)
2022/23	$ -	$ 4,470	$ 4,470
2023/24	$ -	$ 103	$ 103
Total	$ 6,220,088	$ 6,496,061	$ 275,973

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).

No change.

Related Projects (This section is be filled out only if changed).

No change.

Reference Documents (This section is be filled out only if changed).

2014 Public Utilities Board Report on the Needs for and Alternatives To
K-C NFAT Submission – Original NFAT submission
March 2014 Update - Presentation & Undertakings
2013/14 Power Resource Plan
CPJ dated October 15, 2008 - Keeyask Generating Station
CPJ Addendum #1 dated March 6, 2009
CPJ Addendum #2 dated September 09, 2010
CPJ Addendum #3 dated September 6, 2012

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1418.04

DATE: 2012 10 30
Financial Planning

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CAPITAL PROJECT JUSTIFICATION FOR

Keeyask Generating Station

Addendum #3

REVIEWED BY:
(Owning Dept Manager)

NOTED BY:
(if applicable)

Coordinating Division:

Constructing Division:

Financial Department:
(if over $1 million)

RECOMMENDED FOR IMPLEMENTATION:

Owning Div. Manager:

Business Unit V.P.:

PREV. APPROVED BUDGET $: (Use $ value from approved CPJ or last approved CPJ Addendum)	$5,636,949,000 CPJ#2
REVISED BUDGET $: (Total Net Cost)	$6,220,088,000
START DATE: (1st Cost Flow)	2002 04
PREV. APPROVED ISD: (Use In-service Date from approved CPJ or last approved CPJ Addendum)	2020 08
REVISED ISD: (Last Major In-service Date)	2020 12
RISK MATRIX/ BUSINESS CASE TIER:	n/a
INVESTMENT REASON:	CL04 Future Power Generation

OWNING DIVISION: New Generation Construction

I.M. NODE NUMBER: 1.5.1.6

W.B.S. NUMBERs: P:05866/P:14539/P:14621/ P:14622/P:15264/P:15955/P:16021/ P:16022/P:16895/P:18568/P:14625/ P:14703/P:16892/P:16897/P:17448

MAJOR ITEM ☒ **DOMESTIC ITEM** ☐

PREPARED BY: G.P.F Schick

DATE PREPARED: 2012 09 06

REPORT NUMBER:

FILE NUMBER (Optional):

2	2010 09 15	Re-estimate	G.P.F. Schick	E.C. Minute 1324.05
1	2009 03 06	Revision to budget	C. Michaluk/D. Magnusson	Board Minute # 797-09 06
	2008 10 15	CPJ	C. Michaluk	Board Minute # 796-08 04
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name (This section is required for all Addendums).
Keeyask Generating Station

Recommendation (This section is required for all Addendums).
That the project estimate be increased by $583 million to a revised total of $6,220 million.

Project Scope (This section is be filled out only if there is a change to the scope).
No Change

Background (This section is be filled out only if there is information relevant to the recommendation).

The last detailed project estimate was completed in 2009 with a detailed sensitivity analysis conducted in the Summer of 2012. This review incorporated up-to-date experiences and recent market information. The results of the review showed the need to adjust estimate to better address uncertainty related to future costs. As such, the recommended budget is based on a P50 estimate that includes all base costs and contingency at a 50% confidence level and management reserves for labour and escalation risks.

P50 Estimate:

Since the last estimate was developed in 2009 it was necessary to bring the estimate to 2012$ and several items in the point estimate had to be adjusted to match the increased level of detail that has been identified within the current scope. This resulted in the following changes to the P50 Estimate:

- $187M increase for actual escalation that has occurred to bring the estimate to 2012$.
- $34M increase to Planning & Licensing for additional adverse affects, regulatory and environmental costs related to Sturgeon activities, First Nation Activities and EIS preparation
- $60M increase toTransmission costs due to increased detail of scope to include tower type and numbers, additional lines from GS to Switching Stn, additional bank addition and breaker replacments
- $17M increase to infrastructure costs to upgrade camp for labour attraction and retention

Reserves:

A Management Reserve has been established to address significant risks related to labour ($384M) & escalation ($116M). See Risk Analysis section.

In-Service Costs:

The overall increase to the in-service cost of the project is $583M (10%). This increase to the in-service cost is due to the addition of the Management Reserve and base estimate increases offset by reduced interest costs from reduced forecasted interest rates ($215M).

JUSTIFICATION—BUSINESS CASE ANALYSIS (SUMMARY):

Justification and Link to Corporate/Business Unit Goals (This section is be filled out only if there is a change to some aspect of the recommended alternative).
An additional dependable energy source is required in 2019/20 to meet forecast Manitoba loads and export commitments consistent with the recommended development plan of the 2012/13 Power Resource Plan.

ANALYSIS OF ALTERNATIVES: (This section is be filled out only if there is a change to which alternative is being recommended).

Economic Analysis		
Discount Rate	% For current corporate rates see G911	For clarification on hurdle rates, contact Economic Analysis Department

Recommended Option	**NPV Benefits/(Costs)**

Other Alternatives Considered	**NPV Benefits/(Costs)**

Risk Analysis - (This section is be filled out only if there is a change to the project risk).

Keeyask risks related to labour productivity & escalation are addressed through use of management reserves due to the magnitude of the cost variation they may cause. Keeyask estimates include both a labour reserve and an escalation reserve:

The labour reserve represents the potential additional costs associated with labour productivity and cumulative impacts. The labour reserve is derived by applying outcomes of the Wuskwatim process reviews to the labour components of the Keeyask estimates including:

- Increases to the number of labour hours required per work activity and the resulting number of workers due to reduced labour productivity;
- Additional costs for extended construction duration due to lower productivity;
- Increases to collective agreement wages to attract and retain workers; Increases to the size of the camp to accommodate the additional workers required due to lower productivity;
- Increases to the service contracts to accommodate the additional workers required;
- Increases to project management costs related to additional supervisory staff to monitor less experienced and less productive workers; and
- Additional costs for 7-12 work schedule (7 days per week, 12 hours per day).

The Corporation expects to utilize the labour reserve if there are restrictions in our ability to address the current and expected state of the Canadian construction labour market (demand/supply), specifically labour availability and productivity. Examples include (a) restrictions on the ability to modify wage rates, hours

Risk Analysis - (This section is be filled out only if there is a change to the project risk).
of work per day, and turnaround schedules in the Burntwood Nelson Agreement, and (b) constraints on the project using labour outside of Manitoba and Canada. The escalation reserve represents the potential additional costs to the project associated with cost escalation greater than Canadian CPI. The escalation reserve is derived by projecting the total project capital costs utilizing rates of inflation comprised of components directly related to major hydro project construction, such as copper, cement, concrete reinforcing bar, and diesel fuel price increases, rather than the broadly defined components comprising Canadian CPI. The Corporation expects that it will utilize the escalation reserve. Considering the uncertainties in heavy construction escalation, labour productivity and project construction conditions, there is a greater likelihood that the actual costs to construct Keeyask will be less than the updated cost estimates than more. This is provided that the in-service dates, interest rates, escalation and major scope items are consistent with the estimate assumptions.

RESOURCE REQUIREMENTS AND CAPITAL BUDGET ESTIMATE:

Resource Requirements (This section is be filled out only if there is a change to the resource requirements).
No changes to the resource requirements.

Total Budget - (This section is required for all Addendums).

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$365,409	$365,409	$0
2010/11	$71,140	$56,434	($14,706)
2011/12	$152,465	$80,229	($72,236)
2012/13	$179,137	$201,778	$22,641
2013/14	$316,097	$339,036	$22,939
2014/15	$381,566	$405,137	$23,571
2015/16	$684,346	$636,463	($47,883)
2016/17	$750,677	$883,863	$133,186
2017/18	$1,082,934	$1,132,127	$49,193
2018/19	$813,264	$955,395	$142,131
2019/20	$631,995	$804,135	$172,140
2020/21	$207,919	$288,155	$80,236
2021/22		$71,926	$71,926
Total	$5,636,949	$6,220,088	$583,139

Proposed Schedule (This section is be filled out only if there is a change to the project schedule).
The PR 280 Upgrades started in October 2010 as outlined in CPJA#2 The Infrastructure started in December 2011 which is 6 months later than the date outline in CPJA#2 The first unit In-Service-Date is November of 2019 (unchanged from CPJA#2) and the last unit In-Service Date is December of 2020 (4 months later than CPJA#2).

Related Projects (This section is be filled out only if changed).
Conawapa Generating Station Transmission Lines related to Export Sales to Minnesota Power and Wisconsin Public Service Bipole III Transmission and Converters

Reference Documents (This section is be filled out only if changed).
2012 Keeyask & Conawapa Recommended Budgets 2012 Keeyask & Conawapa Sensitivity Analysis Summary 2012 EC Recommendation – Keeyask Budget Basis - August 28, 2012 Minute 1409.02 2012 Power Resource Plan Report

Section:	Tab 3	Page No.:	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
Issue:	Financial Targets		

PREAMBLE TO IR (IF ANY):

QUESTION:

With respect to page 14, line 21, please provide a schedule that sets out the capital cost of Keeyask as used in IFF11-2, IFF12, IFF13 and IFF14 and explain any material variances

RATIONALE FOR QUESTION:

Assist in understanding the factors affecting the change in the outlook for Manitoba Hydro's financial targets which goes to credibility of forecasts. Questions are distinct from those posed in PUB/Hydro 1-17.

RESPONSE:

The table below provides a comparison of the capital cost of Keeyask Generating Station from CEF13 to CEF14, as well as between CEF12 and CEF11-2 consistent with Figure 4.8 of the Application. The total capital cost of $6.2 billion is the same in both CEF12 and CEF13. However, there are small variations between categories which are discussed below.

Keeyask Generating Station - Continuity Schedule of CEF 11-2 through CEF 14 Budgets
(in millions $)

Cost Breakdown (in millions of dollars)	CEF 11-2	CEF 12		CEF 13	CEF 14
Generating Station (Including GCC and KIP)	2 756.1	2 969.9		3 060.1	3 657.9
Construction Power	21.8	29.2		30.4	30.4
Licensing & Planning	374.5	394.8		397.3	393.0
Transmission (excluding contingency)	118.5	138.0		138.3	142.1
Contingency & Management Reserves	573.1	1 046.9		1 063.7	685.2
Interest & Escalation	1 792.9	1 641.3		1 530.3	1 587.5
TOTAL	**5 636.9**	**6 220.1**		**6 220.1**	**6 496.1**

Note: Sunk Costs are included in each project component

Comparison of CEF13 to CEF14

The increase to the project cost of Keeyask for CEF14 versus the previous approved amount has been driven by several factors as discussed below:

Incorporation of Awarded Contract Amounts

The largest contract on the Keeyask Project is the General Civil Contract, which has now been awarded, and the awarded value is incorporated into the CEF14. The awarded value is greater than previous estimates, due in part to current market conditions. In addition, the awarded value of direct negotiated service contracts is greater than previous estimates.

Incorporation of Post-construction Adverse Effects

The budget was revised to incorporate the present value of post-construction adverse effect payments.

Finalization of Keeyask Infrastructure Project, Finalization of Construction Management Delivery Strategy, and Updated Estimates

The construction of the Keeyask Infrastructure Project was entering its final stages when CEF14 was established. There was an overall increase in construction costs, in part to reflect unforeseen site conditions. In addition, the construction management delivery strategy for the Generating Station Project was revised to incorporate staff augmentation by a consultant, where required. There was an overall increase in miscellaneous estimates, including stage 5 engineering, interface management, forebay clearing, environmental monitoring, and social mitigation.

Changes to Contingency and Management Reserves:

A complete risk and contingency review was conducted as part of establishing the revised control budget for the project. The risk identification and contingency development process was presented during the NFAT process. A revised P50 contingency and Management Reserve fund were developed at that time.

Increase in Capitalized Interest:

Capitalized interest in the project budget has increased since the last approved budget which has resulted from the change in base costs mentioned in the above categories as well as changes in cash flows. Interest has the potential to change the control budget significantly and will be continuously evaluated over the life of the project.

Comparison of CEF12 to CEF13

The change between CEF12 and CEF13 is primarily due to the reallocation of escalation to the Generating Station category, revising the estimate to reflect 2013 dollars.

Comparison of CEF11-2 to CEF12

The increase to the project cost of Keeyask for CEF12 versus CEF11-2 was driven by several factors as discussed below:

Inclusion of Labour & Escalation Management Reserve
A labour reserve was added to reflect potential additional costs associated with higher risk in labour productivity and cumulative impacts. An escalation reserve was added to reflect potential additional costs associated with cost escalation greater than Canadian Consumer Price Index (CPI).

Camp Accommodation Upgrade

The scope for the main construction camp was changed to be in-line with industry-style camps in order to reduce employee turnover at site and to attract and retain the work force.

Increase for licensing and planning costs

There were additional adverse effects payments added resulting from associated agreements, increased regulatory and environmental activities largely resulting from sturgeon (SARA), sturgeon stewardship and First Nation interests, additional First Nation labour, field training and disbursements for studies as well as increased costs for EIS preparation.

Detailed scope for Transmission Lines & Stations

The transmission line underwent more detailed scoping which identified the number and types of towers required as well as addition of line from the Generating Station to switching station. The transmission stations also underwent more detailed scoping which identified breaker replacements and bank addition requirements.

Changes to Interest and Escalation

The base dollars in the budget increased overall due to escalating the estimate from 2009 to 2012$, partially offset by a reduction to forecasted escalation. Capitalized interest decreased as a result of a reduction to forecasted interest rates.

Section:	Tab 4, Appendix 4.1	**Page No.:**	PUB/MH I-24(a)
Topic:	Capital Expenditures		
Subtopic:	Keeyask Project Costs		
Issue:	Revised cost estimate		

PREAMBLE TO IR (IF ANY):

MH has awarded contracts worth $2.74B with another $0.3B not yet awarded. This compares with a total project estimate of $6.496B.

QUESTION:

a) Provide the awarded contract item breakdowns requested in PUB/MH I-24(a).

b) File a redacted version on the public record and an unredacted version in confidence.

RATIONALE FOR QUESTION:

The Capital Project Justification (CPJ) sheets lack component cost details.

RESPONSE:

Contract	Status	Value	Type
General Civil Works	Awarded. Work Started	$1.4 B	Target Price
Turbines & Generators	Awarded. Work Started	[redacted]	Fixed Price
Main Camp Facility - Phase 1 & 2	Awarded. Work Started		Unit Price
Catering & Janitorial Services - Phase 1 & 2	Awarded. Work Started		Cost Reimbursable
Final Design Engineering	Awarded. Work Started		Unit Price
South Access Road	Not Awarded as of December 31, 2014	TBD	Unit Price
Staff Augmentation	Awarded for three year Term	TBD	Unit Price

Note 1: The above list includes contracts for which the awarded value or the estimated value exceeded $50M as of December 31, 2014.

Please note that escalation costs for the Keeyask total project estimate are based on standard corporate policy rates. An escalation reserve is also carried for the project which is intended to represent the potential additional costs to the project associated with cost escalation greater than Canadian CPI. The reserve is based on the additional costs associated with a standard year-over-year escalation rate of 2.5%, compared to escalation following Canadian CPI. This standard rate was obtained by taking the average escalation rate between the Canadian CPI and a composite escalation rate (or "basket" rate) of commodities typical of a hydroelectric generating station (e.g. steel, cement, construction labour, etc.). The composite escalation rate is developed by combining a number of individual market escalation indices (items such as construction labour, steel, cement, etc.), based on their estimated use in the construction of a generating station, to form a single composite rate. For each contract, specific escalation clauses apply which will cause a positive or negative change in the actual cost of the work depending on the indices which are driven by the marketplace. For example, the General Civil Contract has escalation clauses for craft labour, steel, fuel, cement, etc.

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Section:	Tab 3	Page No.:	13 - 15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Electric Operations Forecast		
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PREAMBLE TO IR (IF ANY):

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RATIONALE FOR QUESTION:

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RESPONSE:

The table below provides a comparison of the capital cost of Keeyask Generating Station from CEF13 to CEF14, as well as between CEF12 and CEF11-2 consistent with Figure 4.8 of the Application. The total capital cost of $6.2 billion is the same in both CEF12 and CEF13. However, there are small variations between categories which are discussed below.

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CAPITAL EXPENDITURE FORECAST (CEF14)

(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	40.5	12.9	14.7	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	776.3	676.3	962.2	1 351.3	927.9	616.5	208.6	55.2	4.5	0.1	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	1.9	4.7	9.3	6.8	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	43.4	31.4	21.0	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	14.1	9.1	12.9	1.3	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	6.6	23.5	24.6	22.0	31.7	29.5	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	114.1	51.6	3.8	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	15.8	17.1	13.8	4.3	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	-	-	-	-	-
Gillam Redevelopment and Expansion Program (GREP)	266.5	20.0	22.4	22.8	21.8	20.2	18.6	21.3	20.9	19.1	24.6	211.6
Bipole III - Transmission Line	1 655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	36.4	5.6	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	7.0	32.7	99.6	59.5	65.7	48.1	35.4	-	-	-	348.0
Demand Side Management	NA	51.8	59.2	76.6	83.9	93.7	78.2	72.5	60.8	50.0	49.6	676.2
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	2.8	33.0	33.6	34.3	35.0	138.6
Target Adjustment (Cost Flow)	NA	(161.3)	(51.4)	(61.1)	(12.7)	116.3	71.9	50.9	25.6	8.8	0.7	(12.2)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 451.7**	**1 913.9**	**2 463.5**	**2 577.8**	**1 530.9**	**884.0**	**426.2**	**196.1**	**116.6**	**110.0**	**11 670.7**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	7.2	0.7	14.0	26.4	29.6	40.9	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	2.7	2.7
Slave Falls Major Overhauls	126.1	-	-	-	-	-	2.5	2.4	19.4	18.8	19.9	63.0
Pointe du Bois GS Rehabilitation	182.9	10.1	15.4	47.0	50.0	25.2	9.8	11.2	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	15.8	14.2	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	6.0	0.4	17.5	7.8	18.8	50.4
Base Capital	NA	98.9	101.6	71.0	55.7	77.2	72.7	118.1	97.8	110.7	98.7	902.4
Total	**NA**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**132.0**	**134.6**	**137.3**	**140.1**	**1 336.1**
Transmission												
Rockwood East 230/115kV Station	53.3	26.6	11.1	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	14.2	35.8	8.2	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	1.3	3.7	37.0	13.9	1.6	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	1.0	8.6	8.8	8.9	23.3	23.7	24.2	24.7	27.9	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	8.7	8.5	2.7	5.2	2.2	2.3	2.4	2.7	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	2.1	13.2	22.9	56.9	57.9	59.0	21.8	233.7
Base Capital	NA	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63.0	128.2	777.0
Total	**NA**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**125.0**	**150.0**	**150.0**	**150.0**	**150.0**	**1 350.0**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	32.6	33.6	12.8	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	0.3	3.0	20.0	20.0	7.9	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	2.4	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	0.7	21.2	22.9	8.8	5.0	3.4	-	-	-	-	62.0
Base Capital	NA	197.0	182.6	209.6	160.7	173.0	193.3	206.0	210.1	214.3	218.6	1 965.3
Total	**NA**	**235.5**	**240.9**	**268.3**	**206.0**	**206.0**	**206.0**	**206.0**	**210.1**	**214.3**	**218.6**	**2 211.8**
Customer Care & Energy Conservation	**NA**	**3.2**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**3.6**	**3.7**	**3.7**	**39.2**
Human Resources & Corporate Services	**NA**	**75.0**	**75.0**	**55.0**	**55.0**	**55.0**	**55.0**	**55.0**	**56.1**	**57.2**	**58.4**	**596.7**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**2.2**
		570.9	**577.0**	**584.6**	**522.3**	**522.4**	**522.5**	**547.6**	**554.7**	**562.8**	**571.0**	**5 535.9**
Gas												
Customer Service & Distribution	**NA**	**34.9**	**49.0**	**34.9**	**22.3**	**21.2**	**24.4**	**26.1**	**27.7**	**30.0**	**28.3**	**298.8**
Customer Care & Energy Conservation	**NA**	**3.4**	**5.4**	**4.6**	**4.7**	**4.8**	**4.9**	**5.0**	**5.1**	**5.2**	**5.3**	**48.1**
Gas Demand Side Management	**NA**	**9.6**	**10.4**	**11.0**	**9.4**	**8.7**	**8.9**	**8.9**	**9.3**	**9.5**	**9.9**	**95.5**
		48.0	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**
Major & Base Capital Target Adjustment	NA	-	-	25.0	25.0	25.0	25.0	25.0	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**618.9**	**641.9**	**660.1**	**583.7**	**582.1**	**585.6**	**612.6**	**596.7**	**607.5**	**614.4**	**6 103.4**
CONSOLIDATED CEF14 TOTAL		**2 070.6**	**2 555.8**	**3 123.6**	**3 161.5**	**2 113.0**	**1 469.6**	**1 038.7**	**792.8**	**724.1**	**724.4**	**17 774.1**
ELECTRIC CAPITAL TOTAL		**2 022.6**	**2 490.9**	**3 073.1**	**3 125.2**	**2 078.3**	**1 431.5**	**998.8**	**750.8**	**679.4**	**681.0**	**17 331.7**
GAS CAPITAL TOTAL		**48.0**	**64.9**	**50.5**	**36.3**	**34.7**	**38.1**	**39.9**	**42.0**	**44.7**	**43.4**	**442.5**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	-	-	-	-	-	-	-	-	-	-	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	-	-	-	-	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	-	-	-	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	-	-	-	-	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	-	-	-	-	-	-	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	-	-	-	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	0.6	2.6	19.1	45.3	67.6
Gillam Redevelopment and Expansion Program (GREP)	266.5	24.4	26.3	4.2	-	-	-	-	-	-	-	266.5
Bipole III - Transmission Line	1 655.4	-	-	-	-	-	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	-	-	-	-	-	-	-	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	-	-	-	-	-	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	-	-	-	-	-	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	-	-	-	-	-	-	-	-	-	-	348.0
Demand Side Management	NA	47.5	48.3	47.2	47.2	48.3	50.2	52.2	54.4	56.6	58.9	1 186.9
Generating Station Improvements & Upgrades	NA	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	453.2
Target Adjustment (Cost Flow)	NA	0.2	(0.3)	1.4	1.8	1.2	1.1	(0.6)	(0.6)	(3.0)	(8.5)	(19.4)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**107.8**	**110.7**	**97.8**	**81.3**	**70.5**	**60.7**	**66.5**	**71.6**	**98.4**	**175.0**	**12 611.1**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major & Base Capital												
Electric												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	118.8
Jenpeg Overhaul Program	115.9	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	-	115.9
Slave Falls Major Overhauls	126.1	20.1	21.3	20.9	0.9	-	-	-	-	-	-	126.1
Pointe du Bois GS Rehabilitation	182.9	-	-	-	-	-	-	-	-	-	-	168.7
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	30.0
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	-	-	-	-	50.4
Base Capital	NA	119.9	103.0	106.0	127.5	153.4	112.3	164.3	163.5	167.4	170.8	2 290.6
Total	**NA**	**142.9**	**145.7**	**148.7**	**151.6**	**154.7**	**157.8**	**160.9**	**164.1**	**167.4**	**170.8**	**2 900.6**
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	37.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	58.2
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	57.5
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	34.7
Dorsey 230kV Phase II Zone Building	NA	-	-	-	-	-	-	-	-	-	-	-
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	-	-	-	-	-	-	233.7
Base Capital	NA	153.0	156.1	159.2	162.4	165.6	168.9	172.3	175.7	179.3	182.8	2 452.3
Total	**NA**	**153.0**	**156.1**	**159.2**	**162.4**	**165.6**	**168.9**	**172.3**	**175.7**	**179.3**	**182.8**	**3 025.3**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Customer Service & Distribution												
New Madison Station - 115/24kV Station	87.1	-	-	-	-	-	-	-	-	-	-	79.0
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.2
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	2.4
New Adelaide Station - 66/12kV	62.1	-	-	-	-	-	-	-	-	-	-	62.0
Base Capital	NA	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	305.3	4 773.2
Total	**NA**	**261.6**	**257.8**	**263.3**	**267.2**	**285.6**	**268.1**	**298.7**	**297.6**	**302.6**	**305.3**	**5 019.6**
Customer Care & Energy Conservation	**NA**	**3.8**	**3.9**	**4.0**	**4.1**	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**81.0**
Human Resources & Corporate Services	**NA**	**59.5**	**60.7**	**61.9**	**63.2**	**64.4**	**65.7**	**67.0**	**68.4**	**69.8**	**71.1**	**1 248.6**
Finance & Regulatory	**NA**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**4.9**
		621.1	**624.5**	**637.3**	**648.6**	**674.7**	**665.0**	**703.5**	**710.5**	**723.8**	**734.9**	**12 279.9**
Gas												
Customer Service & Distribution	**NA**	**33.7**	**33.5**	**34.0**	**34.7**	**36.6**	**34.1**	**38.2**	**39.3**	**40.2**	**41.0**	**664.1**
Customer Care & Energy Conservation	**NA**	**5.4**	**5.5**	**5.6**	**5.7**	**5.8**	**5.9**	**6.0**	**6.2**	**6.3**	**6.4**	**106.8**
Gas Demand Side Management	**NA**	**9.6**	**9.8**	**10.0**	**5.7**	**5.7**	**5.8**	**5.8**	**5.9**	**6.0**	**6.1**	**165.9**
		48.7	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**
Major & Base Capital Target Adjustment	NA	-	-	-	-	-	-	-	-	-	-	125.0
MAJOR & BASE CAPITAL TOTAL		**669.8**	**673.2**	**686.9**	**694.7**	**722.8**	**710.8**	**753.6**	**761.9**	**776.3**	**788.4**	**13 341.7**
CONSOLIDATED CEF14 TOTAL		**777.6**	**783.9**	**784.7**	**776.0**	**793.3**	**771.5**	**820.1**	**833.5**	**874.7**	**963.4**	**25 952.9**
ELECTRIC CAPITAL TOTAL		**728.9**	**735.1**	**735.1**	**729.9**	**745.3**	**725.7**	**770.0**	**782.2**	**822.2**	**910.0**	**25 016.1**
GAS CAPITAL TOTAL		**48.7**	**48.7**	**49.6**	**46.1**	**48.1**	**45.8**	**50.1**	**51.4**	**52.4**	**53.5**	**936.8**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	44.8	23.8	12.1	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	2.3	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	0.3	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	350.1	471.0	639.3	865.1	1 111.4	942.3	789.5	282.4	129.3	-	5 580.2
Conawapa - Generation	10 491.5	69.8	70.1	125.9	99.4	240.6	308.1	387.5	432.5	1 061.6	1 722.1	4 517.5
Kelsey Improvements & Upgrades	301.7	16.0	2.2	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	3.2	7.7	23.7	17.3	1.0	31.7	29.5	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	260.5	125.3	5.5	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	12.7	8.6	12.3	21.9	7.4	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	0.5	2.2	2.7
Gillam Redevelopment and Expansion Program (GREP)	366.5	-	27.0	30.2	30.5	29.5	27.9	26.3	29.1	28.7	26.8	256.0
Bipole III - Transmission Line	1 259.9	66.2	265.9	381.9	263.7	195.2	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	179.0	262.6	493.2	410.2	181.5	127.4	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	28.8	63.5	46.2	37.7	8.5	-	-	-	-	-	184.6
Community Development Initiative	60.8	53.9	2.2	2.0	1.8	0.9	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	74.1	40.8	0.7	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	0.0	10.8	8.9	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	0.4	3.8	29.7	101.1	58.7	63.5	91.7	0.1	-	-	349.0
St. Joseph Wind Transmission	10.0	0.0	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	28.1	25.3	24.6	23.9	22.6	21.7	19.9	18.9	18.8	18.7	222.4
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	2.8	33.0	33.6	34.3	103.7
Additional North South Transmission	475.0	-	-	-	-	-	-	-	4.1	4.4	51.6	60.2
Target Adjustment (Cost Flow)	NA	(119.0)	(33.9)	(46.0)	(8.2)	0.7	33.6	20.9	56.8	(42.0)	(62.1)	(199.3)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 071.1**	**1 376.5**	**1 790.2**	**1 864.4**	**1 858.1**	**1 556.0**	**1 368.1**	**856.8**	**1 234.8**	**1 793.6**	**14 769.6**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	14.2	8.0	5.0	21.9	30.2	27.0	16.0	-	-	-	122.3
Jenpeg Overhaul Program	115.9	-	-	-	-	-	-	-	-	-	-	-
Slave Falls Major Overhauls	126.1	-	0.2	0.9	5.3	26.6	30.3	31.8	26.9	4.2	-	126.1
Water Licenses & Renewals	56.8	7.6	7.0	7.0	6.5	2.4	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	10.2	10.3	15.3	21.7	19.5	20.4	24.2	19.5	17.1	9.6	167.9
Great Falls Unit 4 Overhaul	53.6	4.6	16.5	11.9	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	-	-	-	-	-	-	6.0	0.4	17.5	7.8	31.7
		36.7	42.1	40.2	55.3	78.6	77.7	78.0	46.7	38.8	17.5	511.6
Transmission												
Rockwood East 230/115kV Station	53.3	13.1	29.1	8.6	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	15.2	30.0	17.2	0.0	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	1.2	3.0	34.9	18.1	1.6	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	1.1	8.9	9.0	9.1	23.7	24.2	24.7	25.1	25.6	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	6.7	7.9	8.9	8.5	5.9	3.4	0.8	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	0.4	16.5	33.2	9.9	3.5	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	-	-	-	-	2.1	13.3	23.1	57.4	58.5	59.6	213.9
		36.2	71.0	78.4	36.0	35.2	73.6	57.9	85.5	83.6	85.1	642.6
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	2.1	20.0	25.6	16.1	1.3	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	0.1	0.3	3.0	20.0	20.0	7.9	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	0.0	2.5	0.5	3.0	16.5	20.0	9.3	-	-	-	51.8
Burrows New 66/12kV Station	54.7	8.7	5.1	-	-	-	-	-	-	-	-	13.8
		10.9	27.9	29.1	39.1	37.8	27.9	9.3	-	-	-	182.1
MAJOR CAPITAL TOTAL		83.8	141.1	147.7	130.5	151.7	179.2	145.1	132.3	122.4	102.6	1 336.3

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Base Capital												
Electric												
Generation Operations	NA	98.2	94.2	87.7	101.8	63.9	59.6	67.2	70.5	73.2	77.8	794.1
Transmission	NA	104.1	114.9	126.1	112.0	70.3	65.6	73.9	77.5	80.5	85.6	910.6
Customer Service & Distribution	NA	175.4	207.6	211.8	229.2	143.8	134.3	151.2	158.6	164.8	175.2	1 751.9
Customer Care & Energy Conservation	NA	3.1	3.1	3.2	3.3	3.3	3.4	3.5	3.5	3.6	3.7	33.6
Human Resources & Corporate Services	NA	61.4	75.7	54.8	54.8	34.4	32.1	36.2	37.9	39.4	41.9	468.6
Finance & Regulatory	NA	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	2.2
		442.4	495.8	483.7	501.3	316.0	295.2	332.1	348.3	361.8	384.4	3 961.0
Gas												
Customer Service & Distribution	NA	35.7	34.9	49.0	34.9	22.3	21.2	24.4	26.1	27.7	30.0	306.2
Customer Care & Energy Conservation	NA	13.7	13.4	12.3	12.1	10.1	9.3	8.5	8.5	8.4	8.5	104.8
		49.4	48.3	61.3	47.0	32.4	30.6	32.8	34.6	36.1	38.5	411.0
BASE CAPITAL TOTAL		**491.8**	**544.1**	**545.1**	**548.3**	**348.3**	**325.8**	**364.9**	**382.9**	**397.9**	**422.9**	**4 372.0**
CONSOLIDATED CEF13 TOTAL		**1 846.6**	**2 061.7**	**2 482.9**	**2 543.1**	**2 358.1**	**2 061.0**	**1 878.1**	**1 372.0**	**1 755.1**	**2 319.1**	**20 477.9**
ELECTRIC CAPITAL TOTAL		**1 597.2**	**2 013.4**	**2 421.6**	**2 496.1**	**2 325.7**	**2 030.5**	**1 845.3**	**1 337.4**	**1 719.1**	**2 280.6**	**20 066.8**
GAS CAPITAL TOTAL		**49.4**	**48.3**	**61.3**	**47.0**	**32.4**	**30.6**	**32.8**	**34.6**	**36.1**	**38.5**	**411.0**

CAPITAL EXPENDITURE FORECAST (CEF13)

(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	-	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	-	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	-	-	-	-	-	-	-	-	-	-	5 580.2
Conawapa - Generation	10 491.5	1 700.2	1 428.7	1 228.1	920.1	371.2	65.0	-	-	-	-	10 230.8
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	-	-	-	-	-	-	-	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	-	-	-	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	55.6	-	1 538.3
Gillam Redevelopment and Expansion Program (GREP)	366.5	32.3	32.1	34.0	11.9	-	-	-	-	-	-	366.5
Bipole III - Transmission Line	1 259.9	-	-	-	-	-	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	-	-	-	-	-	-	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	184.6
Community Development Initiative	60.8	-	-	-	-	-	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	-	-	-	-	-	-	-	-	-	-	349.0
St. Joseph Wind Transmission	10.0	-	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	19.1	18.7	17.9	16.2	16.0	16.3	16.6	16.9	17.3	17.6	395.1
Generating Station Improvements & Upgrades	NA	35.0	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	373.8
Additional North South Transmission	475.0	29.8	49.9	85.7	116.8	132.7	-	-	-	-	-	475.0
Target Adjustment (Cost Flow)	NA	(3.9)	22.6	13.3	23.8	49.5	34.0	20.2	11.1	17.1	6.2	(5.5)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 828.5**	**1 625.5**	**1 506.1**	**1 291.6**	**846.5**	**540.2**	**358.9**	**258.7**	**105.2**	**49.6**	**23 180.3**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major Capital												
Generation Operations												
Pine Falls Units 1-4 Major Overhauls	142.2	-	-	-	-	-	-	-	-	-	-	122.3
Jenpeg Overhaul Program	115.9	2.7	2.9	21.5	21.8	23.3	1.2	45.4	(3.4)	0.6	-	115.9
Slave Falls Major Overhauls	126.1	-	-	-	-	-	-	-	-	-	-	126.1
Water Licenses & Renewals	56.8	-	-	-	-	-	-	-	-	-	-	30.5
Pointe du Bois GS Rehabilitation	182.9	7.4	3.3	0.2	0.1	-	-	-	-	-	-	178.9
Great Falls Unit 4 Overhaul	53.6	-	-	-	-	-	-	-	-	-	-	33.1
Brandon Units 6 & 7 "C" Overhaul Program	50.4	18.8	-	-	-	-	-	-	-	-	-	50.4
		28.8	6.3	21.7	21.8	23.3	1.2	45.4	(3.4)	0.6	-	657.3
Transmission												
Rockwood East 230/115kV Station	53.3	-	-	-	-	-	-	-	-	-	-	50.7
Lake Winnipeg East System Improvements	64.6	-	-	-	-	-	-	-	-	-	-	62.4
Letellier - St. Vital 230kV Transmission	59.0	-	-	-	-	-	-	-	-	-	-	58.8
Transmission Line Upgrades for NERC Alert	151.3	-	-	-	-	-	-	-	-	-	-	151.3
HVDC Dorsey Synchronous Condenser Refurbishment	73.3	-	-	-	-	-	-	-	-	-	-	42.2
Dorsey 230kV Phase II Zone Building	63.4	-	-	-	-	-	-	-	-	-	-	63.4
Bipole 2 Thyristor Valve Replacement	233.7	19.8	-	-	-	-	-	-	-	-	-	233.7
		19.8	-	-	-	-	-	-	-	-	-	662.4
Customer Service & Distribution												
New Madison Station - 115/24kV Station	69.6	-	-	-	-	-	-	-	-	-	-	65.1
St. Vital Station - 115/24kV Station	51.3	-	-	-	-	-	-	-	-	-	-	51.3
Dawson Road Station - 115/24kV Station	51.8	-	-	-	-	-	-	-	-	-	-	51.8
Burrows New 66/12kV Station	54.7	-	-	-	-	-	-	-	-	-	-	13.8
		-	-	-	-	-	-	-	-	-	-	182.1
MAJOR CAPITAL TOTAL		**48.6**	**6.3**	**21.7**	**21.8**	**23.3**	**1.2**	**45.4**	**(3.4)**	**0.6**	**-**	**1 501.8**

CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Base Capital												
Electric												
Generation Operations	NA	71.7	83.9	81.5	81.1	81.0	83.7	76.5	84.0	84.5	84.6	1 606.6
Transmission	NA	78.8	92.3	89.7	89.3	89.1	92.1	84.2	92.4	93.0	93.1	1 804.4
Customer Service & Distribution	NA	251.7	261.6	257.8	263.3	267.2	285.6	268.1	298.7	297.6	302.6	4 506.1
Customer Care & Energy Conservation	NA	3.7	3.8	3.9	4.0	4.1	4.1	4.2	4.3	4.4	4.5	74.6
Human Resources & Corporate Services	NA	38.6	45.1	43.9	43.7	43.6	45.0	41.2	45.2	45.5	45.5	905.9
Finance & Regulatory	NA	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	4.8
		444.7	486.9	477.0	481.6	485.2	510.8	474.5	524.8	525.3	530.6	8 902.4
Gas												
Customer Service & Distribution	NA	28.3	33.7	33.5	34.0	34.7	36.6	34.1	38.2	39.3	40.2	658.8
Customer Care & Energy Conservation	NA	9.1	9.2	9.3	9.4	9.1	9.2	9.3	9.5	9.6	9.7	198.2
		37.4	42.9	42.8	43.4	43.8	45.8	43.5	47.7	48.9	49.9	857.0
BASE CAPITAL TOTAL		482.1	529.8	519.7	525.0	529.1	556.6	518.0	572.5	574.1	580.5	9 759.4
CONSOLIDATED CEF13 TOTAL		2 359.3	2 161.5	2 047.5	1 838.5	1 398.8	1 098.1	922.3	827.7	679.9	630.1	34 441.6
ELECTRIC CAPITAL TOTAL		2 321.9	2 118.6	2 004.7	1 795.1	1 355.0	1 052.3	878.8	780.0	631.0	580.2	33 584.5
GAS CAPITAL TOTAL		37.4	42.9	42.8	43.4	43.8	45.8	43.5	47.7	48.9	49.9	857.0

Section:	Tab 4	Page No.:	PUB/MH I-25(a)
Topic:	Capital Expenditures		
Subtopic:	Pointe du Bois Powerhouse Rebuild		
Issue:	Cost/Revenue Analysis		

PREAMBLE TO IR (IF ANY):

MH's CEF14 leaves some doubt as to whether the Pointe du Bois powerhouse rebuild has been cancelled completely.

QUESTION:

a) Please reconcile Manitoba Hydro's comments set out at page 117 of its NFAT final written submissions indicating that the Pointe du Boise powerhouse rebuild was cancelled with the table on page 2 of CEF14.

b) Please explain what expenditures Manitoba Hydro intents to make with respect to the powerhouse replacement.

RATIONALE FOR QUESTION:

This question seeks clarification on Pointe du Bois expenditures.

RESPONSE:

a) The reference in the NFAT final written submission to cancellation of the Pointe du Bois powerhouse rebuild was made in the context of other examples where Manitoba Hydro has adjusted its long term planning decisions in the past. In the specific reference to Pointe du Bois, the decision was made in 2009 to cancel the powerhouse rebuild component of a larger overall plan, the Pointe du Bois Modernization Project. This project would have resulted in Manitoba Hydro rebuilding both the Pointe du Bois spillway and powerhouse as an integrated project, with a powerhouse in-service date of 2016/17. The decision at that time was made to proceed with the Spillway Replacement Project and defer the powerhouse rebuild, which for planning purposes was revised to 2030/31. For IFF14, based on ongoing review and experience at Pointe du Bois, the powerhouse rebuild was further deferred to the 2040's timeframe under the expectation that operation of the existing powerhouse can be extended.

b) There are no committed expenditures for the Pointe du Bois powerhouse rebuild. The overall need and timing of capital expenditures for replacement of the Pointe du Bois powerhouse are under review.

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Canada utility seeks turbine-generators for 78-MW Pointe du Bois hydro project

Canada utility seeks turbine-generators for 78-MW Pointe du Bois hydro project

WINNIPEG, Manitoba, Canada
04/14/2015

Canadian utility Manitoba Hydro seeks proposals to design, supply and install turbines, generators and related equipment at the 78-MW Pointe du Bois hydroelectric project on the Winnipeg River in Manitoba. A mandatory site visit is set April 17 with responses due June 26.

Manitoba Hydro has been carrying out **a 20-year life extension of Pointe du Bois** by repair of existing generating equipment with the possibility of replacing some units. Other work at the plant includes a $560 million **spillway replacement project**. Alstom won a contract **in 2012** to supply gates and hoists for that project.

The utility now seeks to determine whether interest exists among qualified firms to manufacture, supply and install new turbines, generators and related equipment at Pointe Du Bois. It encouraged firms to review its request for proposals concerning Manitoba Hydro's anticipated commercial and technical needs in a potential contract. It called the RFP "an invitation and not an offer."

A solicitation notice may be obtained from the Canadian Public Tenders Internet site under **http://www.merx.com/English/SUPPLIER_Menu.asp?WCE=Show&TAB=3&PORTAL=MERX&State=7&id=PR326425&src=osr&FED_ONLY=0&ACTION=&rowcount=&lastpage=&MoreResults=&PUBSORT=2&CLOSESORT=0&IS_SME=N&hcode=JEvw%2fCbTn2zUNTPoZPOByQ%3d%3d**. A mandatory site visit is scheduled April 17.

For information, contact Manitoba Hydro, Purchasing Dept., P.O. Box 1287 STN MAIN, Winnipeg, MB R3C 2Z1 Canada; Fax: (1) 204-360-6130; E-mail: **purchasing@hydro.mb.ca**; Internet: **www.hydro.mb.ca**. For information about the Point du Bois project, see Manitoba Hydro's Internet site under **https://www.hydro.mb.ca/corporate/facilities/gs_pointedubois.shtml**.

Manitoba Hydro submits that it undertakes a focused level of optimization in its resource planning process and in the development plans that is appropriate for a meaningful and robust evaluation.

8.7 Manitoba Hydro Resource Planning is driven by Metrics

Manitoba Hydro has, in Chapter 8, Section 8.2 of the NFAT Business Case, detailed its process for establishing the development plans to be studied. CAC suggested in its closing submission that Manitoba Hydro perhaps "believes too deeply" in its plans. Mr. Wojczynski (Tr. p. 3696) addressed the notion that Hydro staff were "too invested" in the Preferred Development Plan. He testified that:

> "…people from Hydro, a lot of them, including myself, we're talking about engineers and accountants, … and MBAs, we're driven by metrics, customer reliability, security, our economics, the financial, the social benefit cost, metrics on environment and socioeconomic. We don't just do something because we happened to have been doing it in the past and want to carry on."

Mr. Wojczynski discussed examples where Hydro has indeed demonstrated that its decisions are made on the basis of objective criteria. Manitoba Hydro's direct evidence (MH Exhibit #129-7, Slide 11) includes a series of examples where, on account of changing circumstances, Manitoba Hydro has adjusted its decisions. These examples include the construction of Limestone which was commenced and then halted for over 10 years before it was built. Conawapa had previously been a committed project with PUB approval and signed contracts with Ontario and was subsequently cancelled. The Pointe du Bois powerhouse replacement project was cancelled and only the dam replaced when it became apparent that the economics did not support replacement of the powerhouse. Manitoba Hydro has also included combustion turbines and wind in its resources when it was economically feasible to do so. The GRE Diversity Exchange agreement has been extended, and DSM has been increased. Significantly, when new capital cost information became available in February, the PDP was taken back to the Manitoba Hydro Electric Board for their review and consideration as to whether Manitoba Hydro should continue to proceed with the Preferred Development Plan. These examples demonstrate Manitoba Hydro's ongoing commitment to making sound decisions based on the appropriate metrics, and suggestions to the contrary are unsupported by the evidence.

Integration of Perspectives & Overall NFAT Conclusion

Ed Wojczynski

March 25, 2014

MH Decisions on Proceeding with a Project is Based on What is Best for Ratepayers and Manitobans

- MH driven by metrics: customer reliability/security, MH economic/financial, social benefit/cost and environmental/socioeconomic
- MH previously halted Limestone, Conawapa, Pointe du Bois generation when circumstances changed
- MH developed 280MW gas generation in 2002
- MH purchased 258 MW wind generation
- MH negotiated GRE Diversity Exchange extension
- MH increasing DSM two to four times
- MH re-evaluated in February the Preferred Development Plan with new information and MHEB reaffirmed plan as being justified

6

Figure 4.1 Summary of Electric Capital Expenditure Forecast CEF14

(in millions of $)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Major New Generation & Transmission	**568**	**600**	**984**	**1 452**	**1 914**	**2 463**	**2 578**	**1 531**	**884**	**426**	**196**	**117**	**110**
Sustaining Capital (Major & Base)	**465**	**433**	**470**	**571**	**577**	**610**	**547**	**547**	**548**	**573**	**555**	**563**	**571**
Generation Operations	123	104	116	132	132	132	132	132	132	132	135	137	140
Transmission	116	104	103	125	125	125	125	125	125	150	150	150	150
Customer Service & Distribution	172	175	186	236	241	268	206	206	206	206	210	214	219
Customer Care & Marketing	3	3	3	3	4	4	4	4	4	4	4	4	4
Human Resources & Corporate Services	51	46	63	75	75	55	55	55	55	55	56	57	58
Finance & Regulatory	-	0	0	0	0	0	0	0	0	0	0	0	0
Target Adjustment	-	-	-	-	-	25	25	25	25	25	-	-	-
Total Electric	**1 033**	**1 033**	**1 454**	**2 023**	**2 491**	**3 073**	**3 125**	**2 078**	**1 432**	**999**	**751**	**679**	**681**

		Actuals						Forecast									
For the year ended March 31	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
1 **Cash Flow from Operations**	599.0	653.0	528.0	550.0	518.0	554.0	661.0	558.2	587.0	571.0	598.1	482.3	440.6	469.1	521.6	613.4	699.2
2 **Sustaining Capital Spending**	357.0	349.0	405.4	442.6	465.2	432.7	470.1	570.9	577.0	609.6	547.3	547.4	547.5	572.6	554.7	562.8	571.0
3 **Excess Cash Flow after Sustaining Capital Spending (1-2)**	242.0	304.0	122.6	107.4	52.8	121.3	190.9	(12.7)	10.0	(38.6)	50.8	(65.1)	(106.9)	(103.6)	(33.0)	50.6	128.2
4 **Capital Coverage Ratio (1/2)**	1.68	1.87	1.30	1.24	1.11	1.28	1.41	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22
5 **Major New Generation & Transmission**	473.0	538.5	674.0	657.5	567.8	600.3	983.7	1 451.7	1 913.9	2 463.5	2577.8	1530.9	884.0	426.2	196.1	116.6	110.0
6 **Financing Required to Fund MNG&T & Sustaining Capital**	231.0	234.5	551.4	550.1	515.0	479.0	792.8	1 464.4	1 903.9	2 502.1	2527.0	1596.0	991.0	529.7	229.2	66.0	0.0

For the year ended March 31	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
1 **Cash Flow from Operations**	787.0	818.3	942.7	1024.1	1146.3	1288.1	1431.7	1560.9	1655.5	1774.8
2 **Sustaining Capital Spending**	621.1	624.5	637.3	648.6	674.7	665.0	703.5	710.5	723.8	734.9
3 **Excess Cash Flow after Sustaining Capital Spending (1-2)**	165.9	193.8	305.4	375.5	471.5	623.1	728.2	850.4	931.7	1039.9
4 **Capital Coverage Ratio (1/2)**	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41
5 **Major New Generation & Transmission**	107.8	110.7	97.8	81.3	70.5	60.7	66.5	71.6	98.4	175.0
6 **Financing Required to Fund MNG&T & Sustaining Capital**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PUB/MH II-50

Reference: PUB/MH I-39 (a), PUB/MH I-134,CAC/MH I-15 (a)

b) Please indicate the total internally generated funds assumed to be used for this project. Provide detailed calculations in support of the estimate.

ANSWER:

Please see the attached schedule.

Manitoba Hydro
Analysis of Wuskwatim Project Sources and Uses of Cash Flows
Based on actuals available to March 31, 2011 and forecast based on IFF11-2

			Total	2012/13	2011/12	2010/11	2009/10	2008/09	2007/08	2006/07	2005/06	2004/05	2003/04 & Prev.
1	Total Capital Expenditures		8,132	1,244	1,114	1,134	1,117	932	869	680	522	520	
2	Less Total Base Capital		(3,659)	(453)	(458)	(477)	(438)	(388)	(391)	(383)	(311)	(361)	
3	**Total MNG&T Capital**	(2 -1)	**4,473**	**791**	**656**	**657**	**679**	**544**	**478**	**297**	**211**	**159**	
4	Total Wuskwatim Capital (Generation & Transmission)		1,672	71	213	326	367	254	207	77	36	36	85
5	% Total Wuskatim Capital/ Total MNG&T Capital	(4 / 3)	37%	9%	32%	50%	54%	47%	43%	26%	17%	23%	
6	Cash Flow from Operations		5,032	537	427	572	589	688	633	443	710	433	
7	Less Total Base Capital		(3,659)	(453)	(458)	(477)	(438)	(388)	(391)	(383)	(311)	(361)	
8	**Total Surplus Cash Flow from Operations for MNG&T Capital**	(6 - 7)	**1,373**	**84**	**(31)**	**95**	**151**	**300**	**242**	**60**	**399**	**72**	
9	Total Surplus Cash Flow from Operations Attributed to Wuskwatim Capital	(5 * 8)	481	8	-	47	82	140	105	16	68	16	-
10	Total Financing Activities Attributed to Wuskwatim Capital		1,191	64	213	279	285	114	102	61	(32)	20	85
11	**Total Wuskwatim Capital** (Generation & Transmission)		**1,672**	**71**	**213**	**326**	**367**	**254**	**207**	**77**	**36**	**36**	**85**
12	**Total IGF Allocated to Wuskwatim/Total Wuskwatim Capital Cost**	**(9 / 10)**	**29%**	**29%**	**30%**	**34%**	**40%**	**50%**	**46%**	**43%**	**54%**	**13%**	**0%**

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

c) Please provide a schedule that indicates the amount of cash flow from electric operations, forecast electric base capital spending and net cash flow available to finance Major Generation & Transmission Projects in each of the forecast years and provide the (electric) capital coverage ratio.

[			Y1	Y2 to Y20
Cash Flow from Operations (IFF11-2 Cash Flow Statement)	1			
Base Capital Spending (CEF11)	2			
Net Cash Flow	3	3 = 2-1		
Capital Coverage Ratio	4	4 = 1/2		

The following analysis should agree with the figures presented in IFF11-2 and CEF 11. If not please reconcile.

ANSWER:

Please see the following table.

		Actuals				Forecast								
For the year ended March 31	2008	2009	2010	2011	2012	2012	2013	2014	2015	2016	2017	2018	2019	2020
1 **Cash Flow from Operations**	599.0	653.0	528.0	550.0	518.0	434.2	438.6	444.2	446.9	518.9	574.2	563.7	499.2	580.4
2 **Base Capital Spending**	363.0	359.0	414.0	450.0	472.0	417.4	411.5	394.4	387.3	363.8	372.4	380.4	387.6	396.4
3 **Excess Cash Flow after Base Capital Spending (1-2)**	236.0	294.0	114.0	100.0	46.0	16.8	27.1	49.8	59.6	155.0	201.8	183.3	111.6	184.0
4 **Capital Coverage Ratio (1/2)**	1.65	1.82	1.28	1.22	1.10	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46
5 **Major New Generation & Transmission**	477.4	543.5	679.0	657.5	567.8	656.1	762.6	1060.0	1223.4	1566.9	1610.5	1953.0	1177.1	1412.0
6 **Cash Flow required to Finance MNG&T**	241.4	249.5	565.0	557.5	521.8	639.4	735.5	1010.1	1163.8	1411.9	1408.7	1769.7	1065.5	1228.0

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1 **Cash Flow from Operations**	514.1	716.6	832.0	920.9	1065.5	1175.2	1192.2	1294.5	1388.2	1501.2	1597.8	1748.2
2 **Base Capital Spending**	359.8	385.9	430.2	462.4	522.7	498.6	514.6	503.1	535.9	567.5	478.6	583.7
3 **Excess Cash Flow after Base Capital Spending (1-2)**	154.3	330.7	401.7	458.5	542.8	676.6	677.6	791.5	852.4	933.7	1119.2	1164.6
4 **Capital Coverage Ratio (1/2)**	1.43	1.86	1.93	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00
5 **Major New Generation & Transmission**	1445.8	1306.0	1071.8	933.3	1050.2	385.6	224.1	323.8	460.0	374.9	390.2	225.5
6 **Cash Flow required to Finance MNG&T**	1291.5	975.3	670.1	474.7	507.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Section:	Tab 4: App. 4.1 App. 11.37	**Page No.:**	PUB/MH I-67 c
Topic:	Capital Expenditure Forecast		
Subtopic:	Sustaining [Base] Capital Expenditures		
Issue:	Projected Spending Levels		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the analysis provided including the years covered by CEF08, CEF09, CEF10 and CEF11-2 , as well as actuals for each year, and comment on any changes in trends.

RATIONALE FOR QUESTION:

To explore changes in sustaining capital expenditure over time.

RESPONSE:

Please find the updated graph and table of corresponding data points below.

Comments on forecast trends are as follows:

As demonstrated in the graph, each CEF generally reflects higher spending plans in the early years resulting from detailed project planning and reallocation of cash flow. Following the early years, each CEF generally returns to a gradually increasing level of forecast spending at or below rates of inflation over the long term. Actual spending has been increasing over time to maintain reliable service and address capacity requirements for customers.

The CEF08 and CEF09 forecasts are essentially the same with some variation mainly due to the reallocation of cash flows.

In CEF10 over CEF09, spending increased over the long term to include provisions for future unidentified capital needs as a result of extending the CEF to a 20 year forecast period.

The CEF11-2 sustaining capital forecast remains the same as CEF10-2 through to 2020 followed by an increase to the provisions for future unidentified capital to account for additional capital requirements related to growth, renewal and replacement. Overall, CEF11-2 is lower than CEF10-2 due to the reduction of ineligible overhead capitalized.

The CEF12 sustaining capital forecast is higher in the first few years, as compared to CEF11-2, primarily due to:

- Transmission station requirements to address capacity constraints
- Supporting new customer service requests;
- The addition of the Gillam Townsite infrastructure refurbishment.

The changes between CEF12 and CEF11-2 in the later years are mainly due to a reallocation of cash flow, including the advancement and approval of the Bipole 2 Thyristor Valve Replacement project from the long term provisions for future unidentified capital.

The CEF13 sustaining capital forecast is higher in the first few years, as compared to CEF12, primarily due to:

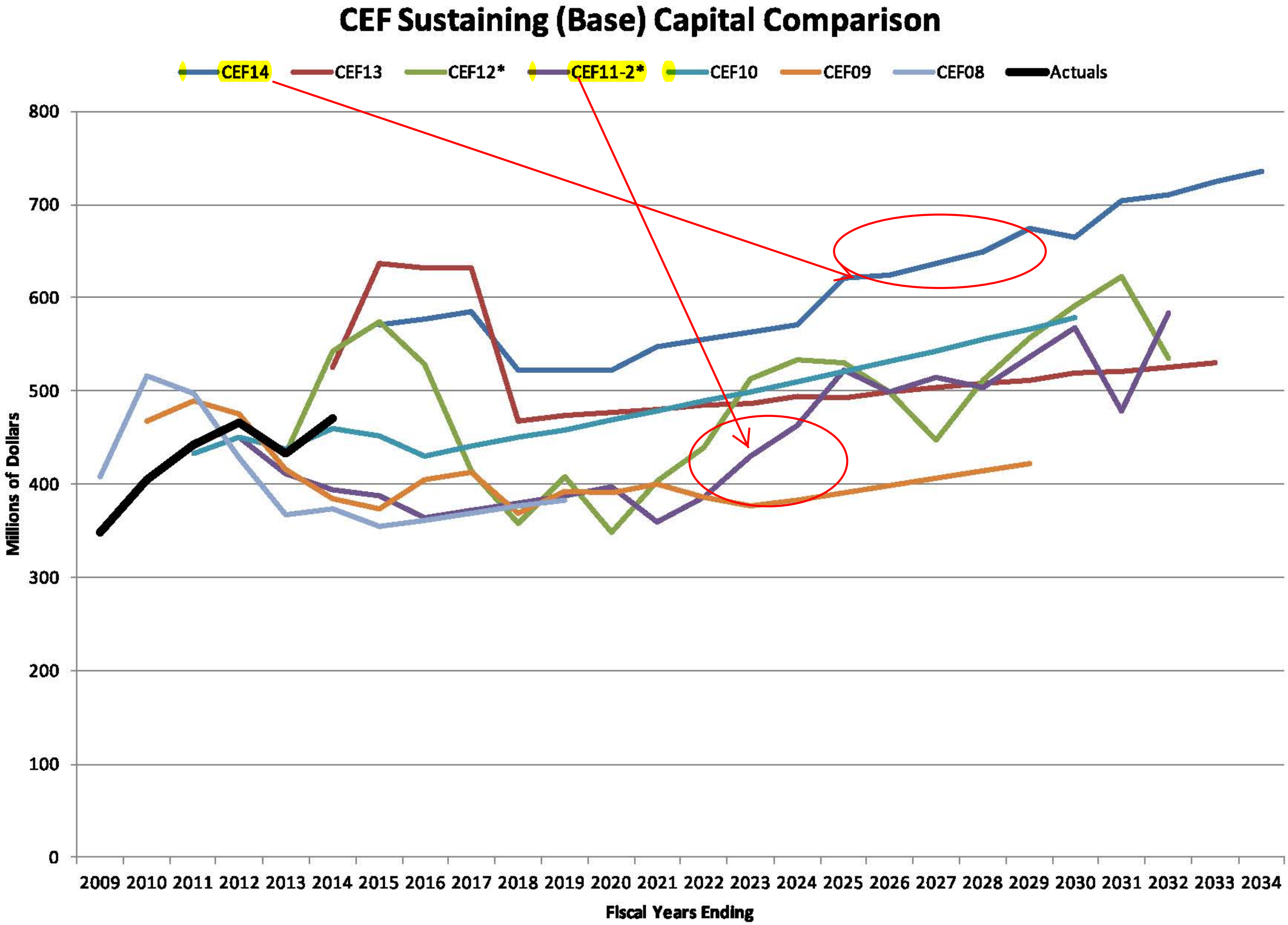
- Distribution substation development both within and outside the city of Winnipeg to address operational load conditions beyond maximum load ratings;
- Transmission line upgrades required to comply with NERC;
- Expenditures required to rehabilitate and replace aging assets based upon condition assessment data;
- Increased work required for the Great Falls Unit 4 Overhaul.

Beginning in 2017/18, base target values were reduced to more recent historic spending levels to 2021/22 and incorporates inflationary growth at 1% thereafter.

In CEF14, sustaining capital was decreased compared to CEF13 in the earlier years and spread out over the next four years to 2021/22 and incorporates inflationary growth at 2% thereafter. The overall increase in CEF14 over CEF13 reflects the findings of the Asset

Condition Assessment report as well as the impacts of capacity constraints and load growth. High priority areas of capital investment include:

- Distribution substation development both within and outside the city of Winnipeg to address operational load conditions beyond maximum load ratings;
- Supporting new customer service requests;
- Higher than average load growth exceeding firm capacity in certain geographic areas of the province;
- System capacity increases associated with Bipole III and new generation.


CEF Sustaining (Base) Capital Comparison
CEF14
CEF13
CEF12*
CEF11-2*
CEF10
CEF09
CEF08
Actuals
Millions of Dollars
800
700
600
500
400
300
200
100
0
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034
Fiscal Years Ending

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Sustaining Capital (in millions of $)

	CEF14	CEF13	CEF12*	CEF11-2*	CEF10	CEF09	CEF08	Actuals
2009							407	349
2010						467	517	405
2011					433	489	497	443
2012				451	451	475	428	465
2013			434	412	439	416	368	433
2014		526	543	394	460	384	374	470
2015	571	637	574	387	452	374	354	
2016	577	631	529	364	430	404	361	
2017	585	632	414	372	440	412	369	
2018	522	468	358	380	450	369	376	
2019	522	474	408	388	458	392	384	
2020	523	477	348	396	469	390		
2021	548	481	403	360	479	400		
2022	555	484	440	386	489	386		
2023	563	487	512	430	499	376		
2024	571	493	533	462	510	384		
2025	621	493	530	523	521	391		
2026	624	499	499	499	532	399		
2027	637	503	447	515	543	407		
2028	649	508	512	503	555	415		
2029	675	512	557	536	567	423		
2030	665	520	591	568	579			
2031	703	521	623	479				
2032	711	526	535	584				
2033	724	531						
2034	735							

*** Includes IFRS OH Adjustment made outside CEF in IFF***

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Table: Forced Outage Rate (%) for 2010 to 2014 - NON-WEIGHTED

2010		2011		2012		2013		2014	
Jenpeg	38.6	Poine Du Bois	46.8	Poine Du Bois	49.7	Poine Du Bois	43.2	Poine Du Bois	50.2
Poine Du Bois	30.5	Jenpeg	35.4	Jenpeg	29.3	Jenpeg	42.9	Jenpeg	45.5
Average	**7.7**	Slave Falls	19.4	Great Falls	20.3	Slave Falls	19.0	McArthur	18.2
Great Falls	5.7	**Average**	**12.4**	**Average**	**13.0**	Pine Falls	16.4	**Average**	**14.3**
Slave Falls	3.4	Seven Sisters	4.6	Slave Falls	6.5	**Average**	**13.2**	Pine Falls	13.3
Seven Sisters	2.9	Great Falls	3.3	Kettle	3.4	Great Falls	7.4	Slave Falls	7.3
McArthur	1.4	Pine Falls	2.6	Pine Falls	2.7	Kelsey	3.6	Great Falls	3.4
Pine Falls	1.3	Grand Rapids	0.9	Seven Sisters	0.7	Wuskwatim	3.5	Seven Sisters	1.8
Laurie River 1	0.4	Laurie River 1	0.8	Wuskwatim	0.6	Laurie River 2	2.6	Wuskwatim	0.6
Long Spruce	0.2	Kelsey	0.3	Grand Rapids	0.5	Grand Rapids	1.3	Grand Rapids	0.6
Kelsey	0.1	McArthur	0.3	Kelsey	0.4	McArthur	1.2	Kettle	0.6
Limestone	0.1	Laurie River 2	0.3	Long Spruce	0.3	Long Spruce	1.0	Limestone	0.6
Grand Rapids	0.0	Long Spruce	0.2	Limestone	0.3	Seven Sisters	0.7	Laurie River 2	0.3
Kettle	0.0	Kettle	0.1	Laurie River 1	0.3	Kettle	0.3	Kelsey	0.3
Laurie River 2	0.0	Limestone	0.1	Laurie River 2	0.2	Limestone	0.2	Long Spruce	0.1
Wuskwatim	na	Wuskwatim	na	McArthur	0.1	Laurie River 1	0.1	Laurie River 1	0.0

Variance MH14 vs MH11-2

Capital Expenditures (in millions of dollars)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Wuskwatim - Generation			41	13	15					
Keeyask - Generation	(26)	80	375	13	67	310	142	(100)	19	
Conawapa - Generation	(74)	(26)	(24)	(157)	(214)	(297)	(323)	(765)	(1 230)	(1 223)
Kelsey Improvements & Upgrades			14		13					
Kettle Improvements & Upgrades	(20)	(18)	(14)	16	17	14	24	22		
Pointe du Bois Spillway Replacement	(23)	137	37	39						
Pointe du Bois - Transmission				17	14					
Gillam Redevelopment and Expansion Program (GREP)			20	22	23	22	20	19	21	21
Bipole III - Transmission Line	(28)	(81)	(127)		142	420	75			
Bipole III - Converter Stations	(62)	(171)	(110)	227	472	344	136	18		
Bipole III - Collector Lines	(53)	(21)	36	50	33	27				
Bipole III - Community Development Initiative		54								
Riel 230/500kV Station	16	26	36							
Firm Import Upgrades	(20)									
Manitoba-Minnesota Transmission Project				29	66	(25)	(13)	48	35	
Demand Side Management		26	52	59	77	84	94	78	73	61
Generating Station Improvements & Upgrades									(12)	
CEF14 MNG&T Target Adjustment (Cost Flow)	118	(85)	(116)	(11)	115	(290)	194	149	77	29
Pine Falls Units 1-4 Major Overhauls	(15)	(23)	(32)	(45)	12	26	30	41		
Jenpeg Overhaul Program						(18)	(24)	(24)	(25)	(21)
Slave Falls Major Overhauls			(23)	(31)	(35)	(31)				19
Pointe du Bois GS Rehabilitation	(16)			15	47	50	25		11	
Great Falls Unit 4 Overhaul	(17)		16	14						
Brandon Units 6 & 7 "C" Overhaul Program										17
Rockwood East 230/115kV Station		13	27	11						
Lake Winnipeg East System Improvements		(11)	(15)	22						
Letellier - St. Vital 230kV Transmission					37	14				
Transmission Line Upgrades for NERC Alert							23	24	24	25
Dorsey 230kV Phase II Zone Building		(16)	(33)	(13)						
Bipole 2 Thyristor Valve Replacement							13	23	57	58
New Madison Station - 115/24kV Station			23	12	(11)					
St. Vital Station - 115/24kV Station					20	20				
Dawson Road Station - 115/24kV Station						17	20			
Burrows New 66/12kV Station	13	11								
New Adelaide Station - 66/12kV				21	23					

Variance MH14 vs MH11-2

Capital Expenditures (in millions of dollars)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Conawapa - Generation	(1 043)	(910)	(692)	(281)	(41)					
Pointe du Bois Powerhouse Rebuild		(16)	(38)	(91)	(158)	(245)	(404)	(313)	(216)	(53)
Gillam Redevelopment and Expansion Program (GREP)	19	25	24	26						
Demand Side Management	50	50	48	48	47	47	48	50	52	54
Generating Station Improvements & Upgrades	13	26	21	21	19	(47)	(36)	(53)	(160)	(97)
Additional North South Transmission				(318)						(57)
CEF14 MNG&T Target Adjustment (Cost Flow)	11		(306)	319						
Jenpeg Overhaul Program				21	22	23		45		
Slave Falls Major Overhauls	19	20	20	21	21					
Brandon Units 6 & 7 "C" Overhaul Program		19								
Transmission Line Upgrades for NERC Alert	28									
Bipole 2 Thyristor Valve Replacement	59	22								

Figure 4.1 Summary of Electric Capital Expenditure Forecast CEF14

(in millions of $)	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Major New Generation & Transmission	**568**	**600**	**984**	**1 452**	**1 914**	**2 463**	**2 578**	**1 531**	**884**	**426**	**196**	**117**	**110**
Sustaining Capital (Major & Base)	**465**	**433**	**470**	**571**	**577**	**610**	**547**	**547**	**548**	**573**	**555**	**563**	**571**
Generation Operations	123	104	116	132	132	132	132	132	132	132	135	137	140
Transmission	116	104	103	125	125	125	125	125	125	150	150	150	150
Customer Service & Distribution	172	175	186	236	241	268	206	206	206	206	210	214	219
Customer Care & Marketing	3	3	3	3	4	4	4	4	4	4	4	4	4
Human Resources & Corporate Services	51	46	63	75	75	55	55	55	55	55	56	57	58
Finance & Regulatory	-	0	0	0	0	0	0	0	0	0	0	0	0
Target Adjustment	-	-	-	-	-	25	25	25	25	25	-	-	-
Total Electric	**1 033**	**1 033**	**1 454**	**2 023**	**2 491**	**3 073**	**3 125**	**2 078**	**1 432**	**999**	**751**	**679**	**681**

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KEEYASK (ISD 2019/20)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	80	271	378	371	366	361	355	349	343	338	330	326	305	297	287
OM&A Costs	-	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15
Depreciation	-	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90
Capital Tax	8	12	17	23	28	31	32	32	31	31	30	30	29	29	29	28	28	27	27	26
Water Rentals	-	-	-	-	-	2	13	15	15	15	15	15	15	15	15	15	15	15	15	15
	8	12	17	23	28	124	395	528	521	517	511	505	498	492	486	479	473	452	443	434

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	11	20	20	20	19	19	18	18	18	17	17	16	15	15
OM&A Costs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	-	-	-	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	1	2	17	28	27	27	27	26	26	26	25	25	24	23	23	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	34	48	46	44	42	41	39	37	35	34	32	29	27	25
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	-	16	16	15	15	15	15	14	14	13	13	17	17	17	16
Capital Tax	0	0	0	1	2	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	0	1	2	3	68	87	84	82	80	78	76	74	72	69	72	69	66	64

WUSKWATIM
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	98	95	95	95	93	93	93	91	88	87	86	84	82	81	79	77	75	70	68	66
OM&A Costs	13	12	12	12	12	13	13	13	13	13	14	14	14	14	15	11	11	11	11	11
Depreciation	27	27	27	27	27	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28
Capital Tax	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	6	6	6	6	6
Water Rentals	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	151	147	148	148	146	146	146	144	141	140	139	137	136	134	133	127	125	120	118	116

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	13	23	19	15	132	249	246	241	234	228	222	216	210	204	197	190	185	171	163	156
OM&A Costs	-	-	-	-	8	12	12	12	13	13	13	13	14	14	14	15	15	15	15	16
Depreciation	7	11	12	12	70	100	100	100	100	100	100	100	100	100	99	99	99	99	99	99
Amortization of BPIII Reserve	-	-	-	-	-	(54)	(54)	(54)	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	7	11	17	22	23	23	23	23	22	22	21	21	20	20	19	19	18	18	17	17
	27	46	48	49	234	330	328	323	369	363	357	351	344	338	330	322	317	303	295	287

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	11	22	21	21	20	20	19	18	17	16	16	15	14	13	12	11	10	9
Amortization	-	-	8	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	-	-	19	36	35	34	34	33	32	31	30	30	29	28	27	26	26	24	23	22

POINTE DU BOIS SPILLWAY
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	14	29	32	32	31	31	31	31	30	30	29	29	28	27	27	26	26	24	23	23
OM&A Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Depreciation	4	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Capital Tax	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	20	39	42	42	41	41	41	40	40	39	39	38	37	37	36	35	35	33	33	32

DSM
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	11	11	13	16	19	21	23	23	23	22	21	20	18	17	17	16	16	15	15	16
OM&A Costs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2
Amortization	32	35	38	41	45	51	55	60	63	65	68	67	66	63	60	55	52	50	49	50
Capital Tax	1	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1
	44	49	53	60	66	75	81	86	89	90	91	90	87	83	79	74	71	68	68	69

SUSTAINING CAPITAL
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	17	50	86	120	150	180	215	242	261	286	311	334	362	389	412	433	456	457	472	494
Depreciation	8	25	43	63	81	100	117	134	149	163	179	193	206	222	236	251	264	279	295	309
Capital Tax	5	8	11	13	16	18	20	22	24	26	28	31	33	35	37	39	41	44	46	48
	31	82	140	196	246	298	352	398	434	475	519	558	601	646	686	723	762	780	813	851

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Incremental Revenue Requirement (without Net Extraprovincial Revenues)	281	375	468	556	800	1 052	1 460	1 668	1 738	1 765	1 793	1 814	1 834	1 858	1 874	1 880	1 904	1 872	1 882	1 897
Annual Rate Increase/(Decrease)	19.56%	5.20%	4.98%	4.11%	11.79%	10.66%	15.82%	6.72%	1.78%	0.42%	0.36%	0.12%	0.12%	0.22%	0.00%	-0.38%	0.12%	-1.46%	-0.32%	-0.15%
Cumulative Rate Increase	19.56%	25.78%	32.04%	37.47%	53.68%	70.05%	96.95%	110.19%	113.93%	114.82%	115.59%	115.85%	116.11%	116.59%	116.59%	115.77%	116.04%	112.88%	112.19%	111.88%
Net Extraprovincial Revenues	(150)	(181)	(147)	(142)	(160)	(195)	(459)	(554)	(569)	(588)	(586)	(521)	(528)	(505)	(496)	(491)	(469)	(449)	(427)	(414)
Total Incremental Revenue Requirement (with Net Extraprovincial Revenues)	131	194	321	413	640	857	1 001	1 114	1 169	1 177	1 208	1 292	1 306	1 353	1 378	1 389	1 435	1 424	1 455	1 483
Annual Rate Increase/(Decrease)	9.10%	3.88%	7.64%	4.82%	11.81%	9.86%	6.00%	4.27%	1.73%	-0.02%	0.72%	2.65%	0.08%	1.20%	0.46%	-0.12%	1.04%	-0.87%	0.49%	0.38%
Cumulative Rate Increase	9.10%	13.34%	22.00%	27.87%	42.97%	57.06%	66.49%	73.61%	76.60%	76.58%	77.85%	82.56%	82.70%	84.90%	85.75%	85.53%	87.45%	85.82%	86.74%	87.46%
IFF14 Annual Rate Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%
IFF14 Cumulative Rate Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%	59.18%	65.47%	72.01%	78.80%	85.86%	89.58%	93.37%	97.24%

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		Actuals							Forecast										
	For the year ended March 31	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1	**Cash Flow from Operations**	599.0	653.0	528.0	550.0	518.0	554.0	661.0	558.2	587.0	571.0	598.1	482.3	440.6	469.1	521.6	613.4	699.2
2	**Sustaining Capital Spending**	357.0	349.0	405.4	442.6	465.2	432.7	470.1	570.9	577.0	609.6	547.3	547.4	547.5	572.6	554.7	562.8	571.0
3	**Excess Cash Flow after Sustaining Capital Spending (1-2)**	242.0	304.0	122.6	107.4	52.8	121.3	190.9	(12.7)	10.0	(38.6)	50.8	(65.1)	(106.9)	(103.6)	(33.0)	50.6	128.2
4	**Capital Coverage Ratio (1/2)**	1.68	1.87	1.30	1.24	1.11	1.28	1.41	0.98	1.02	0.94	1.09	0.88	0.80	0.82	0.94	1.09	1.22
5	**Major New Generation & Transmission**	473.0	538.5	674.0	657.5	567.8	600.3	983.7	1 451.7	1 913.9	2 463.5	2577.8	1530.9	884.0	426.2	196.1	116.6	110.0
6	**Financing Required to Fund MNG&T & Sustaining Capital**	231.0	234.5	551.4	550.1	515.0	479.0	792.8	1 464.4	1 903.9	2 502.1	2527.0	1596.0	991.0	529.7	229.2	66.0	0.0

	For the year ended March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1	**Cash Flow from Operations**	787.0	818.3	942.7	1024.1	1146.3	1288.1	1431.7	1560.9	1655.5	1774.8
2	**Sustaining Capital Spending**	621.1	624.5	637.3	648.6	674.7	665.0	703.5	710.5	723.8	734.9
3	**Excess Cash Flow after Sustaining Capital Spending (1-2)**	165.9	193.8	305.4	375.5	471.5	623.1	728.2	850.4	931.7	1039.9
4	**Capital Coverage Ratio (1/2)**	1.27	1.31	1.48	1.58	1.70	1.94	2.04	2.20	2.29	2.41
5	**Major New Generation & Transmission**	107.8	110.7	97.8	81.3	70.5	60.7	66.5	71.6	98.4	175.0
6	**Financing Required to Fund MNG&T & Sustaining Capital**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PUB/MH I-22

Reference: IFF11-2 – Electric Operations

c) Please provide a schedule that indicates the amount of cash flow from electric operations, forecast electric base capital spending and net cash flow available to finance Major Generation & Transmission Projects in each of the forecast years and provide the (electric) capital coverage ratio.

[			Y1	Y2 to Y20
Cash Flow from Operations (IFF11-2 Cash Flow Statement)	1			
Base Capital Spending (CEF11)	2			
Net Cash Flow	3	3 = 2-1		
Capital Coverage Ratio	4	4 = 1/2		

The following analysis should agree with the figures presented in IFF11-2 and CEF 11. If not please reconcile.

ANSWER:

Please see the following table.

For the year ended March 31	2008	*Actuals* 2009	2010	2011	2012	*Forecast* 2012	2013	2014	2015	2016	2017	2018	2019	2020
1 **Cash Flow from Operations**	599.0	653.0	528.0	550.0	518.0	434.2	438.6	444.2	446.9	518.9	574.2	563.7	499.2	580.4
2 **Base Capital Spending**	363.0	359.0	414.0	450.0	472.0	417.4	411.5	394.4	387.3	363.8	372.4	380.4	387.6	396.4
3 **Excess Cash Flow after Base Capital Spending (1-2)**	236.0	294.0	114.0	100.0	46.0	16.8	27.1	49.8	59.6	155.0	201.8	183.3	111.6	184.0
4 **Capital Coverage Ratio (1/2)**	1.65	1.82	1.28	1.22	1.10	1.04	1.07	1.13	1.15	1.43	1.54	1.48	1.29	1.46
5 **Major New Generation & Transmission**	477.4	543.5	679.0	657.5	567.8	656.1	762.6	1060.0	1223.4	1566.9	1610.5	1953.0	1177.1	1412.0
6 **Cash Flow required to Finance MNG&T**	241.4	249.5	565.0	557.5	521.8	639.4	735.5	1010.1	1163.8	1411.9	1408.7	1769.7	1065.5	1228.0

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
1 **Cash Flow from Operations**	514.1	716.6	832.0	920.9	1065.5	1175.2	1192.2	1294.5	1388.2	1501.2	1597.8	1748.2
2 **Base Capital Spending**	359.8	385.9	430.2	462.4	522.7	498.6	514.6	503.1	535.9	567.5	478.6	583.7
3 **Excess Cash Flow after Base Capital Spending (1-2)**	154.3	330.7	401.7	458.5	542.8	676.6	677.6	791.5	852.4	933.7	1119.2	1164.6
4 **Capital Coverage Ratio (1/2)**	1.43	1.86	1.93	1.99	2.04	2.36	2.32	2.57	2.59	2.65	3.34	3.00
5 **Major New Generation & Transmission**	1445.8	1306.0	1071.8	933.3	1050.2	385.6	224.1	323.8	460.0	374.9	390.2	225.5
6 **Cash Flow required to Finance MNG&T**	1291.5	975.3	670.1	474.7	507.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Section:	Tab 3: Appendix 3.3	Page No.:	14-15
Topic:	Integrated Financial Forecast and Economic Outlook		
Subtopic:	Capital Expenditure Forecast		
Issue:	Changes in Capital Expenditure Forecast		

PREAMBLE TO IR (IF ANY):

Please read this question in light of PUB/MH 1-25.

QUESTION:

Please provide a schedule that compares the total annual electric capital spending in IFF11-2 with that in IFF14 for the years 2011/12 through 2031/32. Please include actuals for 2011/12 – 2013/14 when setting out the values for IFF14.

RATIONALE FOR QUESTION:

Information is required in order to understand the change in the capital expenditures forecast from that submitted in the last GRA. It goes to reasonableness of prioritization plans and to prudence of expenditures. The request seeks detail that differs from PUB/MH 1-25.

RESPONSE:

Please see the following table which compares the capital spending between MH14 and MH11-2 for the years 2012/13 to 2031/32. MH11-2 incorporated actual capital expenditures for 2011/2012 resulting in no variance for that fiscal year and has been excluded from this comparison.

Capital Expenditures (in millions of dollars)	**MH14**	**MH11-2***	**MH14 minus MH11-2**
2013	1 033	1 174	(141)
2014	1 454	1 454	(1)
2015	2 023	1 611	412
2016	2 491	1 931	560
2017	3 073	1 983	1 090
2018	3 125	2 333	792
2019	2 078	1 565	514
2020	1 432	1 808	(377)
2021	999	1 806	(807)
2022	751	1 692	(941)
2023	679	1 502	(823)
2024	681	1 396	(715)
2025	729	1 573	(844)
2026	735	884	(149)
2027	735	739	(4)
2028	730	827	(97)
2029	745	996	(251)
2030	726	942	(217)
2031	770	869	(99)
2032	782	809	(27)

+$3.2B

*Includes IFRS OH Adjustment

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Section:	Tab 4: Figure 4.13 5: Schedule 5.1.6	Page No.:	14
Topic:	Capital Expenditures		
Subtopic:	Electricity Capital In-Service Amounts		
Issue:	Conawapa Expenditures		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide the cumulative detail of the $397 million balance of Conawapa expenditures by major category in similar level of detail of the response to PUB/MH I-10 (a) (2012 GRA).

RATIONALE FOR QUESTION:

To understand MH's proposed treatment of Conawapa costs and the impact on revenue requirement.

RESPONSE:

Please see the following schedule which outlines the Conawapa expenditures by major category from 2004 to 2017.

CONAWAPA GS In thousands	2004	2005	2006	2007	2008	2009	Fiscal Year 2010	2011	2012	2013	2014	2015-2017	Total
Conawapa - Generation													
Internal MH Staff Costs	$ 49	$ 2 503	$ 4 790	$ 6 762	$ 6 338	$ 5 792	6 292	5 141	5 526	6 880	10 562	-	60 636
External Consultants hired by MH	148	4 096	8 167	12 585	11 748	12 591	6 674	5 238	2 869	4 551	7 176	-	75 842
MH Funded Expenses for Costs Incurred by Third Parties	-	26	415	3 107	1 540	670	1 313	628	59	352	2 263	-	10 371
Materials & Other	-	1 563	13 992	5 239	4 707	2 294	2 305	4 116	3 299	309	302	-	38 125
Joint Generation Development Agreements, Process and Study Costs	-	291	734	1 510	3 958	3 961	3 699	2 414	2 431	3 146	3 477	-	25 621
Mitigation	-	-	-	-	-	-	4 800	-	-	-	-	-	4 800
Capitalized Interest	-	(1)	-	3 434	5 740	8 120	10 087	12 187	14 019	15 496	16 716	-	85 798
Forecast Years:													
Pre-Suspension Activities	-	-	-	-	-	-	-	-	-	-	-		10 952
Negotiations and environmental assessments												5 306	
NFAT												2 872	
Engineering												2 206	
Regional Cumulative Effects assessment												293	
Public engagement programs												102	
Other												173	
Post-Suspension Activities	-	-	-	-	-	-	-	-	-	-	-		22 370
Aboriginal Traditional Studies												7 500	
Environmental Studies												9 600	
Close of negotiations and environmental assessment activities, regulatory activities and engineering												2 370	
Contingency & project management												2 900	
Capitalized Interest and Escalation	-	-	-	-	-	-	-	-	-	-	-	62 469	62 469
	197	8 478	28 098	32 636	34 030	33 429	35 169	29 724	28 203	30 733	40 496	95 791	$ 396 984

Section:	Tab 4; Appendix 11.35 & 11.36	**Page No.:**	PUB/MH I- 17a
Topic:	Capital Expenditures		
Subtopic:	Construction work in progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the schedule to include Conawapa.

RATIONALE FOR QUESTION:

This Information Request seeks background information on capital costs.

RESPONSE:

An updated Major New Generation and Transmission Construction Work In Progress schedule ("CWIP"), including Conawapa, is attached.

Please note that in IFF14, it was assumed that the deferred Conawapa costs of $397 million would be transferred out of CWIP into a regulatory deferral account and amortized over a period of 30 years commencing in 2016/17.

Major New Generation and Transmission Construction Work in Progress Continuity Schedule
(in millions of dollars)

	Opening Balance	2015 Net Capital Expenditure	2015 In-Service	2015 Closing Balance	2016 Net Capital Expenditure	2016 In-Service	2016 Closing Balance	2017 Net Capital Expenditure	2017 In-Service	2017 Closing Balance
Wuskwatim - Generation	2	41	40	2	13	4	11	15	26	(0)
Keeyask - Generation	917	776	-	1 693	676	-	2 370	962	-	3 331
Grand Rapids Hatchery Upgrade & Expansion	1	2	-	3	5	-	8	9	-	17
Conawapa	301	43	-	344	31	-	376	21	397	(0)
Kelsey Improvements & Upgrades	3	14	17	(0)	9	8	1	13	15	(1)
Kettle Improvements & Upgrades	4	7	6	5	24	24	5	25	24	5
Pointe du Bois Spillway Replacement	403	114	477	40	52	91	0	4	4	0
Pointe du Bois - Transmission	8	16	21	3	17	0	20	14	10	24
Gillam Redevelopment and Expansion Program (GREP)	-	20	18	2	22	24	1	23	24	(0)
Bipole III - Transmission Line	136	203	0	339	360	0	699	381	-	1 080
Bipole III - Converter Stations	301	221	123	399	581	-	979	829	-	1 808
Bipole III - Collector Lines	33	58	4	87	76	-	163	52	13	202
Bipole III - Community Development Initiative	54	2	-	56	2	-	58	2	-	60
Riel 230/500kV Station	287	36	329	(6)	6	0	(0)	-	-	(0)
Manitoba-Minnesota Transmission Project	2	7	-	9	33	-	42	100	-	141
Generating Station Improvements & Upgrades	-	-	-	-	-	-	-	-	-	-
MNG&T Target Adjustment (Cost Flow)	-	(161)	-	(161)	(51)	-	(213)	(61)	-	(274)
TOTAL	**2 452**	**1 400**	**1 036**	**2 810**	**1 855**	**152**	**4 505**	**2 387**	**513**	**6 371**

Major New Generation and Transmission Construction Work in Progress Continuity Schedule
(in millions of dollars)

	2018			2019			2020		
	Net Capital Expenditure	In-Service	Closing Balance	Net Capital Expenditure	In-Service	Closing Balance	Net Capital Expenditure	In-Service	Closing Balance
Wuskwatim - Generation	-	-	(0)	-	-	(0)	-	-	(0)
Keeyask - Generation	1 351	-	4 683	928	-	5 610	618	2 748	3 479
Grand Rapids Hatchery Upgrade & Expansion	7	24	0	-	-	0	-	-	0
Conawapa	-	-	(0)	-	-	(0)	-	-	(0)
Kelsey Improvements & Upgrades	1	1	(0)	-	-	(0)	-	-	(0)
Kettle Improvements & Upgrades	22	26	1	32	32	1	30	30	1
Pointe du Bois Spillway Replacement	(0)	-	0	(0)	-	0	(0)	-	0
Pointe du Bois - Transmission	4	28	0	-	-	0	-	-	0
Gillam Redevelopment and Expansion Program (GREP)	22	22	(1)	20	18	2	19	22	(2)
Bipole III - Transmission Line	494	106	1 468	75	1 487	57	-	-	57
Bipole III - Converter Stations	508	-	2 316	195	2 511	(0)	18	18	(0)
Bipole III - Collector Lines	37	6	233	5	237	0	-	-	0
Bipole III - Community Development Initiative	2	-	62	0	62	0	-	-	0
Riel 230/500kV Station	-	-	(0)	-	-	(0)	-	-	(0)
Manitoba-Minnesota Transmission Project	59	-	201	66	7	259	48	-	308
Generating Station Improvements & Upgrades	-	-	-	-	-	-	3	3	-
MNG&T Target Adjustment (Cost Flow)	(13)	-	(286)	116	-	(170)	72	-	(98)
TOTAL	**2 494**	**212**	**8 646**	**1 437**	**4 353**	**5 723**	**807**	**2 822**	**3 701**

REFERENCE: Chapter 14: Conclusions; Section: 14.0; Page No.: 1-2

QUESTION:

Please provide a detailed breakdown of the $50 million to be spent by the summer 2015 and the additional monies required to be spent in 2015, 2016, 2017 and 2018, before a final decision is made to construct Conawapa.

RESPONSE:

The $50 million to be spent on Conawapa by the summer of 2015 represents committed costs to protect an early in-service date of 2026, from the scheduled date of a NFAT decision (July 2014) to the filing of the Conawapa EIS (July 2015). Note that this $50 million is presented in 2014$ to represent the costs forecasted to be incurred from the time the NFAT report is issued and associated decisions are made by the summer of 2015.

The $50 million includes both money already planned to be spent during the July 2014 to July 2015 period to meet a 2026 ISD ($37 million) plus additional money ($11 million) committed to be spent by July 2015 (i.e. will be spent whether Conawapa proceeds or is canceled). These costs include approximately $28 million for licensing, $19 million for Generating Station Project Management and Engineering, and $1 million for Infrastructure.

Money to be spent in each year to protect a Conawapa 2026 ISD is as follows. Values are shown for each Fiscal Year Ending (i.e. FY 2015 covers April 1, 2014 to March 31, 2015) and values are shown in 2014$:

Fiscal year end- period from April 1st - March 31st

2014$

Costs Spent Up To March 31st 2012		$	230,000,000
Fiscal Year End	FY2013	$	45,272,701
	FY2014	$	58,957,877
	FY2015	$	45,981,143
	FY2016	$	43,861924
	FY2017	$	96,941,471
	FY2018	$	202,298,844
	Total	**$**	**723,313,959**

Activities in each year are as follows:

FY2015 – Final Stage IV and early Stage V Engineering work. Primary focus on pre-construction activities and aboriginal participation work to ensure a license can be obtained. Includes work related to EIS.

FY2016 – Detailed Stage V Engineering for both infrastructure and GS. Continued work related to licensing. Start development of T&G and GCC procurement documents.

FY2017 – Detailed Stage V Engineering for both infrastructure and GS and early procurement. Major focus on preparation of tender documents for GCC so that it could be issued as soon project approval is obtained.

FY2018 - Commencement of infrastructure construction work and major procurement contracts.

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Section:	Tab 3: App. 3.3 IFF14 Tab 11.4	**Page No.:**	PUB/MH I-11b/ Appendixes 11.4 & 11.15
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Wuskwatim Power Limited Partnership (WPLP)		
Issue:	Cost impacts to MH Ratepayers of the Amended WPLP Agreement		

PREAMBLE TO IR (IF ANY):

The WPLP IFF 14 includes finance expense of $75 million for 2014/15 and $77 million for 2015/16. Appendix 11.15 indicates finance expense of $95 million for each of the test years.

QUESTION:

a) Please provide the supporting calculation / detail of finance expense for WPLP based on IFF14.

b) Please indicate the amount of capitalized interest on MH's equity contribution to the project.

c) Please indicate what portion of equity contributions to WPLP in the 2013 WPLP Statement of Partners Capital ($219 million from MH and $108 million from TPC) is underwritten by MH debt.

d) Please indicate the finance expense which is not reflected in WPLP IFF14 and provide the calculation for its determination.

RATIONALE FOR QUESTION:

36T

RESPONSE:

a) The attached schedule provides the detailed finance expense calculation for IFF14 WPLP forecast.

b) Manitoba Hydro capitalized $42 million of interest on its equity contributions related to the Wuskwatim project.

c) The total amount of equity contributions as at March 31, 2013, financed by Manitoba Hydro were $311 million ($219 million from MH and $92 million from TPC). As at March 31, 2013, TPC had contributed $16.4 million of their own invested cash.

d) The finance expense associated with Manitoba Hydro's equity contributions to WPLP are not reflected in the IFF14 WPLP forecast. The amount of Manitoba Hydro's finance expense on its WPLP equity contributions is not determined separately from Manitoba Hydro's forecast of finance expense which is based on the consolidated borrowing requirements of the Corporation. Consolidated finance expense is not in practice subsequently allocated to capital or maintenance projects, activities or various functions. However, Appendix 11.15 for Wuskwatim is a representation of the Wuskwatim finance expense attributable to Manitoba Hydro except that it does not consider the interest income accruing on the NCN equity loan or the 33% of finance expense that is attributed to NCN through non-controlling interest. Notwithstanding these exceptions, the difference between the finance expense shown in Appendix 11.15 for Wuskwatim and the IFF14 WPLP forecast of finance expense provides an indication of the amount of finance expense related to Manitoba Hydro's equity contributions to WPLP.

Wuskwatim Power Limited Partnership
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
1 Project Debt	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
2 Long Term Debt	-	-	-	-	-	-	-	-	-	-
Short Term Debt	117	152	178	186	191	181	168	152	142	123
Interconnection Credit Facility	302	301	300	298	297	295	294	292	290	288
Sinking Fund Assets	(10)	(22)	(34)	(48)	(61)	(76)	(91)	(106)	(122)	(138)
Effective Interest Rates:										
WPLP Weighted Average GS Debt Rate	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%
MH Long Term Debt Rate	4.50%	5.10%	5.50%	5.80%	6.00%	6.20%	6.20%	6.20%	6.20%	6.20%
MH Short Term Debt Rate	1.95%	1.30%	2.40%	3.10%	3.45%	3.90%	3.90%	3.90%	3.90%	3.90%
Weighted Average Transmission Debt Rate	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%
MH Sinking Fund Rate	1.30%	1.65%	2.75%	3.45%	3.80%	4.25%	4.25%	4.25%	4.25%	4.25%
WPLP Interest Capitalization Rate	5.37%	5.24%	5.31%	5.38%	5.43%	5.49%	5.50%	5.51%	5.52%	5.53%
3 Interest on Project Debt	56	56	56	56	56	56	56	56	56	56
3 Interest on Long Term Debt	-	-	-	-	-	-	-	-	-	-
3 Interest on Short Term Debt	1	3	5	7	8	8	8	7	7	6
Interest on Interconnection Credit Facility	17	17	17	17	17	17	16	16	16	16
4 Interest Income	-	(0)	(1)	(1)	(2)	(3)	(3)	(4)	(4)	(5)
Interest Capitalized	(0)	(0)	(1)	-	-	-	-	-	(0)	-

Notes:

1 Total outstanding advances for 75% of the total capital requirements up to in-service.

2 Revolving credit facility for additional capital requirements following in-service.

3 Interest = Average of prior and current year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

4 Interest = Prior year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

Wuskwatim Power Limited Partnership
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
1 Project Debt	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
2 Long Term Debt	-	-	-	-	-	-	-	-	-	-
Short Term Debt	97	84	66	43	16	(22)	(67)	(119)	(117)	(118)
Interconnection Credit Facility	286	284	281	279	276	273	270	267	264	261
Sinking Fund Assets	(155)	(172)	(190)	(208)	(227)	(246)	(266)	(286)	(308)	(330)
Effective Interest Rates:										
WPLP Weighted Average GS Debt Rate	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%	5.62%
MH Long Term Debt Rate	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%
MH Short Term Debt Rate	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%
Weighted Average Transmission Debt Rate	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%	5.56%
MH Sinking Fund Rate	4.25%	4.25%	5.20%	5.20%	5.20%	5.20%	5.20%	5.20%	5.20%	5.20%
WPLP Interest Capitalization Rate	5.54%	5.55%	5.57%	5.58%	5.60%	5.63%	5.66%	5.71%	5.73%	5.73%
3 Interest on Project Debt	56	56	56	56	56	56	56	56	56	56
3 Interest on Long Term Debt	-	-	-	-	-	-	-	-	-	-
3 Interest on Short Term Debt	5	4	3	2	1	(1)	(2)	(5)	(6)	(6)
Interest on Interconnection Credit Facility	16	16	16	16	15	15	15	15	15	15
4 Interest Income	(6)	(6)	(9)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Interest Capitalized	-	-	-	-	-	-	-	-	(0)	-

Notes:

1 Total outstanding advances for 75% of the total capital requirements up to in-service.

2 Revolving credit facility for additional capital requirements following in-service.

3 Interest = Average of prior and current year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

4 Interest = Prior year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

WUSKWATIM
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	98	95	95	95	93	93	93	91	88	87	86	84	82	81	79	77	75	70	68	66
OM&A Costs	13	12	12	12	12	13	13	13	13	13	14	14	14	14	15	11	11	11	11	11
Depreciation	27	27	27	27	27	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28
Capital Tax	8	8	8	8	8	8	8	8	7	7	7	7	7	7	7	6	6	6	6	6
Water Rentals	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	151	147	148	148	146	146	146	144	141	140	139	137	136	134	133	127	125	120	118	116

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	13	23	19	15	132	249	246	241	234	228	222	216	210	204	197	190	185	171	163	156
OM&A Costs	-	-	-	-	8	12	12	12	13	13	13	13	14	14	14	15	15	15	15	16
Depreciation	7	11	12	12	70	100	100	100	100	100	100	100	100	100	99	99	99	99	99	99
Amortization of BPIII Reserve	-	-	-	-	-	(54)	(54)	(54)	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	7	11	17	22	23	23	23	23	22	22	21	21	20	20	19	19	18	18	17	17
	27	46	48	49	234	330	328	323	369	363	357	351	344	338	330	322	317	303	295	287

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	11	22	21	21	20	20	19	18	17	16	16	15	14	13	12	11	10	9
Amortization	-	-	8	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	-	-	19	36	35	34	34	33	32	31	30	30	29	28	27	26	26	24	23	22

Estimated Impacts of Wuskwatim on Net Income

($Millions)

	IFF09		IFF10		IFF11-2	
Projected capital cost of Wuskwatim (Including Transmission)	1,591		1,566		1,672	
	2012/13	2013/14	2012/13	2013/14	2012/13	2013/14
Finance expense (net of internally generated funds)	61	62	61	61	65	71
OM&A costs	6	6	7	8	8	10
Depreciation	27	27	23	26	23	25
Capital tax and water rentals	10	10	10	10	10	11
Income statement impacts *	104	105	101	105	106	117

* Before non-controlling interest

SCHEDULE 1

Keeyask Hydro Power Limited Partnership
Summary of Debt Balances and Finance Expense
($Millions)

For the fiscal years ending March 31	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
[1] Project Debt	4,000	4,200	4,200	4,200	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354	4,354
[2] Long Term Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Debt	153	53	120	152	13	22	37	44	44	39	23	(10)	(55)	(307)	(235)
Interconnection Credit Facility	199	201	200	199	198	197	196	194	193	192	190	188	187	185	183
Mitigation Liability	112	113	113	114	114	115	115	116	116	116	118	119	121	122	124
Sinking Fund Assets	-	-	43	87	134	183	235	288	343	401	461	523	588	655	725
Effective Interest Rates:															
Total KHLP Weighted Average GS Debt Rate	5.38%	5.41%	5.41%	5.41%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%
MH Long Term Debt Rate	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%	6.20%
Total MH Short Term Debt Rate	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%	4.90%
Weighted Average Transmission Debt Rate	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%	4.94%
Weighted Average Mitigation Liability Debt Rate	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%
MH Sinking Fund Rate	0.00%	0.00%	0.00%	2.68%	3.23%	3.46%	3.59%	4.49%	4.57%	4.62%	4.66%	4.69%	4.71%	4.73%	4.75%
Interest Capitalization Rate	5.28%	5.39%	5.39%	5.39%	5.39%	5.44%	5.44%	5.44%	5.44%	5.44%	5.44%	5.45%	5.46%	5.52%	5.55%
[3] Total Interest on Project Debt	208	225	227	227	227	237	237	237	237	237	237	237	237	237	237
[3] Interest on Long Term Debt	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
[3] Total Interest on Short Term Debt	4	3	4	6	8	1	1	2	2	2	1	0	(1)	(8)	(10)
Interest on Interconnection Credit Facility	3	10	10	10	10	10	10	10	10	9	9	9	9	9	9
Mitigation Liability	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
[4] Interest Income	-	-	-	(2)	(4)	(6)	(8)	(12)	(14)	(17)	(20)	(23)	(26)	(29)	(33)
Interest Capitalized	(201)	(62)	-	-	-	-	-	-	-	-	(0)	-	-	-	-

Notes:

[1] Total outstanding advances for 75% of the total capital requirements up to in-service.

[2] Revolving credit facility for additional capital requirements following in-service.

[3] Interest = Average of prior and current year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

[4] Interest = Prior year debt balance * nominal interest rate $((1+\text{effective rate})^{1/12}-1)*12$

SCHEDULE 2

Keeyask Hydro Power Limited Partnership
Interest Capitalized on Manitoba Hydro Equity Contributions
($Millions)

For the fiscal years ending March 31	2015	2016	2017	2018	2019	2020	2021	2022
Interest Capitalized on 82.5% of Total Equity	12	23	35	50	67	73	23	-
[1] Accrued Interest on KCN Common Unit Equity Loans During Construction	1	3	6	10	15	19	21	8
Total Interest Capitalized During Construction	13	26	41	61	81	91	44	8

Notes:

[1] At Final Close it is assumed KCN elects the preferred equity option. The interest on the common unit loans is transferred to Manitoba Hydro.

KEEYASK (ISD 2019/20)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	80	271	378	371	366	361	355	349	343	338	330	326	305	297	287
OM&A Costs	-	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15
Depreciation	-	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90
Capital Tax	8	12	17	23	28	31	32	32	31	31	30	30	29	29	29	28	28	27	27	26
Water Rentals	-	-	-	-	-	2	13	15	15	15	15	15	15	15	15	15	15	15	15	15
	8	12	17	23	28	124	395	528	521	517	511	505	498	492	486	479	473	452	443	434

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	11	20	20	20	19	19	18	18	18	17	17	16	15	15
OM&A Costs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	-	-	-	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	1	2	17	28	27	27	27	26	26	26	25	25	24	23	23	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	34	48	46	44	42	41	39	37	35	34	32	29	27	25
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	-	16	16	15	15	15	15	14	14	13	13	17	17	17	16
Capital Tax	0	0	0	1	2	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	0	1	2	3	68	87	84	82	80	78	76	74	72	69	72	69	66	64

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U.S. off-coal plans could benefit Canadian electricity producers

SHAWN McCARTHY - GLOBAL ENERGY REPORTER

OTTAWA — The Globe and Mail

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Canadian electricity producers are positioning themselves to benefit from U.S. efforts to reduce reliance on coal-fired power, and are lobbying the U.S. Environmental Protection Agency for its seal of approval.

Utility executives have been regular visitors to Washington as they aim to ensure that their American customers can take full credit for imported hydro power as a way of reducing greenhouse gas (GHG) emissions. Their push comes even as Republicans in Congress vow to block President Barack Obama's off-coal initiative.

The EPA is due to release its final rules this summer on how states can comply with new carbon regulations announced by Mr. Obama as part of his government's effort to reduce GHG emissions. Its inclusion of imported power from hydroelectric projects would represent a major boost for utilities such as Manitoba Hydro and Hydro-Québec, which are already increasing their exports to the U.S.

But that's not a sure bet.

"It's definitely not clear that the EPA will accept hydro power imported from Canada in the same way it accepts domestic renewables or hydro power," said Kyle Aarons, senior fellow with the Washington-based think tank, Center for Climate and Energy Solutions. The group presented a paper on Canadian hydro power at a conference in the U.S. capital this week.

"I think there are a lot of reasons why the EPA should treat Canadian hydro power similarly," Mr. Aarons said in an interview. "We don't seen why there should be a distinction and we're not alone in that view, but at this point, it's impossible to say what the EPA is going to do."

Canadian electricity exports have more than doubled since a recent low in 2003, rising from 30 million megawatt-hours to 60 million in 2013. Although the pictures differs widely among provinces, Canada gets 80 per cent of its electricity from non-emitting sources, primarily water power but also nuclear, wind and solar. The U.S., by contrast, relies on coal for 40 per cent of its electricity generation.

Under a clean energy plan announced by Mr. Obama, U.S. states must reduce carbon emissions in their power sector by 30 per cent from 2005 levels by 2030, an aggressive target that can only be met by shuttering coal plants and using more non-emitting sources. Senior Republicans such as Senate Majority Leader Mitch McConnell of Kentucky decry the administration's "war on coal" and are seeking every means at their disposal to thwart it, including encouraging states to simply not comply with the EPA rules.

The Harper government has urged the Obama administration to ensure that electricity trade is seamless across the border and that Canada's non-emitting power be considered a key part of the solution in the U.S. climate effort.

Mr. Aarons said the EPA has outlined three possible options: fully crediting any increase in imports of hydro power imports, not crediting them at all, or providing credit only for imports from newly built projects. Imports of nuclear-generated power would only be credited if they come from new plants, and there are no plans to build reactors in Canada.

Quebec and Manitoba are in the forefront of the growth in exports, although provinces such as Ontario and British Columbia have also increased sales to the United States. American regulators recently approved the Champlain Hudson Power Express, a 1,000-megawatt transmission line that will deliver power form Hydro-Québec to New York City.

Approval was also given for the Great Northern Transmission Line, a 1,883-megawatt line that ? will bring electricity from Manitoba to Minnesota. That line has the added benefit of allowing Minnesota more leeway to fully utilize its wind and solar power by having access to electricity from the province that can be called on when the state's intermittent generation is unavailable.

In its submission to the EPA, the Canadian Electricity Association said the imported electricity from Canada will help states reduce the cost of compliance with the climate rules while ensuring the reliability of the grid.

TECHNOLOGY 144

CANADIAN HYDROPOWER AND THE CLEAN POWER PLAN

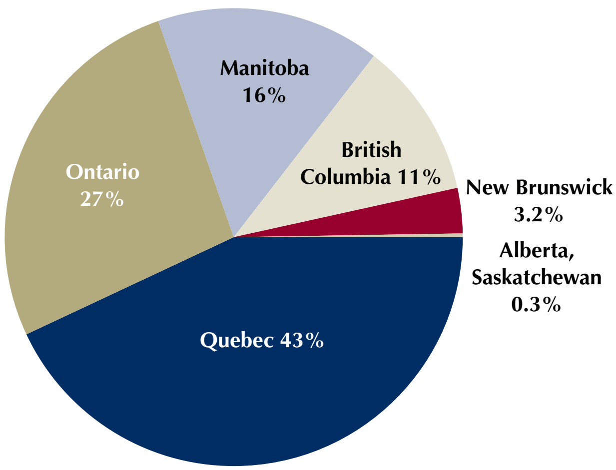
CENTER FOR CLIMATE AND ENERGY SOLUTIONS

by

Kyle Aarons
Doug Vine
Center for Climate and Energy Solutions

April 2015

FIGURE 7: Canadian Electricity Exports by Province, 2013



Source: National Energy Board of Canada, "Commodity Statistics: Electricity: Electricity Exports and Imports: Table 2A." February 2015. Available at: https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx?language=english

CHALLENGES TO INCREASED TRADE

There are physical, financial, policy, and political constraints that must be overcome in order to increase Canadian hydroelectricity flows to the United States. Additional infrastructure, including new hydropower facilities and new transmission lines are required. Furthermore, bilateral contracts in some regions can assist in obtaining project financing for new hydropower, ensuring timely project development. Also, new projects, transmission infrastructure, and power contracts are subject to a variety of state, provincial and federal regulations, which can become political matters with many stakeholders to satisfy. Finally, policies like U.S. state renewable portfolio standards (RPS) and the Clean Power Plan, and their treatment of hydropower generation in general and international hydropower imports from Canada in particular, will have a direct impact on the future level of imports to the United States.

The border provinces of Québec, Ontario, Manitoba, and British Columbia trade the majority of electricity with the United States **(Figure 7)**. While electricity sources are more diversified in Ontario, hydropower is responsible for more than 95 percent of electricity generated in Québec, Manitoba, and British Columbia. In a typical year, Québec, Ontario, and Manitoba generate more electricity than they require, providing an opportunity to participate in export markets. However, to expand exports beyond the present level, additional generation and transmission capacity will be required.

As noted above, more than 4,000 MW of new hydropower capacity was either under construction or had recently been commissioned in Canada as of early 2015. Some of this new generation will meet expected domestic demand growth, and some will replace retiring thermal plants. New projects face scrutiny from a range of sources. First Nations, native people in Canada, who have been directly impacted by hydropower project development without serious consultation in the past are today, more often than not, seeing their issues addressed as part of the development process. Environmentalists on both sides of the border have expressed opposition to new, large hydropower projects. However, power companies have been working to address and mitigate many of their concerns. In recent years, advances have been made in the design of facilities, which minimize flooding and impacts on fish. Additionally, many new plants in Canada are being built far from populations, where there is very little in the way of agriculture or existing infrastructure.

In most instances, individual Canadian province electrical grids are better connected with bordering U.S. states than with adjacent provinces. Still, additional transmission capacity will be required to increase electricity exports. Several new international transmission lines have been proposed, most along existing rights-of-way; some projects are further along than others. For example, the Champlain Hudson Power Express is a 1,000 MW high-voltage direct current (HVDC) transmission line from the Canadian border to New York City expected to go into service in 2017.[41] Additionally, the Lake Erie Connector is a 1,000 MW HVDC line that is expected to link Ontario's Independent Electricity System Operator (IESO) and PJM in 2019.[42] Also in the northeast, the proposed Northern Pass Transmission Line from the Canadian border to a substation in Franklin, New Hampshire, will provide 1,200 MW of hydropower from Hydro-Québec to the New England power grid, but project developers are still working with stakeholders to resolve cost-responsibility, environmental, and social issues.[43] In the upper Midwest, the Federal Energy Regulatory Commission (FERC) has recently approved construction of the Great Northern Transmission Line.[44] The line from the Canadian border to a substation near Grand Rapids, Minnesota, will provide 883 MW of capacity, 383 MW of which will be used to deliver hydroelectric power from Manitoba Hydro to Minnesota Power's customers.[45] This project should be especially beneficial from the perspective of zero-carbon electricity, as it will allow Minnesota to back up intermittent wind power with hydropower and send any excess wind power to Manitoba.[46]

Electricity generators that have a power purchase agreement (PPA) in place are likely to find it easier to obtain financing for new power projects. A PPA is a long-term contract for electric power between a power generator and a purchaser, often an electric utility.[47] Generators value PPAs because the agreements guarantee a predictable revenue stream for delivered power over many years, while utilities like these contracts because they secure electricity price certainty in what can be a volatile market. Notably in 2011, two Canadian hydropower generators secured long-term PPAs with U.S. utilities. Minnesota Power and Manitoba Hydro inked a 15-year deal for 250 MW, beginning in 2020.[48] Also in 2011, the Vermont Public Service Board approved a 26-year, 225 MW PPA between Hydro-Québec and 20 Vermont electric utilities.[49]

Building new generation and new transmission, along with crafting PPAs, are subject to regulation from state, provincial, and federal agencies. Within these regulatory processes, projects and contracts face challenges from various stakeholders. Additionally, hydropower projects face competition from other forms of electric generation. For example, a public utility commission might be more inclined to approve a new natural gas-fired power plant because it would save ratepayers money relative to other forms of generation **(Figure 3)**. In some instances, a state RPS might favor other sources of generation, namely wind or solar power. Additionally, states may prefer to develop their own in-state generation because of the jobs that in-state electric power projects bring.[50]

KEEYASK (ISD 2019/20)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	80	271	378	371	366	361	355	349	343	338	330	326	305	297	287
OM&A Costs	-	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15
Depreciation	-	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90
Capital Tax	8	12	17	23	28	31	32	32	31	31	30	30	29	29	29	28	28	27	27	26
Water Rentals	-	-	-	-	-	2	13	15	15	15	15	15	15	15	15	15	15	15	15	15
	8	12	17	23	28	124	395	528	521	517	511	505	498	492	486	479	473	452	443	434

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	11	20	20	20	19	19	18	18	18	17	17	16	15	15
OM&A Costs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	-	-	-	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	1	2	17	28	27	27	27	26	26	26	25	25	24	23	23	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	34	48	46	44	42	41	39	37	35	34	32	29	27	25
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	-	16	16	15	15	15	15	14	14	13	13	17	17	17	16
Capital Tax	0	0	0	1	2	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	0	1	2	3	68	87	84	82	80	78	76	74	72	69	72	69	66	64

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Pointe du Bois Generating Station
For the 2014/15 Power Resource Plan the Pointe du Bois powerhouse rebuild is assumed for 2039/40. This is a 10 year deferral from the 2013/14 Power Resource Plan. A review of the life extension of the Pointe de Bois powerhouse has been initiated.

4.2 Committed Resources

Consistent with Provincial approvals stemming from the Needs For and Alternatives To (NFAT) process and environmental regulatory approvals, Keeyask G.S. and a new 500kV US interconnection are included as committed resources.

Keeyask Generating Station
The Keeyask G.S. will be located upstream of the Kettle G.S. on the lower Nelson River with 7 units having a maximum rated total power capacity of 695 MW, which occurs when Stephens Lake is drawn down. There will be a net addition of 630 MW to Manitoba Hydro's Integrated Power System once the Keeyask G.S. is added.

Construction of the Keeyask Generation Project began in July 2014, following receipt of all required provincial and federal licenses, authorizations and permits. The first unit is planned to be in-service in 2019 and with the last unit in-service by the fall of 2022.

4.3 Resources in Regulatory Approval Process

US Interconnection
The new 500 kV US interconnection is capable of 698 MW for import and 883 MW for export. The new interconnection is assumed to have an in-service date of June 1, 2020 which is coincident with the start of the MH–MP250 MW Sale Agreements. The new interconnection received approval through the 2013/14 Need For and Alternatives To (NFAT) process but requires several other Canadian and US regulatory approvals which are expected to be received by late 2016.

4.4 Power Purchases from Manitoba Generators

Wind Generation
Manitoba Hydro has power purchase agreements (PPAs) with three wind producers, St. Leon Energy LP, Algonquin Power, and Pattern Energy Group. These PPA's provide Manitoba Hydro with 771 GW.h of dependable energy on an annual basis. Wind generation is not assigned a capacity value for the purposes of meeting winter peak load as it is not assured to be available at the time of system peak. For planning purposes, contracted purchases of wind generation are assumed to be renewed using the same terms and conditions after the expiration of the current contracts and to extend through to the end of the study period.

Section:	Tab 4: Appendix 11.35 & 11.36	Page No.:	
Topic:	Capital Expenditures		
Subtopic:	Construction work in progress		
Issue:	Detail of Capital Costs		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's total capital expenditures have shown material changes and are a major driver behind requested rate increases.

QUESTION:

Please provide an update to PUB/MH I-93 (a) from the 2012 GRA to include CEF12, CEF13 and CEF14. Please total the schedule.

RATIONALE FOR QUESTION:

This Information Request seeks background information on capital cost escalation.

RESPONSE:

Please see the following table.

Progression of Project Costs in $ M												
	CEF-03	CEF-04	CEF-05	CEF-06	CEF-07	CEF-08	CEF-09	CEF-10	CEF-11-2	CEF-12	CEF-13	CEF-14
Wuskwatim G.S.		846	935	1,094	1,275	1,275	1,275	1,275	1,375	1,449	1,449	1,449
Wuskwatim Transmission		199	200	257	320	316	316	291	298	323	320	320*
Wuskwatim Total Project	988	1,045	1,135	1,351	1,595	1,591	1,591	1,566	1,673	1,771	1,768	1,768
Herblet Lake Transmission	57	55	54	54	95	93	93	75	75	77	76	76*
Bipole III	360(E)	388(E)	1,880	1,880	2,248	2,248	2,248	3,280	3,280	3,280	3,280	4,653
Riel C.S.	96	101	103	103	105	268	268	268	268	268	330	330
Kelsey G.S.	121	121	166	166	184	190	190	302	302	302	302	340
Kettle G.S.		61	61	61	61	76	76	166	166	166	166	192
Pointe du Bois Spillway							318	398	398	560	560	575
Pointe du Bois Trans.					83	86	86	86	86	86	114	114
Pointe du Bois Rebuild	421	288	692	834	818	818		1,538	1,538	1,538	1,538	1,852
Slave Falls G.S.				179	192	198	198	223	230	230	126	126
Conawapa G.S.		4,050	4,516	4,978	4,978	4,978	6,325	7,771	7,771	10,192	10,492	397
Keeyask G.S.						3,700	4,592	5,637	5,637	6,220	6,220	6,496
500 KV Dorsey U.S. Border						205	205	205	205	205	350	350
Total	2,043	7,154	9,742	10,957	11,954	16,042	17,781	23,081	23,302	26,665	27,091	19,038

*Wuskwatim Transmission and Herblet Lake Transmission Projects are in-service and have no further capital spending. These projects were removed from CEF14 but included in this table for completeness.

KEEYASK (ISD 2019/20)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	80	271	378	371	366	361	355	349	343	338	330	326	305	297	287
OM&A Costs	-	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15
Depreciation	-	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90
Capital Tax	8	12	17	23	28	31	32	32	31	31	30	30	29	29	29	28	28	27	27	26
Water Rentals	-	-	-	-	-	2	13	15	15	15	15	15	15	15	15	15	15	15	15	15
	8	12	17	23	28	124	395	528	521	517	511	505	498	492	486	479	473	452	443	434

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	11	20	20	20	19	19	18	18	18	17	17	16	15	15
OM&A Costs	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	-	-	-	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	1	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	1	2	17	28	27	27	27	26	26	26	25	25	24	23	23	22

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Finance Expense	-	-	-	-	-	-	34	48	46	44	42	41	39	37	35	34	32	29	27	25
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	-	16	16	15	15	15	15	14	14	13	13	17	17	17	16
Capital Tax	0	0	0	1	2	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	0	1	2	3	68	87	84	82	80	78	76	74	72	69	72	69	66	64

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6.0 ELECTRICITY SUPPLY

Manitoba Hydro's 2014/15 Power Resource Plan indicates new generation is required by 2038/39 to meet the current projection of Manitoba load requirements under dependable energy conditions. New capacity resources are forecast to be required by 2037/38.

The following resources contribute to the ability to meet future Manitoba energy and capacity requirements.

	MW	Dependable GW.h	In-Service Date
HVDC Bipole III Line & 2300 MW of Converter Capability	80	177	2018/19
Keeyask	695	3 000	2019/20
Demand Side Management Program			
Planned Additional	582	2 797	By 2028/29

For IFF14 forecast purposes, it is assumed that Conawapa has been suspended and replaced with a gas turbine required in 2037/38 to meet firm capacity requirements. While the majority of planning and licensing activities on Conawapa have been suspended, Manitoba Hydro continues to pursue dependable firm export sales based on the earliest possible in-service date of Conawapa in 2029/30 and will re-evaluate the business case (currently anticipated by the Fall of 2016).

Section:	Tab 4 Appendix 4.1	Page No.:	CEF 14 Pg. 3
Topic:	Capital Expenditure Forecast		
Subtopic:	HVDC – System Capabilities		
Issue:	Bipole I,II & III Utilization		

PREAMBLE TO IR (IF ANY):

NFAT PUB/MH I-042(a) Revised calculates the current and future energy usage of the Bipole system.

QUESTION:

Refile NFAT IR PUB/MH I-042 (a) Revised adding to each table the online percentage capacity utilization of total hydraulic generation and percentage capacity utilization of the total HVDC transmission system.

RATIONALE FOR QUESTION:

This IR explores the future usage of the Bipole system.

RESPONSE:

The following provides a reposting of tables from NFAT IR PUB/MH I-042(a) with online percentage capacity utilization of total existing and committed generation and percentage capacity utilization of the total HVDC transmission system.

Bipoles I and II – 2013						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
Kettle	1220	4750	7010	8960	100%	Bipole I	14140 GW.h	1854 MW	309 MW	83%	480	850
Long	1010	3890	5970	7830	100%							
Spruce	1340	5140	7500	9900	100%	Bipole II	15260 GW.h	2000 MW	500 MW	75%	480	850
Limestone												
Total	3570	13780	20480	26690	100%	Total	29400 GW.h	3854 MW	500 MW	87%	960	1700

After Bipole III – 2019 without Keeyask						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
						Bipole I	12540 GW.h	1854 MW	309 MW	83%	250	440
Kettle	1220	4750	7010	8960	100%							
Long Spruce	1010	3890	5970	7830	100%	Bipole II	13520 GW.h	2000 MW	500 MW	75%	250	440
Limestone	1340	5140	7500	9900	100%							
						Bipole III	13520 GW.h	2000 MW	500 MW	75%	250	440
Total	3570	13780	20480	26690	100%	Limit	41610 GW.h	5854 MW	1104 MW	81%	750	1320

5279 MW

After Bipole III – 2022 with Keeyask						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
Keeyask	630	3000	4400	4740	100%	Bipole I	12540 GW.h	1854 MW	309 MW	83%	310	550
Kettle	1220	4750	7010	8960	100%							
Long Spruce	1010	3890	5970	7830	100%	Bipole II	13520 GW.h	2000 MW	500 MW	75%	310	550
Limestone	1340	5140	7500	9900	100%							
						Bipole III	13520 GW.h	2000 MW	500 MW	75%	310	550
Total	4200	16780	24880	31430	100%	Limit	41610 GW.h	5854 MW	1104 MW	81%	930	1650

+ 1654 MW

w/o Conawapa

0

with Conawapa
1300 MW

Section:	Tab 4 Appendix 4.1	Page No.:	CEF 14 Pg. 3
Topic:	Capital Expenditure Forecast		
Subtopic:	HVDC – System Capabilities		
Issue:	Bipole I,II & III Utilization		

PREAMBLE TO IR (IF ANY):

NFAT PUB/MH I-042(a) Revised calculates the current and future energy usage of the Bipole system.

QUESTION:

Explain why the addition of Conawapa G.S. in 2029 would reduce the maximum HVDC limit from 48,900 GWh to 46,270 GWh.

RATIONALE FOR QUESTION:

This IR explores the future usage of the Bipole system.

RESPONSE:

The maximum HVDC limit of 48900 GWh reported in NFAT PUB/MH I-042(a) Revised is an unobtainable maximum. The maximum should have been reported as 41600 GWhs which reflects a maximum HVDC loading of 4750MW. Having a single, close coupled HVDC system is limited to a maximum of 4750 MW allowable single point injection into the southern AC system. Having more than 4750 MW of generation on the lower Nelson requires splitting the HVDC system into two, electrically independent systems to ensure that neither system is greater than 4750 MW. The net result of splitting the HVDC system is an increase in maximum overall limit to 5279 MW (46270 GW.h).

Section:	Tab 4, App 4.1	Page No.:	PUB/MH I-66a
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

Please calculate MH's maximum annual hydraulic generation output from the Lower Nelson River generating stations and indicate the percentage of total nameplate capacity that this constitutes.

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

It is unclear if this question is seeking information on power (MW) or energy (GWh) output as a percentage of nameplate capacity.

There have been instances where the total hourly output from the Lower Nelson River stations has been over 100% of nameplate capacity. For example, on December 2, 2000 hourly total Lower Nelson River output was recorded to be 3,596 MW or 101.2% of station capacity values provided in PUB/MH-I-66a.

Maximum actual fiscal year total output from the Lower Nelson River stations occurred in 2005/06 when the gross output was 27,323 GWh. Using the Lower Nelson River station capacity values provided in PUB/MH-I-66a, this translates to a capacity factor of 87%.

Section:	Tab 4, App 4.1	Page No.:	PUB/MH I-66(a)
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

Please indicate expected annual HVDC losses (GWh) under maximum hydraulic generation conditions for the three Lower Nelson plants.

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

The expected annual HVDC losses are not available for the three plants as the losses are dependent on the total load transmitted by the HVDC system and are independent of where the generation occurs.

The year with the maximum hydraulic generating conditions for the lower Nelson plants was 2005/06 in which 27,323 GW.h (average load of 3119 MW) was generated. The estimated HVDC losses for the 2005/06 year totaled 2215 GW.h (average estimated loss of 253 MW). The HVDC losses during the maximum experienced hourly loading of 3598.6 MW (in 2000/01) was 315.6 MW.

Section:	Tab 4, App 4.1	Page No.:	PUB/MH I-66(a)
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

For 2013/14, Q3 & Q4, indicate the 5x16 Lower Nelson River generating stations' monthly energy output (GWh) that was achieved.

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

2013/14 Q3 and Q4 monthly total 5x16 Lower Nelson River generation is provided below.

Month	Lower Nelson River 5x16 Generation (GWh)
Oct-13	1141
Nov-13	1045
Dec-13	1115
Jan-14	1156
Feb-14	974
Mar-14	1008

Section:	Tab 4, App 4.1	Page No.:	PUB/MH I-66(a)
Topic:	Power Resource Plan		
Subtopic:	HVDC System Capabilities		
Issue:	Bipole I, II & III utilization		

PREAMBLE TO IR (IF ANY):

PUB/MH I-66(a) does not fully address the percent on-line time of MH's Lower Nelson River hydraulic generation.

QUESTION:

In 2013/14, what was the capacity factor of the Bipole I & II HVDC systems?

RATIONALE FOR QUESTION:

This question seeks information that was expected to be filed as part of PUB/MH I-66(a).

RESPONSE:

The total annual lower Nelson generation during 2013/14 was 24453 GWh or 2791 MW averaged over 8760 hours of the year. The maximum capacity of the Bipoles without reserve is 3854 MW, and as such the capacity factor based on this rating would be 72.4%**.**

NEEDS FOR AND ALTERNATIVES TO (NFAT)

Manitoba Hydro's Response to PUB Question #1

Ref.: PUB/MH II-402, 2005/06 Winter & Summer

1. Please confirm that this is MH's most recent filing of the top 50 winter and top 50 summer peak hours of generation.

2. Provide the average domestic (common bus) and export transmission losses for the 50 top winter and for the 50 top summer loads.

Ref.: PUB/MH II-402, 2005/06 Winter & Summer
Attached Tables (PUB/MH II-402, pp. 2 & 3 of 3 (amended to include incremental loss calculations))

3. Verify or re-calculate the incremental shares (load-squared basis) of the transmission losses going to domestic/common bus firstly and then the exports secondly.

Transmission Losses Incremental Winter Averages		
Domestic	**Export**	**Overall**
5.2%	**12.55%**	**8.09%**
Incrementally Summer Averages		
5.8%	**15.7%**	**9.59%**

4. Provide a monthly tabulation of MH's peak (5x16) and off-peak during both winter and summer energy loads, and HVDC & AC transmission losses for 2005/06 and 2012/13.

Response:

1. Manitoba Hydro filed the top 50 winter and top 50 summer peak hours of generation for the years 2005/06, 2008/09 and 2010/11 in PUB/MH I-041a. The 2005/06 table was refiled in PUB/MH II-402 to include the total system loss calculation for each hour. Therefore, it is confirmed that PUB/MH II-402 is the most recent filing of the top 50 hours of generation for 2005/06.

2. Due to limited time available, statistics for the top 50 summer and winter average domestic (common bus) loads could not be compiled. Manitoba Hydro does not

consider the requested information germane to the analysis of the Preferred Development Plan.

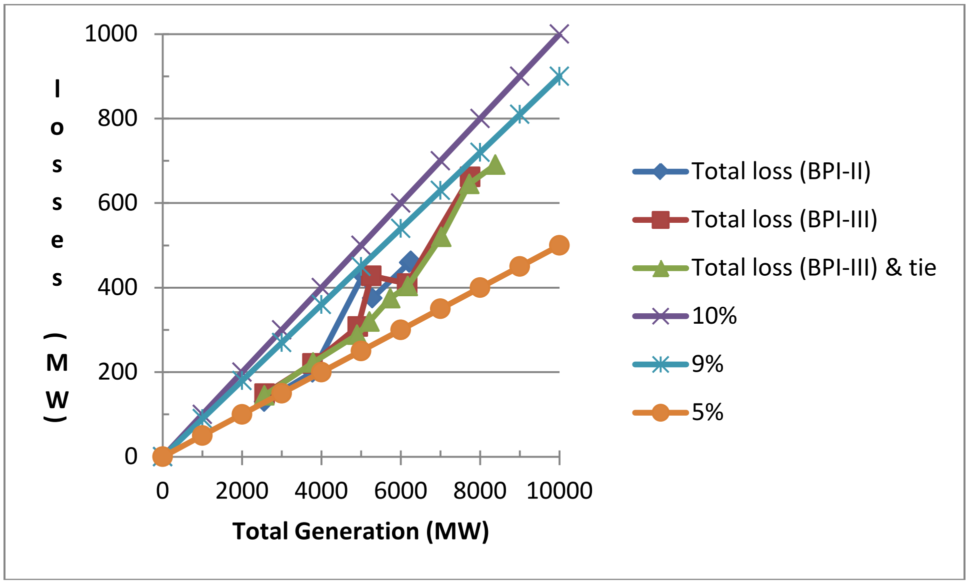
3. The accurate calculation and tracking of system losses and allocation to various load classes including exports is a complex engineering calculation. For this reason Manitoba Hydro has adopted a method for accounting purposes which determines total losses required to supply total load and assigns the same hourly loss/gain ratio to all load classes (residential, commercial, industrial, exports and imports).

With the exception of load flow studies based on actual hourly system data, Manitoba Hydro does not endorse other incremental loss accounting methodologies including the one requested in this Undertaking. These other methodologies have no technical justification for being more accurate or appropriate than the Manitoba Hydro average loss accounting method as they ignore:

a) That exports and imports can be scheduled simultaneously at any time during the day,
b) That all Manitoba Hydro generators can be the source of exports or can be reduced by imports,
c) That the marginal MW of load being served by Manitoba generation is not always an export MW,
d) That Manitoba Hydro is not the only entity using its transmission system to export or import from Manitoba as access to Manitoba Hydro's transmission system is available to all as provided under the MH Transmission Tariff,
e) That loop flows from the US increase losses in Manitoba and are beyond Manitoba Hydro's control. Loop flows are routine and aren't the result of Manitoba Hydro exports activities. However Manitoba Hydro, as a Balancing Authority, must supply this loop flow. In the winter case studied below, average loop flow was 136 MW or about 9% of total exports and for the summer case it was 126 MW or about 6% of total exports.
f) That a portion of the Manitoba load is served on an interruptible basis equivalent to exports.

An example of the potential range of losses calculated using an accurate power system model is given in the figure below. The model data used were from the same twenty-one power flow cases provided to Power Engineers[1] with HVdc station losses[2] also included.

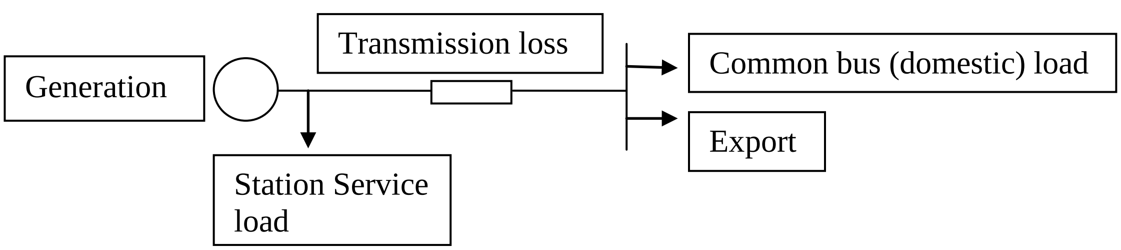
[1] Page 16-19, Power Engineers report to the Public Utilities Board, Jan. 13, 2014.
[2] See PUB/MH II-327b and PUB/MH II-328a



The expected losses ranged between five and nine percent of total generation. In the NFAT analysis Manitoba Hydro has made a conservative assumption of 10%. This value is reasonable for both the existing system and the future system including Bipole III and the new 500 kV tie to the U.S.

However as requested in the Undertaking Manitoba Hydro has calculated incremental losses below using the alternative methodology requested although as explained above it is no more accurate than the Manitoba Hydro practice.

A simple representation of losses in Manitoba can be shown by the following diagram.



Assuming transmission loss is represented by an equivalent resistance (R), then $I_{cb}^2R=Loss_{cb}$. Transmission losses associated with supplying the common bus load is ($Loss_{cb}$). Similar formulas can be derived for transmission losses associated with exports ($Loss_{export}$) and total losses ($Loss_{total}$).

$$I_{cb}^2R=Loss_{cb}$$
$$(I_{cb} + I_{export})^2R=Loss_{total}$$

Substitute $I_{cb} = Load_{cb}/V$ and $I_{export} = Load_{export}/V$ into the above.

$$Loss_{cb}=Loss_{total} * (Load_{cb}^2/(Load_{cb}+Load_{export})^2$$

The above formula assumes common bus (domestic) load is supplied first and exports are supplied next. As mentioned above, this is a hypothetical situation as exports and imports can be scheduled at any time during the day. The results of applying this loss formula are shown in the table below.

Case	A: Load at common bus (MW)	B: MB Exports (MW)	C: Total loss (MW)	D: $A^2/(A+B)^2$ *C Incremental Load losses (MW)	Domestic losses (percent of load at common bus)	E: C-D Incremental Export losses (MW)	Export losses (percent of MB exports)	Total losses (percent of generation)
05/06 Winter	3073	1557	397.6	175	5.70%	222	14.3%	8.1%
05/06 Summer	2365	2091	467.2	132	5.56%	335	16.0%	9.6%

4. Due to limited time available, monthly tabulation of the requested loads and losses could not be compiled. Please refer to PUB/MH II-464b for typical summer and winter peak losses that were analyzed for each of the last 3 years. Total losses, including a breakdown between HVDC and AC losses are given. PUB/MH II-330c can be referred to for an analysis of the losses that occur during various periods including:

- 5×16 summer (peak)
- 5×8 summer (night-time)
- 2×16 summer (weekends)
- 5×16 winter (peak)
- 5×8 winter (night-time)
- 2×16 winter(weekends)

NEEDS FOR AND ALTERNATIVES TO (NFAT)

Manitoba Hydro's Response to PUB Question #2

Ref. PUB/MH I-042a Revised

Confirm the following table is a reasonable extraction from PUB/MH I-042a revised of the incremental HVDC losses for dependable hydraulic energy and for average hydraulic energy minus dependable energy.

Provide another column on each of the four tables in PUB/MH I-042a revised showing the HVDC losses at maximum hydraulic generation.

HVDC Incremental Transmission Losses (GWh) Ref.: PUB/MH I-042a				
		Dependable	Average minus Dependable	Incremental Losses Maximum minus Average
2013	Bipole I&II	7% (960/13780)	11% (740/6700)	
2019	Bipoles I/II/III w/o Keeyask	5.44% (750/13780)	8.51% (570/6700)	
2022	Bipoles I/II/III with Keeyask	5.54% (930/16780)	8.89% (720/8100)	
2029	Bipoles I/II/III with Keeyask & Conawapa	6.63% (930/16780)	10.91% (1095/10750)	

Confirm that domestic load has priority claim on dependable hydraulic generation and that only excess hydraulic generation above dependable is available for export.

Confirm the incremental losses do not include transmission losses from Dorsey or Riel to border and provide those losses under the three flow situations.

Response:

It is not confirmed that the proposed table is a reasonable extraction from PUB/MH I-042a Revised. Expected Losses and Generation are as follows:

HVDC Incremental Transmission Losses (GWh)				
		Dependable Loss/Generation (GW.h)	Average Loss/Generation (GW.h)	Maximum Loss/Generation (GW.h)
2013	Bipole I&II	6.97% 960/13780	8.30% 1700/20480	8.45% 2254/26690
2019	Bipoles I/II/III w/o Keeyask	5.44% 750/13780	6.44% 1320/20480	6.55% 1747/26690
2022	Bipoles I/II/III with Keeyask	5.54% 930/16780	6.63% 1650/24880	7.06% 2218/31430
2029	Bipoles I/II/III with Keeyask & Conawapa	6.63% 1410/21260	7.83% 2505/32010	8.34% 3434/41190

		HVDC Incremental Transmission Losses (GWh)			
		Dependable Loss/Generation (GW.h)	Average minus Dependable (GW.h)	Maximum minus Average (GW.h)	Peak Losses (MW)
2013	Bipole I&II	6.97% 960/13780	11.04% 740/6700	8.92% 554/6210	8.69% 308.9/3554
2019	Bipoles I/II/III w/o Keeyask	5.44% 750/13780	8.51% 570/6700	6.88% 427/6210	6.56% 233.2/3554
2022	Bipoles I/II/III with Keeyask	5.54% 930/16780	8.89% 720/8100	9.64% 561/5820	7.22% 305.2/4230
2029	Bipoles I/II/III with Keeyask & Conawapa	6.63% 1410/21260	10.19% 1095/10750	10.12% 929/9180	8.71% 486.2/5580

Dependable Conditions reflect annual generation and associated HVDC losses estimated for the dependable flow condition.

Average Conditions reflect the average annual generation and associated HVDC losses under the range of flow conditions.

Maximum Conditions reflect the annual generation and associated HVDC losses under the maximum historic flow condition.

Peak Losses reflects the capacity and associated losses under maximum HVDC loading conditions.

It is not confirmed that domestic load has priority claim on dependable hydraulic generation. Domestic load has a priority claim on the combined dependable energy from thermal, import, purchases and hydraulic generation. Hydraulic generation credits would be assigned as designated under export contracts.

It is confirmed that the above losses do not reflect any losses from Dorsey or Riel to the border. It is not feasible to determine what component of the HVDC generation would be transmitted to the US border from the above information, as losses on the AC system will depend on the level of generation available from generators connected to the AC system, as well as load distribution across the province. Losses on the export interface (to the border) are currently 47 MW when fully loaded at 2175 MW. For the same load (2175 MW) with a new 750 MW interconnection, losses will reduce to 31 MW. When the new interface is fully loaded (2975 MW), losses will increase, back to 52 MW.

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CAPITAL EXPENDITURE FORECAST (CEF13)
(in millions of dollars)

	Total Project Cost	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	44.8	23.8	12.1	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	2.3	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	0.3	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	350.1	471.0	639.3	865.1	1 111.4	942.3	789.5	282.4	129.3	-	5 580.2
Conawapa - Generation	10 491.5	69.8	70.1	125.9	99.4	240.6	308.1	387.5	432.5	1 061.6	1 722.1	4 517.5
Kelsey Improvements & Upgrades	301.7	16.0	2.2	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	3.2	7.7	23.7	17.3	1.0	31.7	29.5	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	260.5	125.3	5.5	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	12.7	8.6	12.3	21.9	7.4	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	-	-	-	-	-	-	-	-	0.5	2.2	2.7
Gillam Redevelopment and Expansion Program (GREP)	366.5	-	27.0	30.2	30.5	29.5	27.9	26.3	29.1	28.7	26.8	256.0
Bipole III - Transmission Line	1 259.9	66.2	265.9	381.9	263.7	195.2	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	179.0	262.6	493.2	410.2	181.5	127.4	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	28.8	63.5	46.2	37.7	8.5	-	-	-	-	-	184.6
Community Development Initiative	60.8	53.9	2.2	2.0	1.8	0.9	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	74.1	40.8	0.7	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	0.0	10.8	8.9	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	0.4	3.8	29.7	101.1	58.7	63.5	91.7	0.1	-	-	349.0
St. Joseph Wind Transmission	10.0	0.0	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	28.1	25.3	24.6	23.9	22.6	21.7	19.9	18.9	18.8	18.7	222.4
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	-	2.8	33.0	33.6	34.3	103.7
Additional North South Transmission	475.0	-	-	-	-	-	-	-	4.1	4.4	51.6	60.2
Target Adjustment (Cost Flow)	NA	(119.0)	(33.9)	(46.0)	(8.2)	0.7	33.6	20.9	56.8	(42.0)	(62.1)	(199.3)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 071.1**	**1 376.5**	**1 790.2**	**1 864.4**	**1 858.1**	**1 556.0**	**1 368.1**	**856.8**	**1 234.8**	**1 793.6**	**14 769.6**

CAPITAL EXPENDITURE FORECAST (CEF13)

(in millions of dollars)

	Total Project Cost	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	80.7
Wuskwatim - Transmission	319.8	-	-	-	-	-	-	-	-	-	-	2.3
Herblet Lake - The Pas 230kV Transmission	76.4	-	-	-	-	-	-	-	-	-	-	0.3
Keeyask - Generation	6 220.1	-	-	-	-	-	-	-	-	-	-	5 580.2
Conawapa - Generation	10 491.5	1 700.2	1 428.7	1 228.1	920.1	371.2	65.0	-	-	-	-	10 230.8
Kelsey Improvements & Upgrades	301.7	-	-	-	-	-	-	-	-	-	-	18.2
Kettle Improvements & Upgrades	165.7	-	-	-	-	-	-	-	-	-	-	114.2
Pointe du Bois Spillway Replacement	559.6	-	-	-	-	-	-	-	-	-	-	391.3
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	62.9
Pointe du Bois Powerhouse Rebuild	1 538.3	16.0	37.8	90.7	157.8	245.0	403.9	312.7	216.2	55.6	-	1 538.3
Gillam Redevelopment and Expansion Program (GREP)	366.5	32.3	32.1	34.0	11.9	-	-	-	-	-	-	366.5
Bipole III - Transmission Line	1 259.9	-	-	-	-	-	-	-	-	-	-	1 172.9
Bipole III - Converter Stations	1 828.5	-	-	-	-	-	-	-	-	-	-	1 653.9
Bipole III - Collector Lines	191.4	-	-	-	-	-	-	-	-	-	-	184.6
Community Development Initiative	60.8	-	-	-	-	-	-	-	-	-	-	60.8
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	115.5
Firm Import Upgrades	19.9	-	-	-	-	-	-	-	-	-	-	19.7
Dorsey - US Border New 500kV Transmission Line	350.3	-	-	-	-	-	-	-	-	-	-	349.0
St. Joseph Wind Transmission	10.0	-	-	-	-	-	-	-	-	-	-	0.0
Demand Side Management	NA	19.1	18.7	17.9	16.2	16.0	16.3	16.6	16.9	17.3	17.6	395.1
Generating Station Improvements & Upgrades	NA	35.0	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	373.8
Additional North South Transmission	475.0	29.8	49.9	85.7	116.8	132.7	-	-	-	-	-	475.0
Target Adjustment (Cost Flow)	NA	(3.9)	22.6	13.3	23.8	49.5	34.0	20.2	11.1	17.1	6.2	(5.5)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 828.5**	**1 625.5**	**1 506.1**	**1 291.6**	**846.5**	**540.2**	**358.9**	**258.7**	**105.2**	**49.6**	**23 180.3**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	10 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	40.5	12.9	14.7	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	776.3	676.3	962.2	1 351.3	927.9	616.5	208.6	55.2	4.5	0.1	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	1.9	4.7	9.3	6.8	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	43.4	31.4	21.0	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	14.1	9.1	12.9	1.3	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	6.6	23.5	24.6	22.0	31.7	29.5	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	114.1	51.6	3.8	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	15.8	17.1	13.8	4.3	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	-	-	-	-	-
Gillam Redevelopment and Expansion Program (GREP)	266.5	20.0	22.4	22.8	21.8	20.2	18.6	21.3	20.9	19.1	24.6	211.6
Bipole III - Transmission Line	1 655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	36.4	5.6	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	7.0	32.7	99.6	59.5	65.7	48.1	35.4	-	-	-	348.0
Demand Side Management	NA	51.8	59.2	76.6	83.9	93.7	78.2	72.5	60.8	50.0	49.6	676.2
Generating Station Improvements & Upgrades	NA	-	-	-	-	-	2.8	33.0	33.6	34.3	35.0	138.6
Target Adjustment (Cost Flow)	NA	(161.3)	(51.4)	(61.1)	(12.7)	116.3	71.9	50.9	25.6	8.8	0.7	(12.2)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**1 451.7**	**1 913.9**	**2 463.5**	**2 577.8**	**1 530.9**	**884.0**	**426.2**	**196.1**	**116.6**	**110.0**	**11 670.7**

CAPITAL EXPENDITURE FORECAST (CEF14)
(in millions of dollars)

	Total Project Cost	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	20 Year Total
Major New Generation & Transmission												
Wuskwatim - Generation	1 448.6	-	-	-	-	-	-	-	-	-	-	68.1
Keeyask - Generation	6 496.1	-	-	-	-	-	-	-	-	-	-	5 578.8
Grand Rapids Hatchery Upgrade & Expansion	23.5	-	-	-	-	-	-	-	-	-	-	22.6
Conawapa - Generation	397.0	-	-	-	-	-	-	-	-	-	-	95.8
Kelsey Improvements & Upgrades	340.4	-	-	-	-	-	-	-	-	-	-	37.3
Kettle Improvements & Upgrades	191.6	-	-	-	-	-	-	-	-	-	-	137.9
Pointe du Bois Spillway Replacement	574.8	-	-	-	-	-	-	-	-	-	-	169.5
Pointe du Bois - Transmission	114.3	-	-	-	-	-	-	-	-	-	-	50.9
Pointe du Bois Powerhouse Rebuild	1 852.2	-	-	-	-	-	-	0.6	2.6	19.1	45.3	67.6
Gillam Redevelopment and Expansion Program (GREP)	266.5	24.4	26.3	4.2	-	-	-	-	-	-	-	266.5
Bipole III - Transmission Line	1 655.4	-	-	-	-	-	-	-	-	-	-	1 514.0
Bipole III - Converter Stations	2 675.1	-	-	-	-	-	-	-	-	-	-	2 356.3
Bipole III - Collector Lines	260.2	-	-	-	-	-	-	-	-	-	-	227.0
Bipole III - Community Development Initiative	62.0	-	-	-	-	-	-	-	-	-	-	8.1
Riel 230/500kV Station	329.9	-	-	-	-	-	-	-	-	-	-	42.0
Manitoba-Minnesota Transmission Project	350.3	-	-	-	-	-	-	-	-	-	-	348.0
Demand Side Management	NA	47.5	48.3	47.2	47.2	48.3	50.2	52.2	54.4	56.6	58.9	1 186.9
Generating Station Improvements & Upgrades	NA	35.7	36.4	45.0	32.2	21.1	9.4	14.4	15.2	25.8	79.3	453.2
Target Adjustment (Cost Flow)	NA	0.2	(0.3)	1.4	1.8	1.2	1.1	(0.6)	(0.6)	(3.0)	(8.5)	(19.4)
MAJOR NEW GENERATION & TRANSMISSION TOTAL		**107.8**	**110.7**	**97.8**	**81.3**	**70.5**	**60.7**	**66.5**	**71.6**	**98.4**	**175.0**	**12 611.1**

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Manitoba Hydro
October 19, 2012

Transmission Asset Condition Assessment Project Findings

KINECTRICS

Experts in Asset Management

Asset Grouping Considered

KINECTRICS

All assets within the scope of this project are part of the Manitoba Hydro's transmission asset base.

- Power Transformers (115 kV, 138 kV, 230 kV)
- Circuit Breakers (Air Blast, SF6, Bulk Oil, Min Oil)
- Wood Poles
- Wood SPAR arms
- Conductor
- Steele structures

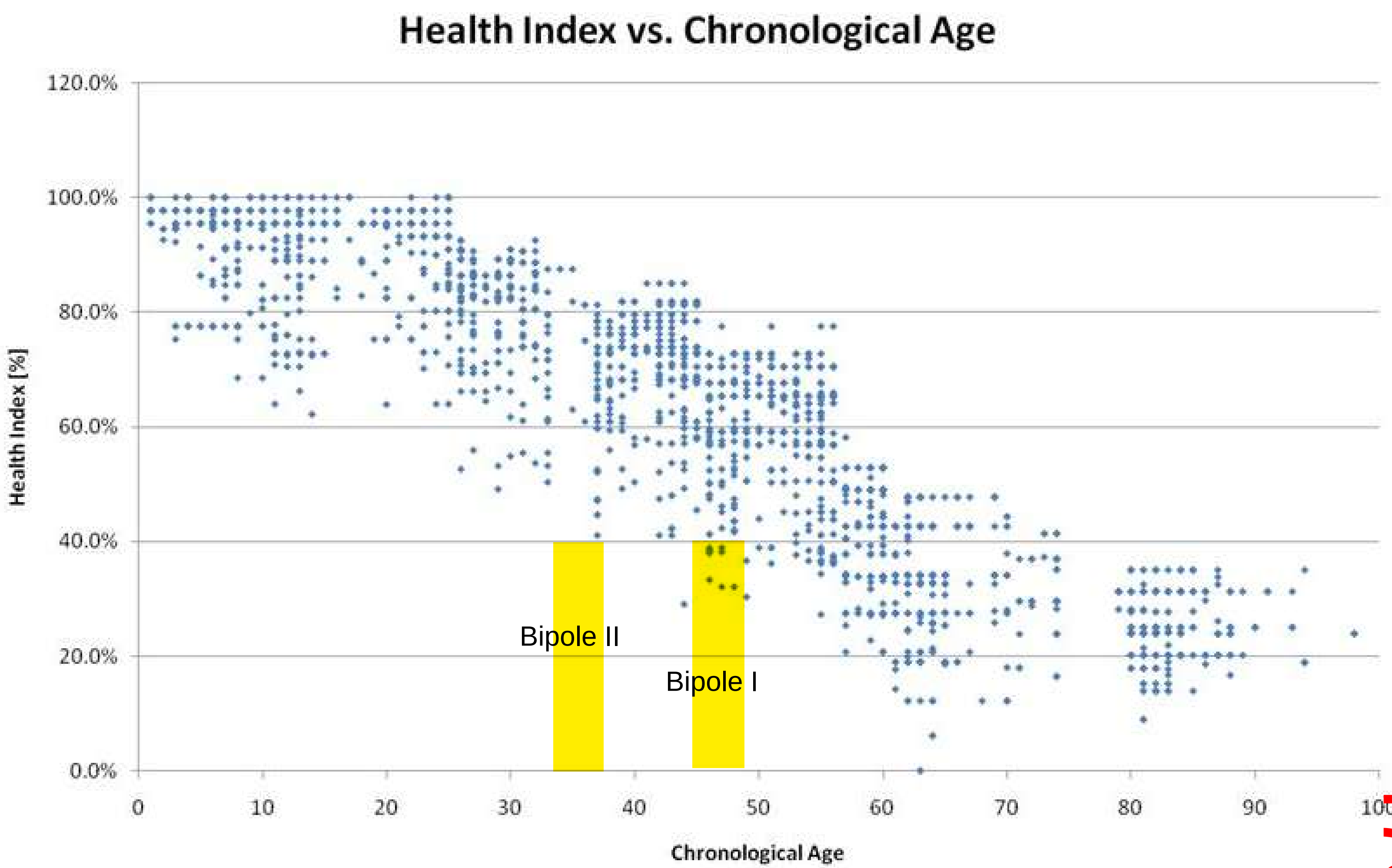
Assessment Performed

KINECTRICS

Assets Grouping	ACA	RA	CRS	Prioritized List of Assets	Field Testing	Recommendations
Transformers	√	√	√	√		√
Circuit Breakers	√	√	√	√		√
Wood Poles	√	√	√			√
SPAR arms	√	√	√			√
Conductor					√	√
Steel Structures						√

Asset: Condition Assessment
RA: Risk Assessment
CRS: Capital Replacement Strategy

Health Index vs Age



Recommended Condition Data Improvements - 1

KINECTRICS

- In addition to the condition data being collected for transformers, tap changers, circuit breakers and poles start collecting failure data, i.e. age when assets are replaced, in order to establish a Manitoba Hydro-specific failure curves (a very good start already made with transformers, MH should continue refining and accumulating similar data).
- Institute an annual program for testing transmission lines phase conductors, starting with critical locations, using a combination of laboratory and in-situ non-intrusive testing methodologies. Health Index and prioritized replacement strategy for conductors could then be developed by extrapolating the sample results on a larger population of conductors.

Recommended Condition Data Improvements - 2

KINECTRICS

- Start collecting information for creating a failure curve for SPAR arms. Age will then be used in conjunction with this failure curve to estimate number of units expected to be replaced annually.
- Start collecting condition data on steel structures by initiating a program of steel tower climbing inspections and footings assessments using ultra-sound methodology
- Use multi-purpose software to unable:

  a) storage of condition input data for multiple years,

  b) updating results based on the condition data changes

  c) analyzing options to deal with assets "flagged for action" and

  d) prioritizing the required investments portfolio

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TRANSMISSION

Asset Condition Assessment (ACA) Methodology

Background:

The Transmission Business Unit (BU) began its asset condition assessments in 2012 by hiring a third party consultant with expertise in the development of condition assessment methodologies for utility grade high voltage (HV) equipment. This third party consultant worked with Transmission's subject matter experts to provide asset condition assessment methodologies and statistical failure models for transmission system station transformers, tap changers, breakers and transmission wood poles structures. The remaining Transmission asset condition assessment methodologies presented in this report, while similar in approach, were developed by the Transmission Asset Strategies group in consultation with subject matter experts across the Business Unit. This section describes these methodologies.

Where an asset has a statistical failure model available, the model has been incorporated into the AHI scoring methodology. The purpose of this is to increase the extent to which the AHI reflects the likelihood of failure. Statistical failure models were available for breakers, transformers and transmission line wood pole structures. These models were provided by the above mentioned consultant and were based on the consultant's industry failure curves, on subject matter expert input and limited failure data provided by Manitoba Hydro and on the consultant's proprietary methodology to link condition parameter scores to probability of failure.

Transmission will continue to evolve its existing condition assessment methodologies as it gains experience with these models and to develop and implement new condition assessment models for asset classes such as instrument transformers and equipment bushings, to the extent that there's a positive business case to do so.

The boundaries between the different classifications of the AHI Score (i.e. Very Good, Good, Fair, Poor and Very Poor) were determined using the classification definitions provided in Section 4 of the report.

Transmission System Steel Structures/Grillage

Due to the nature of steel structures/grillage, their associated foundations combined with available asset data, the methodology differs from that used by the third party consultant. Age was one of two characteristics used for condition assessment of transmission structures, excluding wood structures, and accounts for 20 percent of the condition index. Actual asset condition obtained from Manitoba Hydro's transmission line patrol database was the second characteristic used and accounts for 80 percent of the condition index. Reports reviewed for each line summarize annual visual inspections and note problems such as bent/broken/cracked footings, submerged/sinking/heaving footings, tilted footings, spreads, and bent tower steel.

Transmission System Overhead Conductors

Health Index Formulation

Due to the nature of overhead conductors, the methodology differs from that used by the third party consultant. Age was the primary qualifier used for condition assessment of transmission conductors. Reports from Manitoba Hydro's transmission line patrol database were reviewed for each line and used to validate the condition assigned based on age. These reports summarize annual visual inspections and note problems such as broken strands, bird caging, nicks/scars, and burn marks. For several lines the condition was adjusted to more accurately reflect the maintenance patrol reports.

HVDC System Synchronous Condenser:

The criteria used in evaluating the condition of the synchronous condenser are as follows:

- Age of the asset
- Maintenance history -repairs, leaking, increased tolerances, or additional maintenance impact the score. Discussion with the project manager to determine what additional work was carried out between overhauls.
- Operation performance - review of outages to see if there have been additional outages, or vibration issues.
- Physical Condition- Visual of the exterior for signs of deterioration, review of notes on internal inspection, plus assessments from engineering make up this score.

The synchronous condensers have a useful life expectancy of 65 years. The refurbishment programs, every 15 years, address the major issues found through maintenance, failures and obsolescence. The refurbishment of the unit substantially affects the life expectancy of these units.

HVDC System Converter Transformer:

The criteria used in evaluating the condition of the converter transformer are as follows:

- Oil Samples - review of dielectric strength, moisture and combustible gas generation.
- Power Factor - review of capacitance bridge tests and excitation current
- Winding DC Resistance - considers the test results from resistance tests, turn to turn ratio test and SFRA tests
- Operation and maintenance - review of outages, maintenance history, and a corresponding reduction in score for failures.
- Internal inspections of units looking for core shifting, missing blocks. External inspections looking for weld cracks, leaks, and cracked porcelain. The engineer's internal inspection is more heavily weighted than the exterior inspection.
- Age of the unit

The converter transformer has a useful life of 40-50 years.

HVDC System Valve Group

The criteria used in evaluating the condition of the valve group are as follows:

- Age of unit
- Maintenance history - repairs, unavailability of parts or additional maintenance would reduce the score
- Operational performance - review of outages to see if there have been additional outages, and a corresponding reduction in score for failures
- Physical Condition - visual of the exterior for signs of deterioration, broken fasteners, leaks in piping, loss of support for cooling pipes, and optical fibres.

The valve group has a useful life of 25 years.

Valve groups in Bipole 2 are all of the same generation and are all showing similar wear characteristics. Bipole 1 has two different valve group types in Pole 1 and Pole 2 and are showing different issues. Within Pole 1 there are differences in the issues found, which makes direct comparisons of the valve groups difficult. This therefore requires individual assessments of the valve groups to determine their respective conditions.

The failure of a valve group is a gradual process as various components wear out, or fail and require custom made solutions to restore to service. Manufacturers only continue supporting a valve group design for a limited time. Eventually there are too many items to have custom designed, and built causing the replacement of the valve group.

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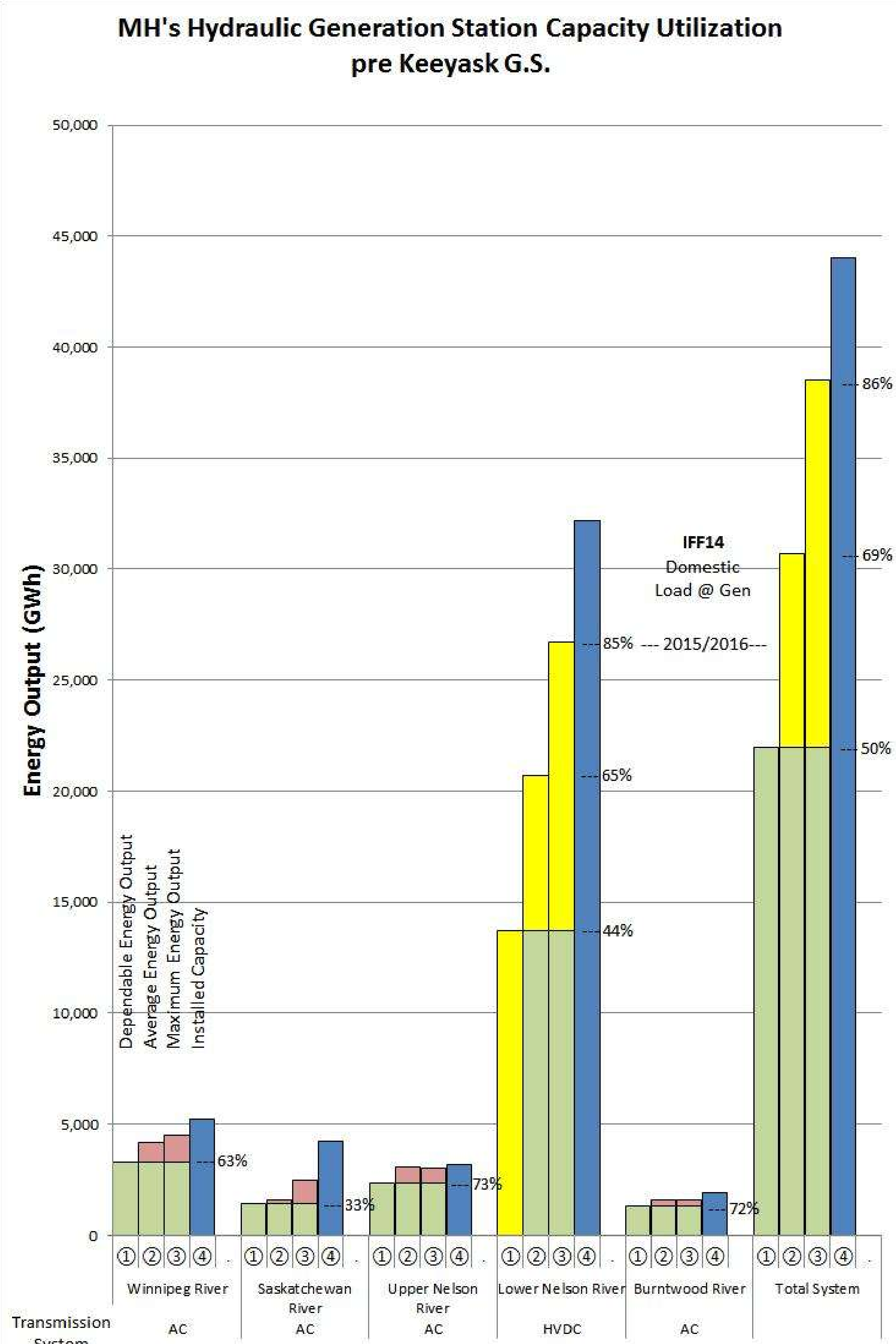
MH's Hydraulic Generation Station Capacity Utilization
pre Keeyask G.S.
Energy Output (GWh)
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Dependable Energy Output
Average Energy Output
Maximum Energy Output
Installed Capacity
63%
33%
73%
85%
65%
44%
72%
86%
69%
50%
IFF14
Domestic
Load @ Gen
--- 2015/2016---
① ② ③ ④
Winnipeg River
Saskatchewan River
Upper Nelson River
Lower Nelson River
Burntwood River
Total System
Transmission System
AC
AC
AC
HVDC
AC

Figure B-2

AVERAGE UNIT REVENUE/COST CALCULATION IFF14

VOLUMES (in GW.h)	FORECAST -> 2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Demand:																				
Manitoba Domestic Energy Sales	22214	22458	22458	22881	23009	23250	23318	23458	23664	23868	24099	24336	24572	24807	25041	25325	25617	25917	26226	26546
Domestic energy Losses	3108	3297	3264	3302	2987	3013	2982	2919	2947	2976	3007	3040	3072	3107	3140	3178	3219	3260	3302	3345
Firm & Opportunity Export Sales to Canada	851	481	860	833	856	870	753	744	602	583	565	489	471	513	502	491	519	513	495	485
Firm & Opportunity Export Sales to US	9184	8596	6444	6192	6143	6289	9464	10232	10207	10017	9789	9462	9410	8960	8780	8559	8200	7870	7501	7258
Net Transmission Losses	958	933	665	632	630	648	927	991	970	949	919	884	877	840	819	793	764	727	692	664
Total Demand Volumes:	**36315**	**35764**	**33691**	**33841**	**33624**	**34071**	**37444**	**38345**	**38389**	**38394**	**38379**	**38211**	**38401**	**38227**	**38281**	**38347**	**38319**	**38287**	**38217**	**38297**
Supply:																				
MH Hydraulic Generation	35116	34418	31084	31129	30907	31456	34535	35275	35251	35253	35138	35078	35243	35141	35144	35146	35224	35125	35133	35157
MH Thermal Generation	101	121	326	349	350	298	151	142	147	140	148	148	155	122	118	120	108	107	106	108
Purchased Energy	1098	1226	2281	2363	2367	2316	2758	2927	2991	3000	3094	2984	3004	2964	3019	3082	2987	3056	2979	3031
Total Supply Volumes:	**36315**	**35764**	**33691**	**33841**	**33624**	**34071**	**37444**	**38345**	**38389**	**38393**	**38379**	**38211**	**38401**	**38227**	**38281**	**38347**	**38319**	**38287**	**38217**	**38297**

REVENUE/COST (in milions of dollars)	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Total Manitoba Domestic Energy Sales:																				
Manitoba Domestic Energy Sales @ Approved Rates	1 436.742	1 454.388	1 460.247	1 482.604	1 490.283	1 501.465	1 505.896	1 513.421	1 525.486	1 537.543	1 551.384	1 565.461	1 579.532	1 593.283	1 607.122	1 623.939	1 641.157	1 658.777	1 677.031	1 695.791
Additional Domestic Revenue	0.000	57.448	117.638	182.720	249.787	320.910	394.053	471.445	554.231	641.409	734.027	831.780	934.799	1 043.117	1 157.220	1 279.663	1 409.139	1 485.929	1 565.867	1 648.967
Manitoba Domestic Sales	**1 436.742**	**1 511.836**	**1 577.885**	**1 665.324**	**1 740.070**	**1 822.375**	**1 899.949**	**1 984.866**	**2 079.717**	**2 178.952**	**2 285.411**	**2 397.241**	**2 514.331**	**2 636.400**	**2 764.342**	**2 903.602**	**3 050.296**	**3 144.706**	**3 242.898**	**3 344.758**
Extraprovincial Revenue:																				
Total Export Sales to Canada	28.748	16.104	43.626	43.531	47.304	51.022	46.615	48.502	36.226	37.180	37.246	32.888	32.290	37.764	37.507	37.947	41.842	42.826	42.202	42.644
Total Export Sales to USA	343.003	380.033	379.506	386.312	403.741	435.497	741.684	866.129	892.952	920.218	928.219	864.490	879.933	851.215	849.642	855.646	835.028	823.503	805.418	804.815
Other Non-Energy Related Revenues	19.698	15.880	2.765	2.820	2.876	2.934	2.990	3.046	3.104	3.163	3.223	3.285	3.347	3.411	3.475	3.542	3.609	3.677	3.747	3.818
Transmission Credits	17.443	22.140	23.841	24.294	24.755	24.824	25.296	25.776	26.266	26.765	27.274	27.792	28.320	28.858	29.406	29.965	30.534	31.114	31.706	32.308
Extraprovincial Revenue	**408.892**	**434.157**	**449.738**	**456.958**	**478.677**	**514.277**	**816.584**	**943.454**	**958.548**	**987.327**	**995.962**	**928.454**	**943.890**	**921.247**	**920.031**	**927.099**	**911.013**	**901.120**	**883.073**	**883.586**
Water Rentals & Assessments:																				
MH Water Rentals	117.417	115.049	103.902	104.051	103.310	105.144	115.437	117.912	117.830	117.838	117.451	117.252	117.802	117.462	117.474	117.479	117.738	117.408	117.434	117.516
Assessments	4.934	5.683	6.165	6.329	6.499	6.567	6.742	6.923	7.108	7.300	7.496	7.696	7.903	8.115	8.334	8.558	8.789	9.026	9.269	9.521
Other Costs	2.118	2.115	2.100	2.118	2.137	2.154	2.172	2.190	6.870	7.330	7.595	7.458	7.654	7.858	8.033	8.362	8.715	8.991	9.368	9.765
Water Rentals & Assessments:	**124.469**	**122.847**	**112.167**	**112.499**	**111.946**	**113.866**	**124.351**	**127.024**	**131.808**	**132.467**	**132.541**	**132.407**	**133.359**	**133.435**	**133.841**	**134.399**	**135.243**	**135.425**	**136.071**	**136.802**
Fuel & Power Purchased:																				
MH Thermal Generation	6.179	6.582	19.875	22.437	23.634	21.194	12.914	12.716	13.672	13.493	14.642	15.258	16.653	13.745	13.878	14.658	13.923	14.300	14.763	15.729
Purchased Energy	70.910	73.771	114.268	120.552	123.099	123.490	140.962	153.485	159.405	168.054	176.726	171.822	177.022	179.097	185.295	194.239	194.241	202.792	204.118	214.221
Other Non-Energy related Costs	14.142	12.663	8.777	9.148	9.453	9.568	12.076	29.249	16.313	16.730	17.215	17.686	18.198	18.556	19.048	19.579	20.064	20.610	21.174	21.773
Transmission Charges	42.958	37.416	48.013	50.034	50.985	51.131	67.564	67.344	67.969	68.612	69.275	70.213	70.914	71.636	72.378	73.141	78.423	79.229	80.057	80.908
Fuel & Power Purchased	**134.189**	**130.432**	**190.933**	**202.172**	**207.171**	**205.383**	**233.516**	**262.795**	**257.359**	**266.890**	**277.858**	**274.979**	**282.786**	**283.033**	**290.599**	**301.616**	**306.651**	**316.932**	**320.113**	**332.631**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
Manitoba Domestic Energy Sales @ Approved Rates	$ 64.68	$ 64.76	$ 65.02	$ 64.80	$ 64.77	$ 64.58	$ 64.58	$ 64.52	$ 64.47	$ 64.42	$ 64.38	$ 64.33	$ 64.28	$ 64.23	$ 64.18	$ 64.12	$ 64.07	$ 64.00	$ 63.94	$ 63.88
Additional Domestic Revenue	-	2.56	5.24	7.99	10.86	13.80	16.90	20.10	23.42	26.87	30.46	34.18	38.04	42.05	46.21	50.53	55.01	57.33	59.71	62.12
Total Manitoba Domestic Energy Sales @ meter	64.68	67.32	70.26	72.78	75.62	78.38	81.48	84.61	87.89	91.29	94.83	98.51	102.32	106.28	110.39	114.65	119.07	121.34	123.65	126.00
Total Export Sales to Canada	35.86	41.32	56.73	58.67	61.85	65.44	70.39	74.22	70.89	75.53	78.53	82.67	85.02	89.47	91.24	94.72	97.80	101.37	104.39	108.31
Total Export Sales to USA (includes Net Trans Credits)	34.57	42.44	55.14	58.23	61.46	65.06	73.90	80.58	83.40	87.68	90.53	86.88	88.98	90.23	91.87	94.92	96.00	98.52	100.92	104.20
Total Export Sales	34.67	42.39	55.31	58.28	61.50	65.11	73.67	80.20	82.80	87.12	89.98	86.71	88.83	90.19	91.84	94.91	96.09	98.66	101.10	104.41
MH Hydraulic Generation (Water Rentals)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	61.39	54.56	61.03	64.31	67.54	71.04	85.53	89.55	92.72	96.07	99.18	103.09	107.44	112.66	117.70	122.43	129.03	134.10	139.75	145.03
Purchased Energy (Including Assessments)	69.06	64.81	52.79	53.70	54.76	56.15	53.55	54.80	55.67	58.46	59.54	60.15	61.57	63.15	64.14	65.81	67.96	69.31	71.64	73.81

AVERAGE UNIT REVENUE/COST CALCULATION IFF13

VOLUMES (in GW.h)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Demand:																				
Manitoba Domestic Energy Sales	21994	22305	22557	22783	22988	23292	23603	23912	24236	24560	24893	25235	25576	25910	26243	26616	26986	27351	27709	28067
Domestic energy Losses	3198	3237	3122	3140	2831	2874	2901	2900	2929	2994	3045	3115	3184	3222	3342	3381	3448	3489	3544	3595
Firm & Opportunity Export Sales to Canada	690	765	580	586	597	588	583	448	449	444	448	427	435	402	587	780	761	779	771	760
Firm & Opportunity Export Sales to US	9998	8921	6583	6437	6600	6192	6315	9210	9831	9663	9286	8855	8374	9807	12273	12947	12555	12266	12044	11720
Net Transmission Losses	925	913	648	628	640	593	606	868	920	901	861	807	761	926	1206	1277	1233	1210	1183	1147
Total Demand Volumes:	**36806**	**36140**	**33490**	**33574**	**33656**	**33538**	**34007**	**37338**	**38365**	**38561**	**38532**	**38439**	**38330**	**40267**	**43652**	**45001**	**44983**	**45096**	**45251**	**45289**
Supply:																				
MH Hydraulic Generation	35143	34321	30910	30875	30854	30612	31146	34298	35124	35265	35208	34905	34852	37263	40974	42011	41934	42142	42213	42210
MH Thermal Generation	114	132	348	350	357	372	333	230	233	238	229	256	228	249	223	229	229	210	213	210
Purchased Energy	1548	1687	2232	2348	2444	2555	2529	2810	3008	3059	3095	3278	3250	2755	2456	2761	2820	2744	2825	2869
Total Supply Volumes:	**36805**	**36140**	**33490**	**33574**	**33656**	**33538**	**34007**	**37338**	**38365**	**38561**	**38532**	**38439**	**38330**	**40267**	**43652**	**45001**	**44983**	**45096**	**45251**	**45289**

REVENUE/COST (in milions of dollars)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Total Manitoba Domestic Energy Sales:																				
Manitoba Domestic Energy Sales @ Approved Rates	1 396.088	1 407.672	1 423.207	1 438.093	1 452.299	1 470.697	1 489.539	1 508.397	1 527.644	1 547.533	1 567.628	1 588.388	1 609.069	1 629.119	1 649.283	1 671.588	1 693.740	1 715.486	1 736.903	1 758.320
Additional Domestic Revenue	0.000	55.603	114.654	177.234	243.420	314.334	389.773	469.880	555.015	645.577	741.712	843.962	952.279	1 066.579	1 187.578	1 317.211	1 454.288	1 598.904	1 751.418	1 912.502
Manitoba Domestic Sales	**1 396.088**	**1 463.275**	**1 537.861**	**1 615.327**	**1 695.719**	**1 785.031**	**1 879.312**	**1 978.277**	**2 082.659**	**2 193.110**	**2 309.340**	**2 432.350**	**2 561.348**	**2 695.698**	**2 836.861**	**2 988.799**	**3 148.028**	**3 314.390**	**3 488.321**	**3 670.822**
Extraprovincial Revenue:																				
Total Export Sales to Canada	24.182	23.524	19.281	22.107	25.464	27.799	29.371	22.785	24.158	24.914	26.918	26.325	28.023	25.746	40.709	57.274	58.127	62.156	63.938	65.628
Total Export Sales to USA	350.452	329.129	320.587	345.425	392.816	396.894	430.767	712.902	812.871	829.979	828.623	814.539	740.286	923.100	1 168.842	1 258.488	1 254.391	1 249.818	1 264.261	1 263.869
Other Non-Energy Related Revenues	15.587	11.423	2.416	2.461	2.550	2.599	2.648	2.698	2.750	2.802	2.855	2.909	2.965	3.021	3.078	3.137	3.196	3.257	3.319	3.382
Transmission Credits	18.206	18.834	19.290	19.754	20.568	21.000	21.399	21.805	22.220	22.642	23.072	23.510	23.957	24.412	24.876	25.349	25.830	26.321	26.821	27.331
Extraprovincial Revenue	**408.426**	**382.910**	**361.574**	**389.747**	**441.398**	**448.292**	**484.185**	**760.191**	**861.999**	**880.336**	**881.468**	**867.284**	**795.231**	**976.280**	**1 237.506**	**1 344.248**	**1 341.544**	**1 341.552**	**1 358.339**	**1 360.210**
Water Rentals & Assessments:																				
MH Water Rentals	117.480	114.725	103.321	103.204	103.132	102.323	104.108	114.646	117.407	117.875	117.687	116.672	116.496	124.556	136.958	140.427	140.168	140.862	141.100	141.092
Assessments	5.207	5.543	5.721	5.900	6.188	6.365	6.535	6.708	6.886	7.069	7.258	7.451	7.649	7.853	8.063	8.278	8.499	8.727	8.960	9.200
Other Costs	2.213	2.266	2.239	2.258	2.277	2.297	2.317	2.338	2.359	2.380	2.402	2.425	2.447	2.470	2.494	2.518	2.543	2.568	2.593	2.619
Water Rentals & Assessments:	**124.900**	**122.534**	**111.281**	**111.362**	**111.598**	**110.985**	**112.960**	**123.691**	**126.652**	**127.325**	**127.347**	**126.548**	**126.592**	**134.880**	**147.515**	**151.224**	**151.210**	**152.157**	**152.653**	**152.911**
Fuel & Power Purchased:																				
MH Thermal Generation	6.495	8.221	21.990	23.134	25.270	27.652	26.887	21.095	22.250	23.527	23.565	27.130	25.545	28.939	27.230	29.230	30.467	29.450	31.036	31.789
Purchased Energy	81.197	82.788	103.001	110.745	119.348	126.894	129.239	140.533	154.137	161.424	171.888	184.913	183.786	165.823	154.233	172.355	180.289	179.185	189.121	197.346
Other Non-Energy related Costs	11.353	8.768	6.804	7.045	7.304	7.560	7.822	8.951	9.402	9.690	9.987	10.294	10.610	10.937	11.273	11.620	11.978	12.347	12.728	13.121
Transmission Charges	45.311	42.530	41.717	47.648	50.630	51.692	52.674	79.572	78.916	78.419	78.065	77.843	77.741	77.726	77.768	77.866	78.020	78.230	78.495	78.814
Fuel & Power Purchased	**144.355**	**142.306**	**173.511**	**188.572**	**202.552**	**213.798**	**216.622**	**250.151**	**264.704**	**273.060**	**283.506**	**300.180**	**297.682**	**283.425**	**270.504**	**291.071**	**300.754**	**299.212**	**311.379**	**321.069**

AVERAGE UNIT REVENUE/COST ($/MW.h))	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33
Manitoba Domestic Energy Sales @ Approved Rates	$ 63.48	$ 63.11	$ 63.09	$ 63.12	$ 63.18	$ 63.14	$ 63.11	$ 63.08	$ 63.03	$ 63.01	$ 62.98	$ 62.94	$ 62.91	$ 62.88	$ 62.85	$ 62.80	$ 62.76	$ 62.72	$ 62.68	$ 62.65
Additional Domestic Revenue	-	2.49	5.08	7.78	10.59	13.50	16.51	19.65	22.90	26.29	29.80	33.44	37.23	41.16	45.25	49.49	53.89	58.46	63.21	68.14
Total Manitoba Domestic Energy Sales @ meter	63.48	65.60	68.18	70.90	73.77	76.64	79.62	82.73	85.93	89.30	92.77	96.39	100.15	104.04	108.10	112.29	116.65	121.18	125.89	130.79
Total Export Sales to Canada	35.87	34.97	39.38	44.63	50.28	55.95	59.63	63.79	67.41	70.47	75.44	78.24	81.51	82.83	82.00	83.12	86.75	90.38	94.03	98.08
Total Export Sales to USA (includes Net Trans Credits)	32.34	34.24	45.29	49.33	54.97	59.14	63.26	71.13	76.92	80.12	83.31	85.85	81.98	88.69	90.92	93.15	95.76	97.66	100.68	103.45
Total Export Sales	32.56	34.29	44.88	49.00	54.63	58.91	63.00	70.86	76.59	79.78	83.02	85.58	81.97	88.51	90.58	92.64	95.30	97.27	100.32	103.16
MH Hydraulic Generation (Water Rentals)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	56.84	62.18	63.19	66.13	70.71	74.37	80.85	91.64	95.49	99.00	102.86	105.98	112.22	116.31	122.26	127.54	132.83	139.93	145.46	151.44
Purchased Energy (Including Assessments)	55.83	52.36	48.71	49.67	51.35	52.16	53.69	52.40	53.53	55.08	57.88	58.68	58.90	63.03	66.09	65.43	66.95	68.49	70.11	72.00

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Manitoba Hydro

REPORT TO THE PUBLIC UTILITIES BOARD

CURTAILABLE RATE PROGRAM

APRIL 1, 2013 – MARCH 31, 2014

September 2014

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REPORT TO PUBLIC UTILITIES BOARD
CURTAILABLE RATE PROGRAM
APRIL 1, 2013 – MARCH 31, 2014

SUMMARY

This Curtailable Rate Program ("CRP") annual report covers the period from April 1, 2013 to March 31, 2014. During this period three customers participated in the program and 14 Option R curtailments were successfully initiated.

The Public Utilities Board ("PUB") Order 42/13 dated April 26, 2013 approved, on an interim basis, the CRP Reference Discount of $3.28/kW for fiscal 2013/14. Customers received monthly credits on their electrical bill for their participation in the program totaling $5,965,689 during this time.

Manitoba Hydro's 2012/13 & 2013/14 General Rate Application ("GRA") included proposed revisions to the Terms and Conditions of the Curtailable Rate Program. The main revisions included a reduction in the amount of Option A and Option R load available to customers, the elimination of curtailment Options C and CE; and a change to the hours defined as Peak and Off-Peak to correspond to a potential time-of-use rate offering.

In Order 43/13, the PUB accepted, on an interim basis, Manitoba Hydro's proposed changes to the Terms and Conditions of the CRP. As two of the changes proposed by Manitoba Hydro could not be easily reversed if final approval of the rate setting process was not granted given the proposed changes to the Terms and Conditions, Manitoba Hydro requested to defer implementation of the change in the defined hours for Peak and Off-Peak periods, and the elimination of Curtailment Options C and CE until such time as the PUB grants final approval. Manitoba Hydro also advised that it would implement the other changes to the CRP accepted by Order 43/13, including reducing the global subscription cap on Option A, but only to the extent that Option C load can still be accommodated. By letter dated June 25, 2013, the PUB accepted Manitoba Hydro's proposal.

BACKGROUND

The CRP Terms and Conditions applicable during the reporting period from April 1, 2013 to March 31, 2014 took effect on April 1, 2013.

The Terms and Conditions allow Manitoba Hydro to reserve the right to limit the amount of total curtailable load used for maintaining operating and contingency reserves[1]. Manitoba Hydro's application to revise the CRP Terms and Conditions included a reduction to available Option A and C load from 230 MW to 178 MW and available Option R load from 100 MW to 50 MW. There is no limit for Option E load. The revised caps do not affect current CRP customers. Upon final approval of the changes to the Terms and Conditions, the Option C customer will have one year to decide if they wish to convert their load to Option A or to firm service. The caps have been beneficial to both Manitoba Hydro and curtailable customers by ensuring the value of curtailable load does not depreciate. A decreased value would result in lower discounts paid to customers making the program less attractive to them.

Manitoba Hydro uses curtailable load, among other measures, to maintain operating and contingency reserves as a means of minimizing disruption to firm customers in the event of loss of generation or transmission.

Curtailable load provides value to Manitoba Hydro all year round, as curtailments for system emergencies can occur at any time of the year. However, it has the greatest value during peak times as it is during the peak periods that Manitoba Hydro's capacity surplus is the most vulnerable. Options A and C curtailable load in these hours increases the amount of capacity for sale in the export markets while Option R load can allow Manitoba Hydro to meet its contingency reserve obligations at a lower cost.

Curtailable load provides risk mitigation benefits to the power system. Curtailable load can be used to avoid shedding firm load and/or breach of North American Electric Reliability Council (NERC) standard(s) by Manitoba Hydro or the Midwest Independent System Operator-Manitoba Hydro Contingency Reserve Sharing Group (MISO-MBHydro CRSG)[2]. Option R curtailable load allows Manitoba Hydro to meet reserve obligations thereby freeing

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[1] Per North American Electric Reliability Council (NERC) Glossary of Terms, Operating Reserves: The reserves needed to protect Manitoba Hydro and its obligations to the Midwest Independent System Operator power system against Contingencies or Disturbances. These events are typically a result of loss of supply caused by sudden generating or transmission outages. Operating Reserves consist of various types including Contingency Reserves. Contingency Reserves: a component of Operating Reserves which are sufficient in magnitude and response to meet NERC Disturbance Control Standards. Contingency Reserves are comprised of Operating Reserves-Spinning and Operating Reserves-Supplemental. Curtailable load (also referred to as Interruptible Load) can be a source of Operating Reserves-Supplemental.

[2] The MISO-MBHydro CRSG is a NERC registered Contingency Reserve Sharing Group that has operated since January 1, 2010. The CRSG was established under the terms of the Amended MISO-Manitoba Hydro Coordination Agreement and executed on October 9, 2009.

up hydro generation for market transactions in the short-term opportunity energy market[3]. In this circumstance the benefits of having Option R available are dependent on Manitoba Hydro's water supply conditions as follows:

- High Water Supply - the generating capacity freed up for commercial use allows for increased hydraulic generation for export as idle generating units can be run to capture additional sales. Without Option R capacity in place energy would be spilled. With Option R load, the additional energy generated can be sold at on-peak prices.

- Average Water Supply - allows for additional hydraulic generation during on-peak hours that would otherwise be produced during off-peak hours (due to limited on-peak generating capability). In this case Manitoba Hydro captures the benefit of the price differential between on and off-peak periods.

- Low Water Supply - does not provide any significant benefits because Manitoba Hydro has sufficient shut down generating units that could be run temporarily for operating reserves purposes without relying on Option R load reductions.

Manitoba Hydro will not initiate load curtailments in order to facilitate an opportunity spot market sale[4].

PERFORMANCE FOR 2013/14

Curtailment Options:

The Curtailable Rate Program consists of four base curtailment options and three combinations. Options vary dependent on: minimum notice to curtail, maximum duration per curtailment, maximum daily hours of curtailment, maximum number of curtailments per year, and maximum annual hours of curtailment.

[3] Opportunity export sales are sales of capacity and/or energy that are not backed by dependable energy and are incremental exports that arise from time to time as a result of water conditions that are better than the lowest historic levels.

[4] Spot market sales are sales that occur on a day ahead or real time basis. They are not considered to be a capacity sale.

The three customers that participated in the Curtailable Rate Program during the April 1, 2013 to March 31, 2014 period designated a total of 228 MW to Manitoba Hydro's reserves, allocated as 80 MW Option AE, 67 MW Option A, 31 MW Option C and 50 MW Option R. The amount each customer designated as curtailable load in relation to their total load varies, and therefore, impacts their curtailable credit, as shown on the following table:

Summary of Curtailment Credit Data April 1, 2013 to March 31, 2014					
Customer	**Option(s)**	**CRP Load as % of Total Load**	**Average On-Peak MW**	**Average On-Peak LF**	**Average Monthly Cr.**
1	A, R, E	87%	194.0	94.3%	$447,671
2	A	94%	24.5	93.6%	$49,469
3	C	0%	7.1	60.2%	$0

Customer 1: 87% of total load represents 41% Option AE, 26% Option R and 20% Option A for 2013/14.

Customer 3: this customer was operating below their protected firm load and therefore had no load available for curtailment.

Load designated under Option R must be nominated as a Guaranteed Curtailment. That is, the customer must agree to shed a specified number of MW in order to be compliant with the curtailment request. Under all the other curtailment options, customers can nominate curtailable load as Guaranteed Curtailment or Curtail to Protected Firm Load.

Dependent on the curtailment option selected, Manitoba Hydro will curtail customers to meet reliability obligations only. Options A, C and R curtailments assist in securing operating and contingency reserves whereas Option E curtailments are initiated to meet firm energy requirements in the event that Manitoba Hydro expects to be short of firm energy supplies.

Implementation and Size of Curtailments:

There were 14 Option R curtailments during the April 1, 2013 to March 31, 2014 period, all of which were initiated in response to a contingency or disturbance event requiring deployment of Manitoba Hydro's supplemental reserves. The following table summarizes the duration and load in MW of each curtailment.

April 2013 to March 2014	Option 'R'	
	Hrs	MW
April 18, 2013	0.63	50
April 19, 2013	0.25	50
April 25, 2013	0.77	50
May 27, 2013	1.77	50
June 6, 2013	0.70	50
June 21, 2013	1.37	50
July 3, 2013	0.93	50
July 3, 2013	1.55	50
July 7, 2013	1.43	50
July 17, 2013	0.73	50
August 19, 2013	1.72	50
September 3, 2013	0.23	50
February 5, 2014	3.05	50
March 27, 2014	0.75	50
Total	**15.88**	**N/A**
Average	**1.13**	**50**

No NOV
NO DEC
NO JAN

All curtailments occurred during peak hours. The customer did not use an alternative power source to supply their load during the curtailments.

Manitoba Hydro continues to use telephone to communicate curtailment requirements to customers on the program. This procedure is manageable and provides the additional security that curtailment(s) will be initiated by confirmation from an agent of the customer. Manitoba Hydro experienced no difficulties in communicating the 14 curtailments during this reporting period.

Reference and Reserve Discounts:

The maximum discount available to a participating customer is called the "Reference Discount." The Reference Discount is related to the marginal value of capacity, and is adjusted on April 1 of each year by the inflation factor. The Reference Discount in effect for the reporting period April 1, 2013 to March 31, 2014 was \$3.28 per kW/month, as approved by the PUB, on an interim basis, in Order 42/13 dated April 26, 2013. Option AE customers receive 100% of the discount, while Option A and R customers receive 70% of the discount or \$2.30 per kW/month. Option C customers receive 40% of the discount or \$1.31 per kW/month.

For curtailable load nominated as 'Protect to Firm Load' the Reference Discount is calculated and credited to customers' bill each month as (A - B) x C x D where:

A = On-Peak Period Demand (kW)
B = Protected Firm Load (kW)
C = On-Peak Period Load Factor
D = Discount Amount

For curtailable load designated as a 'Guaranteed Curtailment' the Reference Discount is calculated and credited to customers' bill each month as GC x D where,

GC = the customer's guaranteed curtailable load
D = Discount Amount

Customers selecting Curtailment Option R receive, in addition to the Reference Discount, a Reserve Discount for each curtailment initiated and successfully completed. The Reserve Discount represents the value of carrying contingency reserves and is calculated and credited to customers' bill for each successful curtailment as LR x Du x FD where,

LR = amount of load reduction (in kW) requested by Manitoba Hydro's System Control to the customer at the time of an Option R curtailment
Du = duration of the curtailment (in hours)
FD[5] = fixed discount amount, currently set at $0.04 per kWh

The table below illustrates the amount of the monthly Reference Discount Credit that each customer received from April 1, 2013 to March 31, 2014, as well as their monthly On-Peak Demand and On-Peak Load Factor.

Monthly Reference Discount Credit									
2013 to 2014	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Apr	208.8	92.6%	$439,020	24.6	97.6%	$51,875	31.7	59.4%	$0
May	207.8	83.9%	$408,342	24.9	93.7%	$50,388	28.6	39.5%	$0
June	175.5	93.8%	$443,042	24.6	92.5%	$49,159	19.0	6.1%	$0
Jul	175.5	97.7%	$456,860	24.6	94.7%	$50,350	0.7	70.1%	$0

[5] The Fixed Discount amount is based on the value of carrying contingency reserves on Manitoba Hydro units.

Monthly Reference Discount Credit									
2013 to 2014	Customer 1 Options AE, R, A			Customer 2 Option A			Customer 3 Option C		
	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $	On Peak MW	LF %	Discount Paid $
Aug	175.5	97.4%	$455,635	24.8	98.1%	$52,438	0.7	69.9%	$0
Sep	175.5	95.7%	$449,584	24.7	67.8%	$36,131	0.7	74.4%	$0
Oct	175.5	95.7%	$449,654	24.3	95.8%	$50,310	0.8	56.5%	$0
Nov	209.3	93.9%	$443,462	24.1	99.5%	$51,754	0.8	68.1%	$0
Dec	205.9	92.8%	$439,684	24.4	97.7%	$51,475	0.9	76.7%	$0
Jan	207.0	97.6%	$456,335	24.3	95.6%	$50,168	0.9	46.0%	$0
Feb	205.9	96.4%	$452,137	24.1	96.1%	$50,011	0.4	78.2%	$0
Mar	205.9	94.8%	$446,540	24.3	94.4%	$49,575	0.4	78.1%	$0
Total	**2,328.0**	**94.3%**	**$5,340,296**	**293.8**	**93.6%**	**$593,633**	**85.5**	**60.2%**	**$0**

The discounts shown for Customer 1 do not include the $31,760 credited in respect of the Option R Reserve Discount.

Adequacy of Terms and Conditions:

Manitoba Hydro proposed revisions to the Terms and Conditions of the Curtailable Rate Program as part of its 2012/13 & 2013/14 GRA. The revisions included:

- a reduction in the amount of Option A and Option R load available to customers;
- elimination of curtailment Options C and CE;
- change in hours defined as Peak and Off-Peak to correspond to a potential time-of-use rate offering;
- removal of the monthly variation to nominate curtailable or firm load; and
- exclusion from the program after a customer's 2nd failure to curtail in a 12 month period.

In Order 43/13, dated April 26, 2013, the PUB accepted the proposed revisions as noted above, on an interim basis. Subsequent to the receipt of that Order, Manitoba Hydro, in its letter dated May 15, 2013, informed the PUB of the difficulty in implementing a change in the defined Peak and Off-Peak hours, and elimination of Option C and CE on an interim basis, and proposed that these changes be deferred until such matters can be finalized. The PUB, in its letter dated June 25, 2013, confirmed Manitoba Hydro's proposed approach.

The Terms and Conditions have protected Manitoba Hydro's contingency reserves and provided operating reserves that satisfy the requirements of NERC and the MISO-MB Hydro CRSG.

CONCLUSION

The Curtailable Rate Program facilitates fulfilling Manitoba Hydro's commitment of carrying, deploying, and re-establishing contingency reserves to meet its obligations with the MISO-MBHydro CRSG and to maintain compliance to NERC Standards. The program also assists in minimizing disruption to Manitoba Hydro's firm customers.

CRP continues to fulfill Manitoba Hydro's obligations, and with the above mentioned changes to the Terms and Conditions, will preserve the value of the program to both Manitoba Hydro and its customers.

ESTIMATE OF THE VALUE OF CURTAILABLE LOAD TO MANITOBA HYDRO

The value of curtailable load to Manitoba Hydro is related to an estimate of the marginal cost of firm, long-term capacity. Over the long term, a representative value for capacity can be developed by estimating the annual carrying cost (includes finance and depreciation costs but not operating/fuel costs) of the lowest cost resource required to provide capacity to Manitoba Hydro, which is a simple cycle combustion turbine (SCCT). In 2005 the annual carrying cost of a SCCT was estimated to be $78 per kW per year, or $6.50 per kW per month, evaluated at load. It was proposed that this cost would escalate at the rate of inflation. This cost was reviewed in 2012 and was found to be appropriate going forward. This approach has the advantage of providing a clear transparent value, which is also stable over time and is consistent with the approach that is utilized to evaluate the benefits of other resource options such as DSM that may have a capacity component.

Curtailable load is less valuable than a generation resource such as a SCCT. The SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during extended emergency situations. Once in place, a SCCT can be relied upon as a permanent, long-term resource, unlike curtailable load which can be terminated with a notice period of one year. Curtailable load normally has more value in the summer months, when it can assist in supporting seasonal capacity exports, and in the peak winter months, when it may add reliability to the Manitoba Hydro system. Curtailable load will provide more winter reliability benefits in years in which there is little capacity surplus on the system. When there is a significant capacity surplus on the Manitoba Hydro system, curtailable load provides less winter value than it would, for example, in the period around the 2023/24 time period, when the requirement to add generation to serve domestic customers may be expected to occur with 2013 planning assumptions and base demand side management program assumptions. The value of reliability benefits in a single year is not easily determined, which is why longer-term levelized values are used to infer the benefits of curtailable load.

The economic benefits of curtailable load can vary considerably year to year for a number of reasons. In the case of Option R CRP, the economic benefits derived from this option will vary depending on water conditions. Export market conditions can also impact the value of curtailable load to Manitoba Hydro. In the MISO market, current supply and demand conditions for capacity resources can cause variability in the near term value of capacity resources. Use of a longer-term levelized value maintains stability in CRP pricing, therefore sheltering the CRP customer from these sources of variability.

As described above curtailable load is less valuable than a SCCT because it has limited dispatchability, is not sustainable in reducing load over longer periods, and is not guaranteed to exist in the long term. Therefore in order to reflect these factors, curtailable load is assigned a long-term levelized value that is 42% of the annual carrying cost of a SCCT. After consideration of inflation subsequent to the 2011 base year, this yields an estimate of benefits for the year beginning April 1, 2013 of $3.28 per kW/month, which is referred to as the "Reference Discount". This value would apply to the curtailable rate option that provides the most value to Manitoba Hydro, that being Options AE and RE, for which the discount is set to return 100% of the estimated value of curtailable load to the customer. Other options provide less flexibility and are accordingly worth less to Manitoba Hydro. These have been priced to reflect their lesser value to Manitoba Hydro but still to return the full estimated value of that option to the customer.

APPENDIX

A. DEPENDABLE SUPPLY & DEMAND

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2014/15 PRP
No New Resources

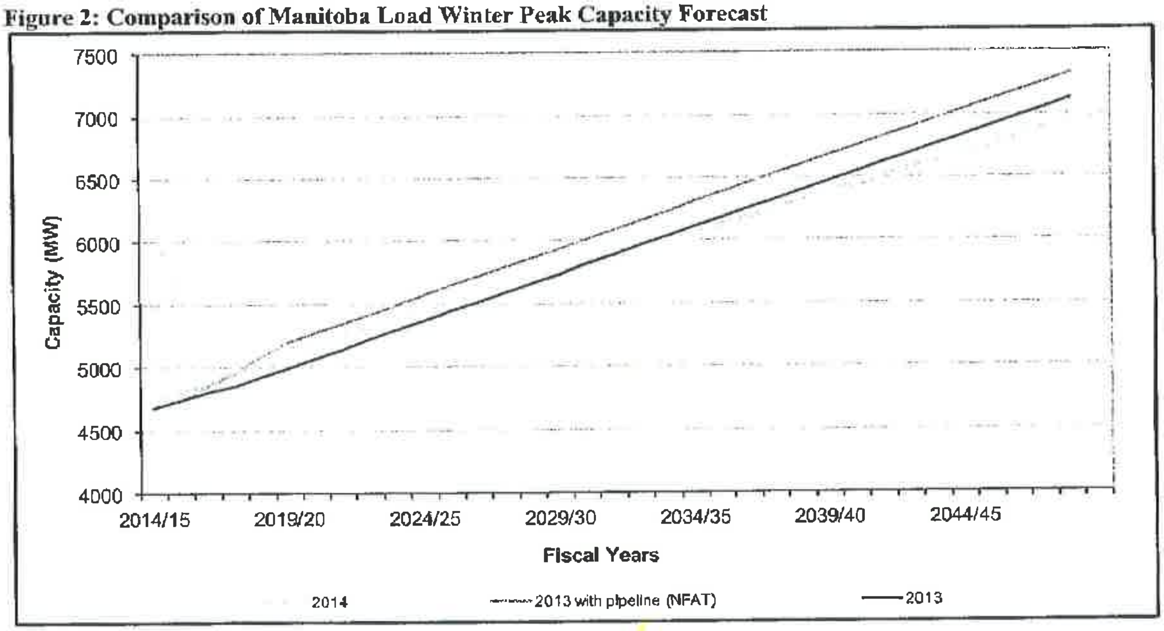
Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Power Resources																			
New Power Resources																			
New Hydro																			
Conawapa																			
Keeyask							90	630	630	630	630	630	630	630	630	630	630	630	630
1 **Total New Hydro**							90	630	630	630	630	630	630	630	630	630	630	630	630
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
New NUG PPA																			
Contracted																			
Proposed				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
3 **Total New NUG PPA**				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
4 **Total New Power Resources**	1+2+3			**12**	**12**	**12**	**102**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**	**642**
Base Supply Power Resources																			
Existing Hydro		5 133	5 172	5 164	5 190	5 195	5 196	5 181	5 172	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167
Existing Thermal																			
Brandon Coal - Unit 5		105	105	105	105	105													
Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports		605	605	605	605	605	605	605	605	605	605	605	220	220	220	220	220		
Proposed Imports																			
Pointe du Bois Rebuild																			
Bipole III Reduced Losses						90	90	80	80	80	80	80	80	80	80	80	80	80	80
5 **Total Base Supply Power Resources**		6 123	6 228	6 286	6 312	6 407	6 303	6 278	6 269	6 264	6 264	6 264	5 879	5 879	5 879	5 879	5 879	5 659	5 659
6 **Total Power Resources**	4+5	**6 123**	**6 228**	**6 298**	**6 324**	**6 419**	**6 405**	**6 920**	**6 911**	**6 906**	**6 906**	**6 906**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 301**	**6 301**
Peak Demand																			
2014 Base Load Forecast		4 716	4 803	4 861	4 985	5 068	5 166	5 223	5 284	5 342	5 400	5 458	5 516	5 574	5 632	5 690	5 748	5 808	5 869
Less: 2014 DSM Forecast		- 60	- 111	- 169	- 226	- 293	- 353	- 406	- 449	- 475	- 498	- 517	- 533	- 550	- 566	- 582	- 585	- 589	- 592
7 **Manitoba Net Load**		4 656	4 692	4 692	4 759	4 775	4 813	4 817	4 835	4 867	4 902	4 941	4 983	5 024	5 066	5 108	5 163	5 219	5 277
Contracted Exports		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	275	275	275
Proposed Exports																			
8 **Total Exports**		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	275	275	275
9 **Total Peak Demand**	7+8	**5 382**	**5 176**	**5 416**	**5 483**	**5 334**	**5 372**	**5 596**	**5 743**	**5 747**	**5 782**	**5 821**	**5 368**	**5 409**	**5 341**	**5 383**	**5 438**	**5 494**	**5 552**
10 Reserves		513	563	563	571	573	577	578	580	584	588	593	598	603	608	613	620	626	633
11 **System Surplus**	6-9-10	**228**	**489**	**319**	**270**	**512**	**456**	**746**	**588**	**575**	**536**	**492**	**555**	**509**	**572**	**525**	**463**	**181**	**116**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2014/15 PRP
No New Resources

	Fiscal Year		2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Keeyask		630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630
1	**Total New Hydro**		630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630	630
	New Thermal																			
	SCGT																			
	CCGT																			
2	Total New Thermal																			
	New NUG PPA																			
	Contracted																			
	Proposed		12	12	12	12														
3	**Total New NUG PPA**		12	12	12	12														
4	**Total New Power Resources**	1+2+3	642	642	642	642	630	630	630	630	630	630	630	630	630	630	630	630	630	630
	Base Supply Power Resources																			
	Existing Hydro		5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167
	Existing Thermal																			
	Brandon Coal - Unit 5																			
	Selkirk Gas		132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Contracted Imports																			
	Proposed Imports																			
	Pointe du Bois Rebuild									87	87	87	87	87	87	87	87	87	87	87
	Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
5	**Total Base Supply Power Resources**		5 659	5 659	5 659	5 659	5 659	5 659	5 659	5 746	5 746	5 746	5 746	5 746	5 746	5 746	5 746	5 746	5 746	5 746
6	**Total Power Resources**	4+5	6 301	6 301	6 301	6 301	6 289	6 289	6 289	6 376	6 376	6 376	6 376	6 376	6 376	6 376	6 376	6 376	6 376	6 376
	Peak Demand																			
	2014 Base Load Forecast		5 931	5 995	6 058	6 122	6 185	6 249	6 313	6 376	6 440	6 504	6 567	6 631	6 694	6 758	6 822	6 885	6 949	7 012
	Less: 2014 DSM Forecast		- 594	- 596	- 598	- 601	- 604	- 607	- 610	- 613	- 614	- 614	- 615	- 615	- 615	- 615	- 615	- 615	- 615	- 615
7	**Manitoba Net Load**		5 337	5 399	5 460	5 521	5 581	5 642	5 703	5 763	5 826	5 890	5 952	6 016	6 079	6 143	6 207	6 270	6 334	6 397
	Contracted Exports		275	275	275															
	Proposed Exports																			
8	**Total Exports**		275	275	275															
9	**Total Peak Demand**	7+8	5 612	5 674	5 735	5 521	5 581	5 642	5 703	5 763	5 826	5 890	5 952	6 016	6 079	6 143	6 207	6 270	6 334	6 397
10	Reserves		640	648	655	663	670	677	684	692	699	707	714	722	729	737	745	752	760	768
11	**System Surplus**	6-9-10	49	- 21	- 89	117	38	- 30	- 98	- 79	- 149	- 221	- 290	- 362	- 432	- 504	- 576	- 646	- 718	- 789

As shown in Figure 2, the 2014 Gross Total Peak demand forecast for 2032/33 is down 28 MW compared to the 2013 Load Forecast, less than a half a year of load growth. (1 year = approximately 70 MW). The 2014 load forecast is lower than that provided during the NFAT process due to a decrease in forecasted Top Consumers in the pipeline sector and lower residential customer forecast due to increased codes and standards.

Figure 2: Comparison of Manitoba Load Winter Peak Capacity Forecast



3.2 Demand Side Management

Incremental demand side management (DSM) included in the 2014/15 Power Resource Plan is 582 MW and 2797 GW.h achieved by 2028/29. This is a significant increase from the 2013 PRP (which included 166 MW and 773 GW.h achieved by 2027/28) based on an in-depth review of the market. Incremental DSM included in the Power Resource Plan excludes savings already achieved to date, savings achieved through codes and standards which are included in the Load Forecast, and savings from curtailable rates programming that do not qualify as winter peak capacity or dependable energy.

The forecast submitted for the NFAT analysis included future code savings anticipated to arise through efforts under the commercial New Buildings Program. With the recent Manitoba adoption of the National Energy Code for Buildings, the future energy impacts from these codes have been re-allocated from the Demand Side Management forecast under the 2014 Power Resource Plan and are now reflected in the 2014 Load Forecast due to the formal code implementation in the new construction market.

Figures 3 and 4 show the changes in demand side management assumptions for energy and capacity between the 2013/14 Power Resource Plan, the 2013 NFAT Level 2 DSM, and the 2014/15 Power Resource Plan.

Figure 1: System Firm Winter Peak Demand and Capacity Resources (MW) @ generation

	Fiscal Year		2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34
	Manitoba Hydro Power Resources																					
	New Hydro																					
	Keeyask G.S.							90	630	630	630	630	630	630	630	630	630	630	630	630	630	630
	Total New Hydro							90	630	630	630	630	630	630	630	630	630	630	630	630	630	630
	New NUG Purchase				12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
1	**Total New Power Resources**				12	12	12	102	642	642	642	642	642	642	642	642	642	642	642	642	642	642
	Existing Hydro		5 133	5 172	5 164	5 190	5 195	5 196	5 181	5 172	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167	5 167
	Existing Thermal																					
	Brandon Unit 5		105	105	105	105	105															
	Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	Total Existing Thermal		385	451	517	517	517	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412
	Imports		605	605	605	605	605	605	605	605	605	605	605	220	220	220	220	220				20
	Bipole III Line Reduction						90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80
2	**Total Base Supply Power Resources**		**6 123**	**6 228**	**6 286**	**6 312**	**6 407**	**6 303**	**6 278**	**6 269**	**6 264**	**6 264**	**6 264**	**5 879**	**5 879**	**5 879**	**5 879**	**5 879**	**5 659**	**5 659**	**5 659**	**5 679**
3	**Total Power Resources**	1+2	**6 123**	**6 228**	**6 298**	**6 324**	**6 419**	**6 405**	**6 920**	**6 911**	**6 906**	**6 906**	**6 906**	**6 521**	**6 521**	**6 521**	**6 521**	**6 521**	**6 301**	**6 301**	**6 301**	**6 321**
	Peak Demand																					
	2014 Base Load Forecast		4 716	4 803	4 861	4 985	5 068	5 166	5 223	5 284	5 342	5 400	5 458	5 516	5 574	5 632	5 690	5 748	5 808	5 869	5 931	5 995
	Less: 2014 Base DSM Forecast		- 60	- 111	- 169	- 226	- 293	- 353	- 406	- 449	- 475	- 498	- 517	- 533	- 550	- 566	- 582	- 585	- 589	- 592	- 594	- 596
4	**Manitoba Net Load**		**4 656**	**4 692**	**4 692**	**4 759**	**4 775**	**4 813**	**4 817**	**4 835**	**4 867**	**4 902**	**4 941**	**4 983**	**5 024**	**5 066**	**5 108**	**5 163**	**5 219**	**5 277**	**5 337**	**5 399**
	Contracted Exports		726	484	724	724	559	559	779	908	880	880	880	385	385	275	275	275	275	275	275	275
	Proposed Exports																					
5	**Total Exports**		**726**	**484**	**724**	**724**	**559**	**559**	**779**	**908**	**880**	**880**	**880**	**385**	**385**	**275**	**275**	**275**	**275**	**275**	**275**	**275**
6	**Total Peak Demand**	4+5	**5 382**	**5 176**	**5 416**	**5 483**	**5 334**	**5 372**	**5 596**	**5 743**	**5 747**	**5 782**	**5 821**	**5 368**	**5 409**	**5 341**	**5 383**	**5 438**	**5 494**	**5 552**	**5 612**	**5 674**
7	Reserves		513	563	563	571	573	577	578	580	584	588	593	598	603	608	613	620	626	633	640	648
	System Surplus	3-6-7	**228**	**489**	**319**	**270**	**512**	**456**	**746**	**588**	**575**	**536**	**492**	**556**	**509**	**572**	**525**	**464**	**181**	**116**	**49**	**(0)**

Figure 4: Summer Peak Demand and Capacity Resources (MW) @ generation (based on MISO surplus capacity calculations)

Notes / Row	Month	Jul-2015	Jul-2016
	Supply		
1	Total Generation Capacity	5474	5474
	Capacity Imports	0	0
2	Total Supply	5474	5474
	Peak Demand		
	2014 Base Load Forecast	3341	3384
	Less: 2014 Base DSM Forecast	71	116
	Less: Curtailable Load, Station Service	166	166
	Plus: 10% Export Losses	110	132
3	Manitoba Net Load	3214	3234
4	Capacity Exports	1073	1292
5	Total Peak Demand (3 + 4)	4287	4526
6	MISO Planning Reserves	228	230
7	**Surplus (2 - 5 - 6)**	**959**	**718**

Notes:

1. MISO capacity surplus based on generation unforced capacity (i.e. net of forced outage rate). Figure includes all MH supplies however, not all MH generation is necessarily offered to capacity market (e.g., Brandon 5 generation excluded)

6. MISO planning reserve (7.1%)

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Section:	Appendix 9.1 Appendix 11.22	Page No.:	PUB/MH I-66(a) PUB/MH I-83(b)
Topic:	Power Resources		
Subtopic:	Hydraulic Generation		
Issue:	Actual 2013/14 power resources		

PREAMBLE TO IR (IF ANY):

MH's peak winter domestic load in 2013/14 was 4,743 MW when compared to 5,133 MW of hydraulic generation capacity was not quite sufficient to satisfy the Permit No. 224 export requirement of 500 MW (plus 50 MW transmission losses).

QUESTION:

a) Explain how MH dealt with the 160 MW shortfall in peak capacity.

b) Did MH utilize the existing diversity agreements to satisfy the on-peak need? If not, explain.

c) Provide the monthly cost data on the on-peak purchases ($M/GWh/¢/kWh).

d) Did MH employ the CRP resource?

RATIONALE FOR QUESTION:

MH's winter supply demand criteria appear to involve significant peak capacity imports in high demand years as well as low flow years.

RESPONSE:

a) Manitoba Hydro did not have a shortfall in capacity during the 2013/14 peak load hour, nor was it a net importer in that hour.

Table 9.1 of Tab 9 of the Application lists available thermal and import capacity resources in addition to its existing hydraulic generation. The 2013/14 winter capacity resources were similar to what was provided in Table 9.1 for 2014/15 (6,123 MW total base supply power resources); totaled together, these resources exceeded the actual 2013/14 peak domestic load plus Manitoba Hydro's coincident capacity obligations in its long term export contracts.

In anticipation of the peak load hour of 2013/14, Manitoba Hydro chose to purchase energy from MISO in the Day Ahead market rather than schedule the operation of more expensive thermal generation in Manitoba. A portion of these purchases was used to meet firm export obligations with the balance required to meet projected Manitoba load requirements. Manitoba Hydro planned to utilize the firm transmission associated with its seasonal diversity agreements to ensure delivery of the MISO market energy into Manitoba.

In the operating day, as the hour approached, it was apparent Manitoba Hydro had a net surplus so Manitoba Hydro ended up selling back 100 MW into the MISO Real Time market in the peak hour, at a profit over its Day Ahead purchase.

Accounting for all exports, imports and financial settlements, Manitoba Hydro's net transaction was 90 MW export in the peak hour. This net export position was possible through the use of Manitoba Hydro's portfolio of resources including hydraulic generation, thermal generation, wind PPAs, Day Ahead purchases and exports, Real Time exports and firm transmission assets.

b) No, Seasonal Diversity energy was not purchased over the peak hour. However, Manitoba Hydro used the firm north-bound transmission reservation associated with its diversity agreements to schedule imports from the MISO Day Ahead market.

c) For January 2014, Manitoba Hydro purchased 71 GWh at a cost of $5 million during on peak hours. The average cost was 7.9 cents/kWh.

d) No, use of curtailable load was not required during this peak load hour.