Section:	1 7	Page No.:	7 49
Topic:	Capital Spending		
Subtopic:	Comparison of IFFs		
Issue:	Changes in Level of Capital Spending		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule setting out the values for the capital spending by year for each of the categories (Sustaining Capital, DSM and New Generation & Transmission) set out in Figure 1. Please also include in the schedule a breakdown of the actual capital expenditures for 2014/15.

b) In the same schedule please provide the comparable values from IFF14 as set out in the 2015/16 & 2016/17 GRA (e.g. Tab 2, Figure 2.13).

c) For the years 2015/16 and beyond, please explain any material variance (>5%) in the annual spending forecast by category compared in response to part (b).

d) In CEF15 the forecast spending for the years 2015/16 and 2016/17 appears to include not only spending deferred from 2014/15 but also spending that in CEF14 had been planned for 2017/18 and 2018/19. Please confirm whether or not this is the case.
   i. If yes, why was capital spending originally planned in CEF14 for 2017/18 and 2018/19 advanced to the two earlier years and specifically what projects were affected?
   ii. If not, what accounts for the increase/decrease profile seen in Figure 29 over these four years?

RATIONALE FOR QUESTION:

To compare capital expenditure forecast in current application with that filed in the last GRA.

RESPONSE:

Response to part a) and b)

Please see the schedule below.

Capital Spending (in millions of dollars)	MH15			MH14			MH15 Less MH14			Percentage Variance	
	Sustaining Capital	DSM	New Generation & Transmission	Sustaining Capital	DSM	New Generation & Transmission	Sustaining Capital	DSM	New Generation & Transmission	DSM	New Generation & Transmission
2015*	559	33	1 342	571	52	1 400	(12)	(19)	(58)	-36%	-4%
2016	577	62	1 951	577	59	1 855	-	3	96	5%	5%
2017	610	58	2 688	610	77	2 387	-	(19)	302	-24%	13%
2018	547	99	2 277	547	84	2 494	-	15	(217)	18%	-9%
2019	547	95	1 366	547	94	1 437	-	1	(71)	1%	-5%
2020	548	90	805	548	78	806	-	12	(1)	15%	0%
2021	573	92	368	573	73	354	-	20	15	27%	4%
2022	555	97	228	555	61	135	-	36	93	59%	69%
2023	563	72	79	563	50	67	-	22	12	45%	19%
2024	571	67	42	571	50	60	-	18	(19)	36%	-31%
2025	621	71	38	621	48	60	-	23	(22)	49%	-37%

*Amounts listed under MH15 for Fiscal year 2015 represent actual expenditures.

c) The following explains material variance greater than 5% in each category.

Demand Side Management (DSM)

The difference between the actual and forecasted results in 2015 was primarily due to delays in the LED Roadway Lighting Program and lower costs for the Performance Optimization Program.

The change in the annual forecast cashflow in 2017 was primarily due to the Load Displacement Program being delayed by one year and lower costs for the Performance Optimization Program.

The changes in the annual forecast cashflows for 2018 through 2025 was primarily due to additional requirements for various programs including Load Displacement, Other Emerging Technologies, and LED Roadway Lighting.

New Generation and Transmission

Fiscal Year	Percentage Variance	Variance $M	Explanations Greater than 5%
2017	**13%**	**$302**	The change of $302 million is primarily due to the following: $150M Keeyask – Schedule delays in 2014/15 in the construction of the main camp and south access road resulted in a deferral of the work area site development. Cash flow advanced for higher than anticipated labour costs, as well as reflow of the contingency to align with anticipated contract risks, and advancement of the General Civil Works and Turbine and Generator schedules. $114M Bipole III Transmission Line - Changes in the sequencing of construction activities including the advancement of material purchases and construction of southern sections of the transmission line advanced. In addition, project contingency was cash flowed earlier to align with the associated contract risks and cash flows. $115M Bipole III Converter Stations – Adjustments to cash flow to align with newly awarded contracts and project contingency reflowed earlier to align with the associated contract risks and cash flows. Partially offset by: ($83M) Manitoba-Minnesota Transmission Project – Deferral to 2018 due to the refinement of estimates for licensing and environmental approvals.
2018	**-9%**	**(217)**	The change of $217 million is primarily due to the following: ($125M) Keeyask – Cash flow advanced for higher than anticipated labour costs, as well as reflow of the contingency to align with anticipated contract risks, and advancement of the General Civil Works and Turbine and Generator schedules.

			($134M) Bipole III Transmission Line - See explanation for 2017. ($135M) Bipole III Converter Stations – See explanation for 2017. Partially offset by: $55M Manitoba-Minnesota Transmission Project - See explanation for 2017.
2022	**69%**	**93**	$85M Keeyask – Interest on the KCN Construction Credit Facility was accrued and reflected in CEF15 upon final close when KCN is required to make their investment decision, rather than annually. There is no change in the interest calculation method.
2023	**19%**	**12**	$9M Gillam Redevelopment & Expansion Program (GREP) – Reflects the advancement of cashflow to address operational needs and the impacts of new generation facilities.
2024	**-31%**	**(19)**	($22M) Gillam Redevelopment & Expansion Program (GREP) - See explanation for 2023.
2025	**-37%**	**(22)**	($22M) Gillam Redevelopment & Expansion Program (GREP) - See explanation for 2023.

d) Manitoba Hydro can confirm that the forecasted capital expenditures deferred from 2014/15, as well as forecasted expenditures advanced from 2017/18 and 2018/19, are included in fiscal years 2015/16 and 2016/17. The majority of the changes in annual forecasted expenditures are primarily due to cashflow revisions for the Keeyask and Bipole III projects as discussed in part c) above.

The cashflow changes for the Keeyask and Bipole III projects are partially offset by the Target Adjustment and changes in the cashflow of other project expenditures (see schedule below).

CAPITAL EXPENDITURE FORECAST (CEF15 less CEF14)

(in millions of dollars)

	2015 Under-expenditure	2016	2017	2018	2019
Major New Generation & Transmission					
Keeyask - Generation	(72)	142	150	(125)	(92)
Bipole III - Transmission Line	(75)	87	114	(134)	11
Bipole III - Converter Stations	(19)	67	115	(135)	(15)
Target Adjustment (Cost Flow)		(165)	(21)	58	(15)
Other		(31)	(75)	134	40
MAJOR NEW GENERATION & TRANSMISSION TOTAL (Excluded DSM)		**96**	**302**	**(217)**	**(71)**

Section:	1 7 Attachment 20	**Page No.:**	7 50 2
Topic:	Capital Spending		
Subtopic:	2014/15 Forecast vs. Actuals		
Issue:	Reconciliation		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Figure 1 reports 2014/15 capital investments in electric operations as $1,934 M. A similar graphic in the 2015/16 & 2016/17 GRA (Tab 2, Figure 2.13) reported forecast 2014/15 capital spending of $2,023 M, for a difference of $89 M. However, at Tab 7, page 50 (line 11) of the current Application the text suggests that actual capital spending in 2014/15 was $234 M less than forecast. Please reconcile and clarify what the $234 M value represents.

RATIONALE FOR QUESTION:

To clarify actual 2014/15 capital spending and understand reasons for variance from previous GRA forecast.

RESPONSE:

The $234M discussed in Section 7 (page 50), was an approximation for the total under expenditure in Major New Generation and Transmission (MNGT) projects. The table below shows the actual under expenditure for MNGT projects was $238M. In addition, a cost flow reduction of $161M was forecast in CEF14 reducing the under expenditure to $77M compared to the overall MNG&T forecast. A further under expenditure of $12M on Major and Base Electric capital results in a total under-expenditure of $89M compared to the annual forecast in CEF14. The table below reconciles the Figure 1 amount of $1 934M to the 2015/16 & 2016/17 GRA (Figure 2.13) amount of $2 023M.

CAPITAL EXPENDITURE REPORT
FOR THE YEAR ENDED MARCH 31, 2015
(In Thousands of Dollars)

	Fiscal Year 2014/15			
	CEF14 ANNUAL FORECAST	12 MONTH ACTUAL	VARIANCE	%
ELECTRIC OPERATIONS				
MAJOR NEW GENERATION & TRANSMISSION				
Bipole III - Transmission Line	$203	$128	$75	63
Keeyask	776	704	72	91
Bipole III - Collector Lines	58	35	23	60
Bipole III - Converter Stations	221	202	19	91
Demand Side Management - Electric	52	33	19	64
Wuskwatim - Generation	41	31	10	76
Gillam Redevelopment & Expansion Program	20	12	8	60
Riel 230/500 kV Station	36	30	6	84
Kelsey Re-runnering	14	12	2	88
Other MNG&T	184	180	4	97
MAJOR NEW GENERATION & TRANSMISSION SUBTOTAL	1 613	1 375	238	**85**
Target Adjustment (Cost Flow)	(161)	-	(161)	-
MAJOR NEW GENERATION & TRANSMISSION TOTAL	1 452	1 375	77	**95**
MAJOR & BASE CAPITAL ELECTRIC TOTAL	571	559	12	98
ELECTRIC CAPITAL TOTAL	**$2 023**	**$1 934**	**$89**	**96**

Section:	1 7 Attachment 20	**Page No.:**	7 50 2
Topic:	Capital Spending		
Subtopic:	2014/15 Forecast vs. Actuals		
Issue:	Reconciliation		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Attachment 20, page 2 shows total capital spending in 2014/15 of $1,900.6 M ($558.9 + $1,341.7) which is different than the total as set out in Figure 2.13 ($1,934 M). Please reconcile.

RATIONALE FOR QUESTION:

To clarify actual 2014/15 capital spending and understand reasons for variance from previous GRA forecast.

RESPONSE:

Manitoba Hydro inadvertently listed Major New Generation and Transmission as $1341.7 for 2014/15 in the original Attachment 20. Please see the revised table for Attachment 20 below, reflecting $1374.7 for Major New Generation and Transmission for 2014/15.

For the year ended March 31	Actuals 2015	Forecast 2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1 Cash Flow from Operations	654.6	567.1	598.6	661.8	575.7	582.9	645.9	733.9	833.9	907.7	996.6
2 Sustaining Capital Spending	558.9	577.0	609.6	547.3	547.4	547.5	572.6	554.7	559.3	571.0	621.1
3 Excess Cash Flow after Sustaining Capital Spending (1-2)	95.7	(9.9)	(11.0)	114.4	28.3	35.3	73.3	179.2	274.6	336.7	375.6
4 Capital Coverage Ratio (1/2)	1.17	0.98	0.98	1.21	1.05	1.06	1.13	1.32	1.49	1.59	1.60
5 Major New Generation & Transmission	1 374.7	2 012.8	2 746.5	2 376.2	1 460.5	895.3	460.7	325.1	151.6	109.0	109.1
6 Financing Required to Fund MNG&T	1 279.0	2 022.7	2 757.5	2261.7	1432.3	860.0	387.4	145.9	0.0	0.0	0.0

For the year ended March 31	Forecast 2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1 Cash Flow from Operations	1 007.1	1 136.6	1 237.1	1 370.0	1 465.8	1 548.9	1 671.0	1 762.5	1 865.9	1 986.6
2 Sustaining Capital Spending	624.5	637.3	648.6	674.7	661.1	703.5	710.5	719.6	734.9	809.6
3 Excess Cash Flow after Sustaining Capital Spending (1-2)	382.6	499.4	588.5	695.3	804.7	845.5	960.4	1042.9	1131.0	1177.1
4 Capital Coverage Ratio (1/2)	1.61	1.78	1.91	2.03	2.22	2.20	2.35	2.45	2.54	2.45
5 Major New Generation & Transmission	114.9	129.7	122.1	117.5	107.6	114.9	120.0	133.9	187.5	279.0
6 Financing Required to Fund MNG&T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Section:	1 7 Attachment 20	Page No.:	7 50 2
Topic:	Capital Spending		
Subtopic:	2014/15 Forecast vs. Actuals		
Issue:	Reconciliation		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide a schedule that breaks down, by project, any variances between the CEF14 forecast capital spending for 2014/15 and the actual capital spending that are greater than $3 M and provide an explanation

RATIONALE FOR QUESTION:

To clarify actual 2014/15 capital spending and understand reasons for variance from previous GRA forecast.

RESPONSE:

The following table provides a breakdown by project of all 2014/15 variances greater than $3 million between the CEF14 forecast and actual spending.

MANITOBA HYDRO CAPITAL EXPENDITURES
VARIANCEs >$3M
(in millions)

	Actual	Forecast (CEF14)	Variance	EXPLANATION
Major New Generation & Transmission				
Wuskwatim - Generation	30.8	40.5	9.7	Wuskwatim - Generation under expenditure of $9.7 million was mainly due to negotiations regarding the general civil contract which resulted in a lower final settlement.
Keeyask - Generation	696.7	765.5	68.7	Keeyask Generation under expenditure of $68.7 million was primarily due to a schedule delay in the construction of the main camp which also resulted in a deferral of the work area site development. In addition, there were lower than anticipated contract prices for the intake & spillway gates, guides and hoists.
Keeyask - Transmission	7.7	10.8	3.2	Keeyask Transmission under expenditure of $3.2 million was primarily due to the deferral of foundation installation to next winter as a result of internal resource constraints caused by Bipole III scheduling.
Conawapa - Generation	37.4	43.4	6.0	Conawapa - Generation under expenditure of $6.0 million was primarily due to delays in execution of work required for wind-down of the project including engineering, environmental assessment coordination and various environmental studies. These delays are as a result of internal as well as external resource constraints. In addition, there were delays in executing the Aboriginal Traditional Knowledge agreements.
Pointe du Bois Spillway Replacement	119.9	114.1	(5.8)	Pointe du Bois Spillway Replacement Project over expenditure of $5.8 million was primarily a result of severe weather events at the construction site, record flows on the Winnipeg River and quality issues with the supply of equipment.
Pointe du Bois - Transmission	13.0	15.8	2.8	Pointe Du Bois Transmission under expenditure of $2.8 million was primarily due to contractor delays for the installation of the transformer fire protection deluge sprinkler system as well as lower than anticipated costs associated with design changes, contractor or material delays and price fluctuations.
Gillam Redevelopment & Expansion Program	12.0	20.0	8.0	Gillam Redevelopment & Expansion Program (GREP) under expenditure of $8.0 million was mainly due to a partial curtailment on spending and a delay as a result of re-analysis of the needs assessment and redevelopment of an overall plan to optimize resources.
Bipole III - Transmission Line	128.3	203.5	75.1	Bipole III – Transmission Line under expenditure of $75.1 million was primarily due to construction activities starting later than anticipated due to above average winter temperatures.
Bipole III - Converter Stations	201.8	221.1	19.3	Bipole III – Converter Stations under expenditure of $19.3 million was primarily due to delayed completion of construction of the Keewatinohk Camp and associated infrastructure. The delay has not impacted construction of the Keewatinohk Converter Station site.
Bipole III - Collector Lines	35.1	58.4	23.3	Bipole III – Collector Lines under expenditure of $23.3 million was primarily due to delayed foundation and anchor materials procurement and lower than anticipated construction costs due to both an updated construction schedule and work being completed below budget.
Riel 230/500 kV Station	30.5	36.4	5.9	Riel 230/500 kV Station under expenditure of $5.9 million was primarily due to a unused contingency associated with schedule, contractor or material delays, and price fluctuations.

Major Items	Actual	Forecast (CEF14)	Variance	
Rockwood New 230 - 115 kV Station	22.1	26.6	4.5	Rockwood New 230 – 115kV Station under expenditure of $4.5 million was primarily due to delays in communication and teleprotection design and procurement as a result of competing customer prioritieis. In addition there were delays in design and material procurement under the Engineering, Procurement, Construction and Commissioning station contract as well as delays in transmission line construction as a result of contractor scheduling revisions.
Lake Winnipeg East System Improvement	8.8	14.2	5.4	Lake Winnipeg East System Improvement under expenditure of $5.4 million was primarily due to delays in acquiring environmental licenses which has deferred all station and transmission line clearing and construction activities.
New Madison Station - 115 24kV Station	27.3	32.6	5.3	Madison New Station 115 – 24kV Station under expenditure of $5.3 million was mainly due to delays in the Engineering, Procurement, Construction and Commissioning contract as a result of contractor scheduling revisions.

Section:	1	Page No.:	7
Topic:	Capital In-Service		
Subtopic:	Comparison of IFFs		
Issue:	Changes in Capital In-Service		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a graphic (similar to Figure 2.16 from the Tab 2 of 2015/16 & 2016/17 GRA) setting out the additional a capital in-service amount for each year from 2014/15 (actual) to 2024/25 based on IFF15.

b) Please provide a schedule that provides the annual values for the graphic requested in part (a) for each of i) Sustaining Capital, ii) New Generation and Transmission and iii) DSM and iv) Other Assets

c) In the same schedule requested in part (b) (or a separate schedule if necessary) please provide the comparable values from CEF14 as used in for Figure 2.16 from the last GRA.

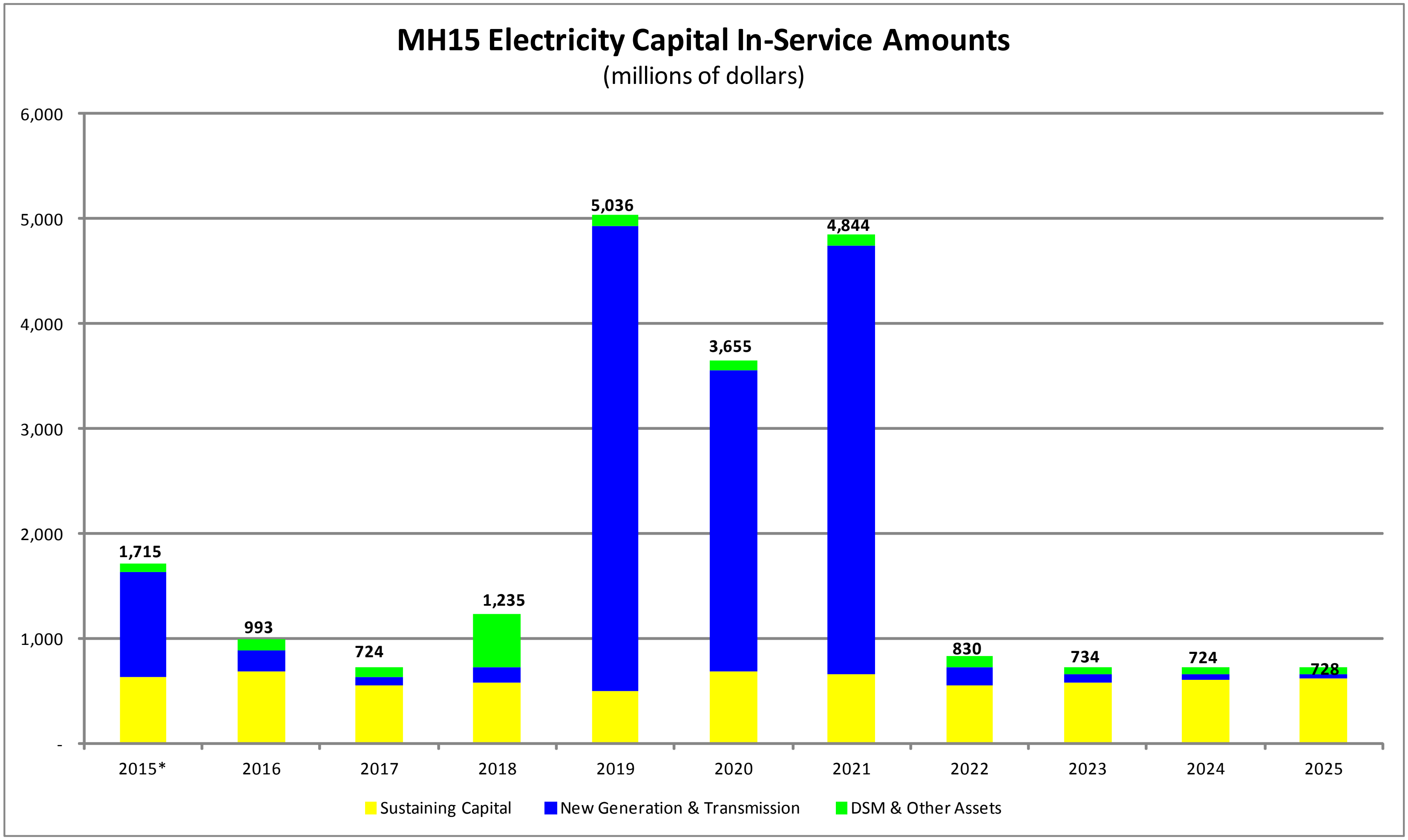
d) Please provide an explanation of any annual variances in in-service capital by expenditure category of more than 5%.

RATIONALE FOR QUESTION:

To compare capital in service additions in current application with those filed in the last GRA and understand the reasons for any material changes.

RESPONSE:

a) The following schedule provides MH15 capital in-service amounts from 2015 to 2025.



* Actual in-service amount in Fiscal year 2015

b) The following schedule provides MH15 annual capital in-service amounts requested in part a.

MH15 Capital In-Service Amounts (in millions of dollars)	**2015***	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Sustaining Capital	586	684	555	574	498	689	656	556	576	612	614
New Generation & Transmission	1 044	203	75	152	4 438	2 863	4 093	177	85	44	44
DSM	33	62	58	99	95	90	92	97	72	67	71
Other Assets	52	44	36	410	5	14	2	0	0	-	-
	1 715	993	724	1 235	5 036	3 655	4 844	830	734	724	728

* Actual in-service amount in Fiscal year 2015

c) The following schedule provides MH14 annual capital in-service amounts.

MH14 Capital In-Service Amounts (in millions of dollars)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Sustaining Capital	576	593	642	591	561	627	632	528	513	620
New Generation & Transmission	1,036	152	116	212	4,353	2,822	4,067	138	54	54
DSM	52	59	77	84	94	78	73	61	50	50
Other Assets	37	29	450	14	-	0	1	5	-	-
	1,700	833	1,283	901	5,007	3,527	4,773	731	617	723

d) The following schedules provide changes to in-service amounts between forecasts by category. The variance explanations on Sustaining, New Generation and Transmission, DSM and Other Assets for changes greater than 5% are provided below.

MH15 Less MH14 In-Service Amounts (in millions of dollars)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Sustaining Capital	20	91	(87)	(17)	(62)	62	24	28	63	(7)
New Generation & Transmission	(2)	51	(40)	(60)	85	41	27	39	31	(10)
DSM	(19)	3	(19)	15	1	12	20	36	22	18
Other Assets	15	15	(414)	396	5	14	1	(4)	0	-
	14	160	(559)	334	29	129	72	99	116	1

Percentage Variance	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Sustaining Capital	4%	15%	-14%	-3%	-11%	10%	4%	5%	12%	-1%
New Generation & Transmission	0%	34%	-35%	-28%	2%	1%	1%	28%	57%	-18%
DSM	-36%	5%	-24%	18%	1%	15%	27%	59%	45%	36%
Other Assets	40%	51%	-92%	2789%	100%	100%	NA	NA	NA	NA

Sustaining Capital Variances – Manitoba Hydro has hundreds of projects within Sustaining Capital which are placed in-service throughout the year. Due to unforeseen circumstances impacting schedule, timing of in-service can often vary from forecast. The following table provides examples of some projects with in-service amounts in variance from forecast.

Fiscal Year	Percentage Variance	Variance $M	Explanations
2016	**15%**	91	$30M Neepawa Station - The in-service date (ISD) was deferred to 2016 to coincide with the outage given for the line sectionalization work.. $25M Martin Station - The delay in in-service was a result of construction beginning later than forecast primarily due to delays in acquiring a portion of city owned property as a result of longer than anticipated negotiation of the servicing agreement (e.g. moving sewer, re-routing water, fire hydrant). $19M HVDC Transformer Replacement – The change reflects the advancement of two transformers from 2017 (Radisson & Henday Converter Stations).
2017	**-14%**	(87)	($64M) Lake Wpg East System Improvements - The in-service date was deferred to 2018 as a result of ongoing delays in obtaining an environmental licence. ($19M) HVDC Transformer Replacement ($19M) - The change reflects the advancement of two transformers to 2016 (Radisson & Henday Converter Stations). ($26M) Southwest Winnipeg 155kV Transmission Improvements – The change reflects a multi-year deferral to 2020 resulting from slower than anticipated load growth.
2019	**-11%**	(62)	($51M) St. Vital Station – The in-service date was advanced to 2018 to address capacity requirements. ($13M) Pointe du Bois Unit & Accessories Replacement - The decision to replace rather than refurbish the units resulted in a deferral of the ISD.

2020	**10%**	62	$47M Letellier-St. Vital 230kV Transmission – Based on an analysis of system risks, a decision to delay the start of construction of the new 230kV transmission line resulted in a deferral of the ISD to 2020. $26M Southwest Winnipeg 115kV Transmission Improvement - The change reflects a multi-year deferral to 2020 resulting from slower than anticipated load growth.
2023	**12%**	63	$25M Brandon Units 6&7 Overhaul Program – The ISD for Brandon Unit 6 was advanced based on an increase in operating hours which drive the overhaul schedule. $5M Point du Bois Unit & Accessories Replacement - The decision to replace rather than refurbish the units resulted in a deferral of the ISD to 2023.

New Generation and Transmission Variances

Fiscal Year	Percentage Variance	Variance $M	Examples
2016	**34%**	51	$50M Pointe du Bois Spillway Replacement – The ISD was deferred to 2016 primarily due to construction delays as a result of severe weather events at the construction site, record flows on the Winnipeg River and quality issues with the supply gate equipment.
2017	**-35%**	(40)	$30M Wuskwatim Staffhouse - Deferred to 2018 pending further review of requirements.
2018	**-28%**	(60)	($105M) Bipole III Transmission Line – CEF15 adjusted the ISD for the contingency forecast to align with the ISD of the project. Partially offset by: $30M Wuskwatim Staffhouse - Deferred to 2018 pending further review of requirements.
2022	**28%**	39	$57M Manitoba-Saskatchewan Transmission - New project which supports the 100MW system power sale to Saskatchewan. The new interconnection to Saskatchewan will also expand and diversify Manitoba Hydro's market access and customer base. Partially offset by: ($7M) Gillam Redevelopment and Expansion Project – Re-prioritization of the development plans impacted the ISD of various sub-projects resulting in the deferral of some and advancement of others.
2023	**57%**	31	$23M Gillam Redevelopment and Expansion Project - Re-prioritization of the development plans impacted the ISD of various sub-projects resulting in the deferral of some and advancement of others.
2024	**-18%**	(10)	($17M) Gillam Redevelopment and Expansion Project - Re-prioritization of the development plans impacted the ISD of various sub-projects resulting in the deferral of some and advancement of others.

Demand Side Management (DSM)

The change between the actual and forecasted in-service amounts in 2015 was primarily due to the delays in the LED Roadway Lighting Program and lower costs for the Performance Optimization Program.

The change in the forecast in-service amounts in 2017 was primarily due to the Load Displacement Program being delayed by one year and lower costs for the Performance Optimization Program.

The changes in the forecast in-service amounts for 2018 through 2024 are the result of additional requirements for various programs including Load Displacement, Other Emerging Technologies, and LED Roadway Lighting.

Other Assets Variances

The change between the actual and forecasted in-service amounts in 2015 was primarily related to Information Technology (IT) intangible assets being placed in-service earlier than previously forecast.

The change in the forecast in-service amounts in 2016 was primarily due to higher costs and advancements related to easements for Bipole III and other station or transmission lines. In addition, there was a re-scheduling of the ISD's for IT intangible assets.

The change in the forecast in-service amounts in 2017 and 2018 was primarily due to the deferral of the Conawapa ISD to 2018 to align with the revised timing of the project business case.

The change in the forecast in-service amounts in 2019 and 2020 was primarily due to an increase in easement costs for the Manitoba-Minnesota Transmission Line and a deferral of easements related to Letellier – St. Vital 230kV Transmission Line.

Section:	3 Manitoba Hydro 2014/15 Annual Report	**Page No.:**	17 89
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Annual Report		
Issue:	Comparison of Annual Report and Application		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please also reconcile the Electric Operations' 2014/15 revenues shown on page 17 ($1,843 M) with the Electricity Segment revenues reported in the Annual Report ($1,892 M).

b) Similarly, where there are differences, please reconcile the various individual 2014/15 expenses as shown on page 17 versus those reported in the Annual Report.

c) Overall, the 2014/15 net income shown on page 17 is $95 M whereas the value shown in the 2014/15 Annual Report for Electricity Segment net income is $104 M. Please reconcile.

RATIONALE FOR QUESTION:

To reconcile difference between actual 2014/15 financial results as set out in the Application with those shown in the 2014/15 Annual Report.

RESPONSE:

With respect to parts a) through c), the Electricity Segment in the 2014/15 Annual Report includes subsidiary revenues and expenses whereas the Electric Operation's 2014/15 shown in the 2016/17 Supplemental Filing excludes subsidiary revenues and expenses. The reconciliation is shown in the table below.

	2015 Annual Report	2015 Electric Operations	2015 Subsidiary Operations*
Revenue	1 892	1 843	50
Operating and administrative	492	480	12
Finance expense (income)	492	495	(2)
Depreciation and amortization	405	403	1
Water rentals and assessments	125	125	-
Fuel and power purchased*	145	146	-
Capital and other taxes	100	100	1
Other expense	31	2	29
Corporate allocation	9	9	-
Expenses	1 799	1 760	41
Non-controlling interest	11	11	-
Net income	104	95	9
*net of intercompany eliminations			

Section:	2	Page No.:	16
Topic:	Financial Ratio		
Subtopic:	Comparison of IFFs		
Issue:	Changes in Financial Ratios		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a figure similar to Figure 10 that sets out the same information for i) the actual results for 2014/15 and ii) IFF14 for the years 2014/15 to 2016/17.

RATIONALE FOR QUESTION:

Compare the current forecasts and actual 2014/15 results with IFF14.

RESPONSE:

The following tables compare key financial indicators for actual 2014/15 results, MH15 and MH14.

MH15

Retained Earnings and Financial Ratios (without proposed rate increase)	Actual 2015	Forecast 2016	2017
Net Income (electric operations)	$ 95	$ 15	$ (33)
Retained Earnings (electric operations)	$ 2 710	$ 2 612	$ 2 579
Debt to Equity Ratio (electric operations)	79:21	85:15	87:13
EBITDA Interest Coverage Ratio (electric operations)	1.80	1.57	1.45
Capital Coverage Ratio (electric operations)	1.16	0.98	0.88

Retained Earnings and Financial Ratios (including proposed rate increase)			
Net Income (electric operations)	$ 95	$ 15	$ 29
Retained Earnings (electric operations)	$ 2 710	$ 2 612	$ 2 641
Debt to Equity Ratio (electric operations)	79:21	85:15	86:14
EBITDA Interest Coverage Ratio (electric operations)	1.80	1.57	1.52
Capital Coverage Ratio (electric operations)	1.16	0.98	0.98

MH14

Retained Earnings and Financial Ratios (without proposed rate increases)	2015	Forecast 2016	2017
Net Income (electric operations)	$ 102	$ 58	$ (58)
Retained Earnings (electric operations)	$ 2 717	$ 2 721	$ 2 663
Debt to Equity Ratio (electric operations)	78:22	82:18	85:15
EBITDA Interest Coverage Ratio (electric operations)	1.79	1.64	1.42
Capital Coverage Ratio (electric operations)	0.98	0.92	0.74

Retained Earnings and Financial Ratios (including proposed rate increase)	2015	2016	2017
Net Income (electric operations)	$ 102	$ 115	$ 59
Retained Earnings (electric operations)	$ 2 717	$ 2 778	$ 2 837
Debt to Equity Ratio (electric operations)	78:22	82:18	84:16
EBITDA Interest Coverage Ratio (electric operations)	1.79	1.72	1.56
Capital Coverage Ratio (electric operations)	0.98	1.02	0.94

Section:	3 Attachment 16	**Page No.:**	17 1
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Extraprovincial Revenues		
Issue:	Reconciliation of Reported Values		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Figure 11 reports actual 2014/15 extraprovincial revenues of $400 M, whereas Attachment 16 reports a total value of $384 M ($38.2 M + $345.5 M). Please reconcile.

RATIONALE FOR QUESTION:

Reconcile differences in reported actual extraprovincial revenues for 2014/15

RESPONSE:

Extraprovincial revenue is the sum of Canadian and US export revenues, merchant sales, transmission credits and environmental credits as indicated in the table below. Attachment 16 only reported on the sum of Canada and US export revenues.

(in millions of dollars)	**2014/15**
Total export revenues to Canada	38.2
Total export revenues to USA	345.5
Merchant sales	11.4
Transmission credits	2.3
Environmental credits	2.8
Extraprovincial Revenues	**400.2**

Section:	3 Attachment 16 2015/16 & 2016/17 GRA Appendix 11.19	**Page No.:**	17 & 18 1 3
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Extraprovincial Revenues		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a table similar to that in Attachment 16 (page 1) but based on the forecast for 2014/15 per IFF14. (Note: If necessary for reasons of confidentiality, the values for firm and opportunity sales can be combined for purposes of reporting volumes, revenues and average price).

RATIONALE FOR QUESTION:

Compare actual 2014/15 results with forecast in last GRA.

RESPONSE:

Please see attached table.

FORECAST AVERAGE UNIT REVENUE/COST CALCULATION IFF14

VOLUMES (in GW.h)	2014/15
Firm & Opportunity Export Sales to Canada	851
Firm & Opportunity Export Sales to Canada (less Lake St Joseph Volumes)	802
Firm & Opportunity Export Sales to US	9184
Purchased Energy	1098
REVENUE/COST (in milions of dollars)	
Total Export Sales to Canada	28.748
Total Export Sales to USA	343.003
Net Transmission Charges	25.515
Total Export Sales to USA (incl. Net Transmission Charges)	317.488
Purchased Energy (including Assessments)	75.844
AVERAGE UNIT REVENUE/COST ($/MW.h))	
Total Export Sales to Canada	35.86
Total Export Sales to USA (includes Net Trans Credits)	34.57
Total Export Sales	34.67
Import Energy Including Wind	69.06

Section:	3 Attachment 16 2015/16 & 2016/17 GRA Appendix 11.19	**Page No.:**	17 & 18 1 3
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Extraprovincial Revenues		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Appendix 11.19 from the last GRA reported average unit revenue from export sales for 2014/15 of $34.67/MWh. Attachment 16 in the current Application indicates that the actual average unit revenues were $38.33 / MWh overall and $26.36 / MWh, including net Transmission and Enviro charges – based on summing revenues and dividing by total volumes.

i. Which of the two values calculated from Attachment 16 is comparable to the $34.67/MWh value from the last GRA?

ii. Are the reported actual extraprovincial revenues of $400 M and the IFF14 forecast amount of $409 M both net of the Transmission and Enviro charges?

iii. Please explain the variance between the 2014/15 actual and forecast average unit revenues from extraprovincial sales.

RATIONALE FOR QUESTION:

Compare actual 2014/15 results with forecast in last GRA.

RESPONSE:

On January 21, 2016, Manitoba Hydro filed a revised Attachment 16 as the value for "Total Export Sales to USA (including Transmission and Environmental charges)" was inadvertently listed as $225.635 million. The correct value is $315.091 million. This correction results in a revised calculation of average unit revenues to $35.29/MWh when net Transmission and Environmental charges are included.

The following responses are based on the corrected numbers in Attachment 16.

i) The $34.67/MWh value from last GRA (Appendix 11.19) is comparable to the $35.29/MWh calculation when net Transmission and Environmental charges are included.

ii) Neither actual extraprovincial revenues of $400M or the IFF14 forecast extraprovincial revenues of $409M include Transmission and Environmental charges. They are calculated solely on sales revenues and volumes.

iii) Manitoba Hydro's reporting standard for actual average prices differs from the calculation of forecast average unit revenue provided in Attachment 16. This is because Attachment 16 is in the form prescribed by the PUB where forecast average unit revenues are calculated net of transmission credits and charges.

The table below shows a comparison of average unit energy revenue based on sales data for 2014/15.

	Actual	**IFF-14**
Export Sales (GWh)	10010	9985
Export Sales (millions CAD$)	378.578	371.751
Average Unit Energy Revenue ($/MWh)	**37.82**	**37.23**

The actual export sales of $378.578M in the above table differs from that shown in Attachment 16 as the amount in Attachment 16 includes non-energy related revenues.

The actual average price appears higher than IFF-14 however this is due to a change in exchange rate. The average US sales price in US$ is actually lower than IFF14.

Section:	3 Attachment 16 2015/16 & 2016/17 GRA, Tab 5, Schedule 5.1.8	Page No.:	18 1 34
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Fuel and Power Purchases		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a breakdown of actual 2014/15 Fuel and Power Purchases in a format similar to that in Schedule 5.1.8 from the last GRA.

RATIONALE FOR QUESTION:

Compare actual 2014/15 results with forecast in last GRA.

RESPONSE:

The following table provides a breakdown of fuel and power purchases.

		2014/15 Actual
(000's)		
Thermal Fuel		
Coal	$	3 171
Natural Gas & Other		7 029
Power Purchased		84 535
Merchant Purchases		15 585
Transmission Charges		35 449
	$	145 769

Section:	3 Attachment 16 2015/16 & 2016/17 GRA, Tab 5, Schedule 5.1.8	**Page No.:**	18 1 34
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Fuel and Power Purchases		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide the forecast (IFF14) and actual 2014/15 power purchase volumes and resulting average cost per MWH.

RATIONALE FOR QUESTION:

Compare actual 2014/15 results with forecast in last GRA.

RESPONSE:

Actual average prices and IFF14 average prices for purchased energy are provided in the following table for 2014/15.

	Actuals	IFF14
Power Purchases (GWh)	1382	1098
Purchased Energy (millions CAD$)	83.228	70.910
Average Unit Cost ($/MWh)	**60.22**	**64.58**

The Purchased Energy Actuals of $83.228M in the above table differs from that shown in Attachment 16 Total Import Energy as the amount shown there includes all market charges.

The Average Unit Cost of $64.58/MWh for IFF14 in the table above differs from that shown on Attachment 16 as the amount shown there includes Assessments, which costs are unrelated to the purchase cost of energy.

Section:	3 Attachment 16 2015/16 & 2016/17 GRA, Tab 5, Schedule 5.1.8	**Page No.:**	18 1 34
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Fuel and Power Purchases		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide a schedule the compares the overall energy supply/demand balance (i.e. total GWh demand broken down as between domestic sales, exports and losses versus sources of supply broken down as between hydro generation, thermal generation and purchases) for 2014/15 as between that forecast in IFF14 versus actual.

RATIONALE FOR QUESTION:

Compare actual 2014/15 results with forecast in last GRA.

RESPONSE:

IFF14 supply and demand values are compared to actual results for 2014/15 in the following table:

		IFF14	Actual	Variance (Actual - IFF14)
Supply (GWh)	Hydraulic	35,116	34,975	-141
	Thermal	101	69	-32
	Purchases	1,098	1,191	93
	Total	36,315	36,235	-80
Demand (GWh)	Manitoba[1]	25,321	25,531	210
	Export	10,035	9,811	-224
	Net Losses	958	893	-65
	Total	36,315	36,235	-80

Notes:

1. Includes station service.

Section:	3 Manitoba Hydro 2014/15 Annual Report	**Page No.:**	17 36
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Revenues		
Issue:	Reconciliation of Reported Values		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please reconcile the $68 M in other revenues for 2014/15 as shown in the Annual report with the $18 M value set out in the current Application.

RATIONALE FOR QUESTION:

Reconcile differences in reported actual other revenues for 2014/15.

RESPONSE:

The $68 million in other revenue for 2014/15 as shown in the Annual Report includes subsidiary revenue. The $18 million in the current Application is Electric Operations, which excludes subsidiaries.

Section:	3 2015/16 & 2016/17 GRA Appendix 3.3 Manitoba Hydro 2014/15 Annual Report	Page No.:	17 30, 38 and 40 58 and 89
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Financial Statements		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the actual 2014/15 statement of cash flow for electric operations in a format comparable to forecast provided in IFF14 (page 40).

RATIONALE FOR QUESTION:

Actual borrowing in 2014/15 was higher than forecast even though it appears actual funds required were lower than forecast. Question seeks to understand why and the impact on financial results reported for 2014/15. Similarly, actual net income for 2014/15 is less than forecast but year-end retained earnings are higher. Question seeks to understand why.

RESPONSE:

Please refer to statement below:

ELECTRIC OPERATIONS
CASH FLOW STATEMENT
(In Millions of Dollars)

For the year ended March 31, 2015

	Actual
OPERATING ACTIVITIES	
Cash receipts from customers	1 877
Cash paid to suppliers and employees	(750)
Interest paid	(503)
Interest received	31
	655
FINANCING ACTIVITIES	
Proceeds from long-term debt	2 175
Sinking fund withdrawals	110
Retirement of long-term debt	(619)
Other	(38)
	1 628
INVESTING ACTIVITIES	
Property, plant and equipment	(1 698)
Sinking fund payments and deposits	(114)
Other	(120)
	(1 932)
Net Increase in Cash	351
Cash at Beginning of Year	131
Cash at End of Year	482

Section:	3 2015/16 & 2016/17 GRA Appendix 3.3 Manitoba Hydro 2014/15 Annual Report	**Page No.:**	17 30, 38 and 40 58 and 89
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Financial Statements		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide the actual 2014/15 balance sheet for electric operations in a format comparable to the forecast provided in IFF14 (page 38).

RATIONALE FOR QUESTION:

Actual borrowing in 2014/15 was higher than forecast even though it appears actual funds required were lower than forecast. Question seeks to understand why and the impact on financial results reported for 2014/15. Similarly, actual net income for 2014/15 is less than forecast but year-end retained earnings are higher. Question seeks to understand why.

RESPONSE:

The 2014/15 electric operations balance sheet is as follows:

Manitoba Hydro
Electric Operations Balance Sheet
As at March 31, 2015
(In millions of dollars)

	2015
ASSETS	
Plant in Service	$ 17 012
Accumulated Depreciation	(5 567)
Net Plant in Service	11 445
Construction in Progress	3 298
Current and Other Assets	2 196
Goodwill and Intangible Assets	220
Regulated Assets	229
	$ 17 388
LIABILITIES AND EQUITY	
Long-term debt	$ 12 286
Current and Other Liabilities	1 996
Contributions in Aid of Construction	388
BPIII Reserve Account	49
Non-controlling Interest	120
Retained Earnings	2 710
Accumulated Other Comprehensive Income	(161)
	$ 17 388

Section:	3 2015/16 & 2016/17 GRA Appendix 3.3 Manitoba Hydro 2014/15 Annual Report	Page No.:	17 30, 38 and 40 58 and 89
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Financial Statements		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) The actual cash flow statement for the Corporation (Annual Report, page 58) shows (versus IFF14, page 30) an increase in cash provided by operating activities and also a decrease in cash required for investing. However, borrowing has increased over forecast such that there is an increase of over $500 M in actual cash and cash equivalents at year end versus the forecast in IFF14. Please explain the reason the increased borrowing and why, instead, actual borrowing was not reduced from that originally forecast.

d) What is the impact of this higher level of borrowing on the electric operations interest expense for 2014/15 as compared to if the actual borrowing for 2014/2015 had be just sufficient to result in Cash at End of Year equivalent to that in the IFF14 (Last GRA, Appendix 3.3, page 30)?

RATIONALE FOR QUESTION:

Actual borrowing in 2014/15 was higher than forecast even though it appears actual funds required were lower than forecast. Question seeks to understand why and the impact on financial results reported for 2014/15. Similarly, actual net income for 2014/15 is less than forecast but year-end retained earnings are higher. Question seeks to understand why.

RESPONSE:

c) Please see Manitoba Hydro's response to PUB/MH-I-30a.

d) The financing secured in the fourth quarter of 2014/15 took advantage of exceptional financial market opportunities to secure debt financing with the lowest fixed rate long bond yield rates in the Corporation's history. The financial benefits associated with this financing are estimated to be in excess of $27 million, as noted in response to PUB/MH I-30a.

Section:	3 2015/16 & 2016/17 GRA Appendix 3.3 Manitoba Hydro 2014/15 Annual Report	**Page No.:**	17 30, 38 and 40 58 and 89
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Financial Statements		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

e) The actual 2014/15 net income for the Electric Operations is less than forecast (page 17). However, the actual retained earnings for the Electricity Segment (Annual Report, page 89) are higher than forecast in IFF14. Please reconcile.

RATIONALE FOR QUESTION:

Actual borrowing in 2014/15 was higher than forecast even though it appears actual funds required were lower than forecast. Question seeks to understand why and the impact on financial results reported for 2014/15. Similarly, actual net income for 2014/15 is less than forecast but year-end retained earnings are higher. Question seeks to understand why.

RESPONSE:

The electricity segment retained earnings of $2 758 million as reported in the Annual Report includes $48 million of retained earnings from subsidiary operations. After removing subsidiary retained earnings, the resulting retained earnings for electric operations is $2 710 million. This is $7 million lower than IFF14 and is consistent with the net income variance reported on page 17 of the 2016/17 Supplemental Filing.

Section:	Attachment 37 2015/16 & 2016/17 GRA, Appendix 11.38	**Page No.:**	2 2
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Interest Expense		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide schedules that set out the calculation of both the forecast (per IFF14) and actual 2014/15 Gross Interest Expense. In doing so please indicate: i) the total amount of debt involved in each case, ii) the new debt issued in 2014/15, iii) the interest rates associated with pre-2014/15 and 2014/15 debt; and iv) impact of foreign exchange.

d) Please explain why, for Electric Operations, the actual Gross Interest Expense for 2014/15 is virtually the same as in IFF14, even though actual borrowing 2014/15 was significantly higher than forecast.

RATIONALE FOR QUESTION:

To understand the difference between forecast and actual 2014/`15 results.

RESPONSE:

Response to part a) and d):

Gross interest expense for the fiscal year represents the summation of the each month's accrued interest payments for each debt series within the entire debt portfolio, along with other income from temporary investments & loans, and the monthly revaluation of USD interest payments and cash balances into CAD. Each month, the debt portfolio's gross interest expense will be dynamically updated according to changes affecting the volume of debt outstanding for each debt series (net of retirements, redemptions, refinancings and new issuance), the applicable interest rates for each debt series (including adjustments as required for the periodic resetting of interest rates on floating rate debt), the amount of temporary investments & loans outstanding, and the conversion of USD interest payments and cash balances into CAD (using month-end USD/CAD exchange rates).

Given the integrated nature of the calculation of gross interest expense, it is impractical to decompose it into the component parts requested. However, to assist in the understanding of gross interest expense, the following schedule provides aggregated information according to major categories within the debt portfolio:

MANITOBA HYDRO	**Actual**	**IFF14**	**Variance**
Gross Interest Expense ($ millions CAD)	**2015**	**2015**	**2015**
Canadian Fixed Rate Interest	403	398	5
Canadian Floating Rate Interest	37	36	1
US Fixed Rate Interest	138	132	6
US Floating Rate Interest	1	1	(0)
Interest Income and Other	(27)	(13)	(14)
Gross Interest Expense	**552**	**554**	**(2)**

As indicated in the schedule, for 2014/15 the actual gross interest expense of $552 million was $2 million less than the $554 million forecast in IFF14 for electric operations. Although actual borrowing in 2014/15 was higher than forecast, the debt volume impact on gross interest expense was partially offset by lower actual interest rates and higher actual temporary investment earnings due to investing cash proceeds. As the USD/CAD exchange rate was higher on an actual basis than forecast, the interest expense associated with the conversion of USD interest payments to CAD was higher than forecast; however, the revaluation of USD bank balances into CAD within the Interest Income and Other category more than offset the currency conversion of USD interest expense during 2014/15.

Section:	Attachment 37 2015/16 & 2016/17 GRA, Appendix 11.38	**Page No.:**	2 2
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Interest Expense		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

b**)** Please provide schedules that set out the calculation of both the forecast (per IFF14) and the actual 2014/15 Interest Allocated to Construction and that indicate both the total assets under construction and the interest rate used. Please also indicate the basis for the interest rate used in the calculation.

RATIONALE FOR QUESTION:

To understand the difference between forecast and actual 2014/15 results.

RESPONSE:

Manitoba Hydro calculates interest allocated to construction by applying the interest capitalization rate to the actual or forecast previous month-end construction in progress balance of each project, until such project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Interest capitalized for each project is then aggregated to form total interest allocated to construction. Due to the hundreds of capital projects attracting capitalized interest, it is impractical to provide the calculation of actual and forecast capitalized interest for each project.

Actual interest allocated to construction for 2014/15 was $145.9 million compared to the forecast of $145.6 for a favourable variance of $0.3 million or 0.21%. The interest capitalization rate for 2014/15 is 5.89% for both actual and forecast for all electric capital projects except Keeyask (as explained below). As a result, the change in interest allocated to construction from forecast to actual for 2014/15 for projects except Keeyask is due entirely to changes in actual capital expenditures and in-service additions from forecast. The responses to COALITION/MH-I-1 and COALITION/MH-I-3 provide comparisons of capital expenditures and in-service additions for 2014/15.

Commencing in August 2014 for Keeyask, all interest costs in the Keeyask Hydropower Limited Partnership are capitalized since there is only the one asset under construction in the partnership. Interest is charged to the partnership based on the current market interest rates as at the date of each advance. In addition, Manitoba Hydro capitalizes interest on the Corporation's equity contribution to the partnership at the interest capitalization rate of 5.89%. Costs incurred prior to August 2014 attracted interest at Manitoba Hydro's interest capitalization rates in the period costs are incurred. Please note that variances in interest allocated to construction for Major New Generation and Transmission projects are largely offset by the interest capitalized attributable to the target cost flow adjustment.

Section:	Attachment 37 2015/16 & 2016/17 GRA, Appendix 11.38	**Page No.:**	2 2
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Interest Expense		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please explain why the actual interest allocated to construction in 2014/15 ($146 M per Attachment 37) is equal to the IFF14 forecast interest allocated to construction (per Last GRA, Appendix 1.38) when the level of actual level of capital spending in 2014/15 was less than forecast.

RATIONALE FOR QUESTION:

To understand the difference between forecast and actual 2014/`15 results.

RESPONSE:

Interest allocated to construction is calculated on the work in progress balance of each project, and as such, changes in annual cash flow expenditures and timing of project in-service dates compared to forecast will impact the actual interest capitalized. Manitoba Hydro has hundreds of capital projects which range in duration from a few months to multiple years, vary in value and can have one to many in-service dates.

In 2014/15, the additional interest capitalization that results from the delay of the in-service for various projects (e.g. Riel 230/500 kV Station), in addition to increased costs for some projects (e.g. Pointe du Bois Spillway Replacement) were offset by the under expenditures in other projects (e.g. Bipole III).

Section:	Attachment 32	Page No.:	1 & 3
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Capitalized Labour & Benefits and Overhead		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain why actual labour and benefits charged to capital for 2014/15 is higher than forecast (Attachment 32) when the level of actual capital spending was less than forecast (per page 50)

b) Please explain why actual capitalized overhead for 2014/15 is higher than forecast (Attachment 32) when the level of actual capital spending was less than forecast (per page

RATIONALE FOR QUESTION:

Reconcile increase in capitalized overhead for 2014/15 (versus forecast) with decrease in capital spending.

RESPONSE:

a) There is not a direct correlation between capital project under expenditures and the level of labour and benefits charged to capital. Capital project forecasts and actual results are comprised of many costs not related to internal labour such as contracted services, materials, consulting, etc. Capital activity charges, which include labour and benefit costs represents approximately 15% of the total capital expenditure forecast.

b) Overhead costs, such as corporate services and departmental support functions, are pooled and allocated as a percentage add-on to activity charges. The capitalized overhead allocation is proportionate to the internal labor charged to capital projects and as such, the variance in 2014/15 is consistent with capital activity charges.

Section:	Attachment 32 Attachment 34 2015/16 & 2016/17 GRA Appendix 5.5	Page No.:	3 2 10 &11
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Labour Costs		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain why the actual 2014/15 sub-total for Wages& Salaries, Overtime and Employee benefits is higher than forecast ($727.6 M vs. $725.0 M) when the total number of actual ETF's for year (Straight Time plus Overtime) were less (6,713 vs. 6,864 {6,475+389} per Appendix 5.5).

RATIONALE FOR QUESTION:

To reconcile increase in actual 2014/15 labour costs over forecast when ETFs are lower.

RESPONSE:

Wages & salaries and overtime costs are directly impacted by changes in EFT levels. Changes in benefit costs as compared to forecast are impacted by other factors such as changes in discount and mortality rates and vacation usage. The actual benefit costs in 2014/15 were higher than forecast primarily due to the change in the discount rate.

The table below demonstrates the correlation of wages & salaries expenditures with straight time EFTs and overtime expenditures with overtime EFTs.

MANITOBA HYDRO
WAGE & SALARIES, OVERTIME AND EFTS

	2014/15 Actual	2014/15 Forecast	2014/15 Variance
Wages & Salaries*	493,346	502,692	9,346
ST EFT's	6,287	6,475	188
Overtime*	69,541	61,709	(7,832)
OT EFT's	426	389	(37)

*Expenditures are in thousands of dollars

Section:	Attachment 32	**Page No.:**	3
Topic:	Actual 2014/15 Financial Results		
Subtopic:	Non-Labour Costs		
Issue:	Variance from Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) It is noted that the O&A cost variance as between 2014/15 forecast and actual costs is attributable primarily to lower other costs charged to operations. Is this reduction in other costs (relative to forecast) sustainable for the years 2015/16 and 2016/17? If not, why not?

b) Is this reduction sustainable for the next 10 years? If not, why not?

RATIONALE FOR QUESTION:

To understand sustainability of 2014/15 cost savings.

RESPONSE:

The favorable variance to forecast in 2014/15 was primarily attributable to lower wages & salaries and other staffing related costs (i.e. travel, training, office supplies) resulting from the advancement of position reductions throughout the year. Other favorable variances for materials & tools and construction maintenance services are driven by other factors such as outage schedules and weather. These savings were partially offset by higher benefit costs as a result of a lower market driven discount rate and higher overtime costs for streetlight maintenance and storm restoration.

As discussed in the 2015/16 & 2016/17 GRA, the Corporation has implemented a number of cost savings initiatives focusing primarily on the reduction of operational positions in order to limit the committed 1% average annual increase in O&A costs over the 2014/15 through

2016/17 period. While these reductions assist the corporation in meeting its O&A targets through to 2016/17, Manitoba Hydro is reviewing other options, including additional EFT reductions in order to meet the O&A targets forecasted in MH15 beyond 2016/17.

Section:	4 2015/16 & 2016/17 GRA Appendix 3.3	Page No.:	24 36
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	General Consumer Revenues		
Issue:	Comparison of Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule that for each of the years 2015/16 through 2024/25 compares IFF14 and IFF15 with respect to :
   - Forecast General Consumer volumes (before forecast DSM savings). Note: It is understood that savings attributable to DSM programs implemented in 2014/15 will not be reflected in these volumes for IFF14; however they are for IFF15. To allow comparisons, please indicate the level of DSM savings assumed in IFF14 for each of these years from DSM programs implemented in 2014/15.
   - Forecast General Consumer volumes (after forecast DSM savings).
   - The Total General Consumer Revenues
   - The General Consumer Revenues accruing to the BPIII deferral account.

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

The schedule below compares MH15 and MH14 general consumer volumes before and after DSM savings, total general consumers revenue, and general consumer revenues accruing to the BPIII deferral account. To adjust MH14 for comparisons to MH15, planned 2014/15

DSM savings of 152 GW.h have been reflected in the gross general consumer volumes and DSM savings for IFF14 for the years 2015/16 to 2024/25.

	GCR Volumes before Forecast DSM Savings (GW.h)			DSM Savings (GW.h)			GCR Volumes After Forecast DSM Savings (GW.h)		
	IFF15	IFF14 *	Diff	IFF15	IFF14 *	Diff	IFF15	IFF14**	Diff
2016	22 785	22 739	46	(192)	(281)	88	22 593	22 458	134
2017	23 433	23 001	432	(365)	(543)	178	23 068	22 459	610
2018	23 729	23 670	60	(759)	(789)	30	22 971	22 881	89
2019	24 046	24 112	(67)	(1 096)	(1 102)	6	22 949	23 010	(61)
2020	24 175	24 639	(464)	(1 470)	(1 388)	(82)	22 705	23 251	(546)
2021	24 941	24 935	6	(1 723)	(1 616)	(107)	23 218	23 319	(101)
2022	25 270	25 247	23	(1 981)	(1 788)	(193)	23 289	23 459	(170)
2023	25 632	25 552	80	(2 129)	(1 888)	(240)	23 503	23 664	(161)
2024	25 978	25 854	124	(2 268)	(1 985)	(283)	23 710	23 869	(159)
2025	26 338	26 157	181	(2 398)	(2 057)	(341)	23 940	24 100	(160)

* *To allow for comparisons, DSM savings of 152 GW.h attributable to programs implemented in 2014/15 have been reflected in the volumes for IFF14 for the years 2015/16 to 2024/25.*

** *Unchanged from IFF14 Net Load Forecast*

	Total GCR Revenues ($ millions)			BPIII Deferral Account ($ millions)		
	IFF15	IFF14	Diff	IFF15	IFF14	Diff
2016	$ 1 517	$ 1 512	$ 5	$ 54	$ 32	$ 22
2017	$ 1 617	$ 1 578	$ 39	$ 67	$ 34	$ 33
2018	$ 1 678	$ 1 665	$ 12	$ 69	$ 36	$ 34
2019	$ 1 743	$ 1 740	$ 2	$ 21	$ 11	$ 10
2020	$ 1 800	$ 1 822	$ (22)	$ -	$ -	$ -
2021	$ 1 901	$ 1 900	$ 1	$ -	$ -	$ -
2022	$ 1 981	$ 1 985	$ (4)	$ -	$ -	$ -
2023	$ 2 076	$ 2 080	$ (4)	$ -	$ -	$ -
2024	$ 2 176	$ 2 179	$ (3)	$ -	$ -	$ -
2025	$ 2 282	$ 2 285	$ (3)	$ -	$ -	$ -

Section:	2 4 Attachment 16 2015/16 & 2016/17 GRA, Appendix 11.19	**Page No.:**	13 25 2 3
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Extraprovincial Revenues		
Issue:	Comparison of Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain the change in reporting treatment of transmission credits in IFF15 (per page 25, lines 11-13). In particular, please address the following:
   i. What precisely is the change from the practice used in IFF14?
   ii. For the Transmission credits related to intra-business transactions that are removed from extraprovincial revenues where, if at all, are they included in the Electric Operations operating statement? And
   iii. Does this change impact at all on the Electric Operation forecast net income for 2015/16 and 2016/17 and, if so, by how much?

b) With respect to Figure 8 (page 13), please provide the values for the total variance in each of the years 2015/16 through 2034/35, along with the values for each of contributing components – price, volume, US exchange and change in treatment of transmission credits (per page 25).

c) Is the $12 M reduction in extraprovincial revenue for 2015/16 that is attributed to higher opportunity/lower dependable sales captured in the overall $52 M reduction attributed to lower prices? If not, why not?

d) The Application indicates (page 25, lines 29-30) that in the first 10 years of IFF15 export volumes are higher due to lower Manitoba load. However, a comparison of the domestic volumes for 2016-2025 from IFF15 (Attachment 16) versus IFF14 (Appendix 11.19) suggests that total cumulative Manitoba volumes overall are not that much different nor are cumulative export volumes. Please explain the basis for the statement.

e) Based on IFF15, for what years over the 2015/16 to 2033/34 period is the unit revenue lost due to DSM greater than the unit revenues achieved through higher export sales.

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

a) In MH14, projected extraprovincial revenues reflected transmission revenues from MISO for the use of Manitoba Hydro transmission or rights by MISO members. A portion of these revenues are attributable to Manitoba Hydro for the use of Manitoba Hydro's own transmission facilities and Manitoba Hydro makes corresponding payments to MISO which were reflected in transmission charges in fuel and power purchased in MH14. When MH14 expenses are deducted from revenues to calculate net income, the portion of transmission revenues and charges attributable to Manitoba Hydro's own use of its transmission facilities are offset and there is no net impact to the Electric Operation forecast of net income.

   MH15 achieves the same net effect by eliminating the Manitoba Hydro attributed transmission credits from extraprovincial revenues and the Manitoba Hydro attributed transmission charges from fuel and power purchased resulting in the same no net impact to the Electric Operation forecast of net income. The remaining transmission revenues and charges reflect only payments to and from non-Manitoba Hydro MISO members.

b) When analyzing the variances in extraprovincial revenue and fuel and power purchased from MH14 to MH15, the elimination of the intercompany transmission revenues and charges must be considered; however, there is no variance due to the elimination of intercompany transmission revenues and charges on a net extraprovincial revenue basis.

The following table provides the data supporting the net extraprovincial revenue variances from MH14 to MH15 as depicted in Figure 8 (page 13) with U.S. exchange and other split out. The 'Other' category in the table below includes variances due to non-volume related revenues and costs as well as the impact of the elimination of a 200MW point to point transmission reservation commencing in 2017 which is partially offset by an increase in MISO Transmission tariffs commencing in 2016.

Net Extraprovincial Revenues - Comparison MH15 vs MH14
(in millions of dollars)

	Variance due to:				
Fiscal Yr Ending	Price	Volume	Other	FX	Total
2016	(53.5)	(3.9)	(18.1)	43.8	(31.7)
2017	(96.7)	43.7	0.2	45.4	(7.4)
2018	(10.3)	(10.0)	(0.5)	32.9	12.0
2019	(9.5)	3.3	(0.2)	27.9	21.5
2020	(9.5)	41.7	0.1	31.6	63.9
2021	(0.2)	3.8	0.2	32.6	36.4
2022	(10.3)	20.4	8.7	38.6	57.4
2023	(7.1)	15.7	2.2	39.5	50.3
2024	(22.1)	12.6	2.5	39.6	32.6
2025	(28.0)	14.5	0.1	39.2	25.8
2026	(46.8)	9.8	2.3	34.3	(0.4)
2027	(48.8)	14.5	0.4	34.7	0.9
2028	(56.0)	20.5	(0.1)	33.3	(2.3)
2029	(47.9)	22.5	(0.2)	33.4	7.8
2030	(49.0)	27.4	(0.2)	33.4	11.6
2031	(45.6)	18.3	0.1	31.8	4.6
2032	(37.0)	(5.0)	0.2	29.8	(12.0)
2033	(29.5)	(25.0)	0.4	28.0	(26.2)
2034	(26.2)	(50.8)	0.6	26.2	(50.2)
2035	(36.8)	(58.1)	1.3	24.5	(69.2)

c) The total decrease in extraprovincial revenues of $39M in 2015/16 from MH14 to MH15 can be attributed to the following factors:

	2015/16
Price	(52)
Volume	(12)
Other	(26)
FX	51
Total	(39)

The $12M volume reduction in extraprovincial revenue in 2015/16 is due to a projected decrease in dependable deliveries with a corresponding increase mainly in off-peak deliveries. Although total deliveries do not differ greatly, deliveries to a lower priced market result in the $12M volume variance and are not related to the $52M price impact due to the change in forecast electricity export prices from MH14 to MH15.

d) The lines 28-30, page 25 of the 2016/17 Supplemental Filing should read as follows: "This decrease is largely offset by a projected weakening of the Canadian dollar ($451 million), higher forecast median inflows in 2017 compared to average, as well as a net reduction to Manitoba load ($74 million) resulting from lower forecast industrial load in 2020 and increased DSM energy and capacity savings 2019 and on."

e) Based on Attachment 16, the average unit revenue for Manitoba domestic energy is greater than the average unit revenue for total export sales for the twenty-year period to 2035, assuming the MH15 annual rate increases of 3.95% to 2028/29 and 2% per year thereafter.

Section:	Attachment 16 2015/16 & 2016/17 GRA Appendix 11.19	**Page No.:**	2 3
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Extraprovincial Revenues		
Issue:	Unit Export Revenues		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain how the unit revenues for Exports to Canada, Exports to the USA and Total Export Sales are each derived from the volume and revenue values reported in Attachment 16. (Note: Dividing total 2015/16 export revenues by total export volumes equals $42.47 (395,186/9,305) and not the reported value of $37.29.)

b) Please confirm whether unit revenue calculations for exports as set out in Appendix 11.19 from the previous GRA were performed on the same basis. If not, please provide values from IFF14 that are comparable to those in Attachment 16.

RATIONALE FOR QUESTION:

Clarify the basis on which the reported unit revenues from export sales are determined.

RESPONSE:

a) The calculation of average U.S. and total export unit revenues include net transmission charges as follows:

Total Export Sales to Canada:
$18,733/471 GW.h = $39.74/MW.h

Total Export Sales to USA:
($363,647+$3,900-$41,168)/8,785 GW.h = $37.15/MW.h

Total Export Sales:
($18,733+$363,647+$3,900-$41,168)/(471 GW.h + 8785 GW.h) = $37.29/MW.h

The schedule below amends Attachment 16 to provide notations on the average unit revenue/cost calculations in the far left column.

b) Confirmed.

DETAILED AVERAGE UNIT REVENUE/COST CALCULATION IFF15

	VOLUMES (GW.h)	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	2034/35
	Demand:																				
A	Manitoba Domestic Energy Sales	22593	23068	22971	22949	22705	23218	23289	23503	23710	23940	24176	24407	24634	24855	25080	25432	25908	26394	26926	27514
B	Domestic energy Losses	3088	3352	3373	3053	2996	3003	2893	2922	2952	2983	3016	3048	3083	3114	3146	3196	3259	3324	3395	3475
C	Firm & Opportunity Export Sales to Canada (excl. Lake St. Joseph)	471	263	581	603	618	888	993	889	883	870	902	901	915	906	902	923	914	909	903	901
D	**Lake St. Joseph**	**49**	**92**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**
E	Firm & Opportunity Export Sales to US	8785	6929	6183	6268	6855	9136	9986	9870	9622	9398	8835	8835	8389	8221	8031	7533	7010	6533	6109	5997
F	Net Transmission Losses	928	691	622	638	704	929	1011	987	963	935	894	892	855	835	813	774	718	668	622	586
	Total Demand Volumes:	**35914**	**34395**	**33820**	**33602**	**33970**	**37264**	**38263**	**38263**	**38220**	**38215**	**37914**	**38175**	**37966**	**38022**	**38063**	**37949**	**37899**	**37919**	**38046**	**38564**
	Supply:																				
G	MH Hydraulic Generation	34915	31858	31194	31098	31648	34555	35344	35308	35305	35201	35139	35360	35265	35258	35254	35322	35224	35222	35296	35314
H	MH Thermal Generation	58	63	370	348	289	154	158	158	149	158	158	159	135	137	139	122	118	114	112	107
I	Purchased Energy	941	2474	2256	2157	2033	2555	2762	2796	2767	2857	2618	2656	2567	2627	2670	2504	2558	2582	2638	3144
	Total Supply Volumes:	**35914**	**34395**	**33820**	**33602**	**33970**	**37264**	**38263**	**38263**	**38220**	**38215**	**37914**	**38175**	**37966**	**38022**	**38063**	**37949**	**37900**	**37919**	**38046**	**38564**

	REVENUE/COST (millions of dollars)	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	2034/35
	Total Manitoba Domestic Energy Sales:																				
J	Manitoba Domestic Energy Sales @ Approved Rates	1 517.178	1 555.835	1 552.633	1 552.228	1 541.920	1 566.389	1 570.022	1 582.776	1 595.823	1 610.406	1 625.643	1 640.589	1 655.004	1 669.083	1 683.412	1 705.869	1 734.283	1 763.345	1 795.408	1 831.203
K	Additional Domestic Revenue	-	61.455	125.080	191.300	258.442	334.786	410.833	493.050	579.785	671.805	769.162	871.698	979.465	1 092.743	1 157.835	1 230.864	1 311.079	1 394.977	1 484.657	1 581.166
	Manitoba Domestic Sales	**1 517.178**	**1 617.290**	**1 677.713**	**1 743.528**	**1 800.362**	**1 901.176**	**1 980.855**	**2 075.826**	**2 175.608**	**2 282.212**	**2 394.804**	**2 512.287**	**2 634.469**	**2 761.826**	**2 841.247**	**2 936.734**	**3 045.362**	**3 158.322**	**3 280.065**	**3 412.369**
	Extraprovincial Revenue:																				
L	Total Export Sales to Canada	18.733	17.032	34.607	37.530	41.104	74.620	85.355	76.668	77.698	78.366	82.994	84.839	88.340	89.978	92.021	96.310	98.551	101.052	103.495	105.824
M	Total Export Sales to USA	363.647	376.641	408.628	429.891	500.470	744.390	874.461	895.564	898.276	900.469	794.413	810.910	779.616	788.362	794.616	759.342	728.472	698.111	669.874	673.216
N	Other Non-Energy Related Revenues	8.907	8.281	2.268	2.299	2.327	2.355	2.402	2.449	2.497	2.546	2.597	2.648	2.700	2.753	2.807	2.863	2.919	2.977	3.035	3.095
O	Transmission Credits	3.900	4.047	3.909	3.892	3.872	3.850	3.931	4.013	4.097	4.183	4.271	4.361	4.453	4.546	4.642	4.739	4.839	4.940	5.044	5.150
	Extraprovincial Revenue	**395.186**	**406.001**	**449.413**	**473.611**	**547.773**	**825.215**	**966.148**	**978.694**	**982.568**	**985.566**	**884.275**	**902.757**	**875.108**	**885.639**	**894.086**	**863.253**	**834.781**	**807.080**	**781.448**	**787.285**
	Water Rentals & Assessments:																				
P	MH Water Rentals	116.712	106.493	104.267	103.947	105.786	115.505	118.141	118.022	118.009	117.662	117.455	118.193	117.875	117.853	117.840	118.069	117.739	117.733	117.980	118.039
Q	Assessments	6.500	6.745	6.515	6.486	6.453	6.416	6.551	6.689	6.829	6.972	7.119	7.268	7.421	7.577	7.736	7.898	8.064	8.234	8.406	8.583
R	Other Costs	2.485	2.309	2.334	2.358	2.381	2.404	2.428	7.233	7.505	7.695	7.489	7.633	7.843	8.090	8.402	8.745	9.037	9.370	9.652	9.693
	Water Rentals & Assessments:	**125.697**	**115.548**	**113.117**	**112.791**	**114.620**	**124.325**	**127.119**	**131.943**	**132.343**	**132.329**	**132.063**	**133.095**	**133.139**	**133.520**	**133.977**	**134.712**	**134.840**	**135.337**	**136.039**	**136.316**
	Fuel & Power Purchased:																				
S	MH Thermal Generation	2.821	2.932	25.061	24.114	20.903	12.978	13.993	14.596	14.289	15.778	16.478	17.374	15.359	16.400	17.398	16.213	16.252	16.536	16.965	16.851
T	Purchased Energy	71.738	101.251	117.704	116.340	114.325	135.130	148.387	153.262	155.650	163.065	153.321	159.145	158.550	166.064	173.024	166.338	173.905	180.805	189.933	225.390
U	Other Non-Energy related Costs	4.498	4.707	8.399	8.456	8.246	10.288	18.046	11.451	11.670	14.742	12.896	15.488	16.213	16.633	17.059	17.323	17.703	18.109	18.538	18.942
V	Transmission Charges	41.168	42.292	31.002	30.863	30.706	47.385	47.591	47.808	48.036	48.276	48.798	49.061	49.336	49.624	49.924	54.963	55.289	55.628	55.981	56.348
	Fuel & Power Purchased	**120.226**	**151.182**	**182.166**	**179.772**	**174.180**	**205.781**	**228.016**	**227.116**	**229.644**	**241.861**	**231.493**	**241.067**	**239.459**	**248.721**	**257.405**	**254.837**	**263.149**	**271.078**	**281.418**	**317.531**

AVERAGE UNIT REVENUE/COST ($/MW.h)	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	2034/35
Manitoba Domestic Energy Sales @ Approved Rates (J/A)	67.15	67.44	67.59	67.64	67.91	67.46	67.41	67.34	67.31	67.27	67.24	67.22	67.19	67.15	67.12	67.07	66.94	66.81	66.68	66.56
Additional Domestic Revenue (K/A)	-	2.66	5.45	8.34	11.38	14.42	17.64	20.98	24.45	28.06	31.82	35.72	39.76	43.96	46.17	48.40	50.61	52.85	55.14	57.47
Total Manitoba Domestic Energy Sales @ meter (J+K)/A	67.15	70.11	73.04	75.97	79.29	81.88	85.06	88.32	91.76	95.33	99.06	102.93	106.95	111.12	113.29	115.47	117.54	119.66	121.82	124.02
Total Export Sales to Canada (L/C)	39.74	64.68	59.60	62.25	66.49	84.02	85.99	86.22	87.98	90.07	91.96	94.12	96.58	99.30	102.02	104.39	107.85	111.21	114.63	117.40
Total Export Sales to USA (includes Net Trans Credits) (M+O-V)/E	37.15	48.84	61.71	64.28	69.09	76.72	83.19	86.29	88.79	91.13	84.88	86.72	87.58	90.41	93.30	94.13	96.73	99.10	101.32	103.72
Total Export Sales (L+M+O-V)/(C+E)	37.29	49.42	61.53	64.10	68.87	77.36	83.45	86.29	88.72	91.04	85.53	87.41	88.47	91.29	94.18	95.25	98.01	100.58	103.03	105.51
MH Hydraulic Generation (Water Rentals) (P/G)	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 (S/H)	48.82	46.65	67.65	69.37	72.26	84.32	88.82	92.33	96.01	99.98	104.35	109.14	114.00	119.55	125.08	132.40	138.26	144.59	150.86	157.49
Purchased Energy (Including Assessments) (T+Q)/I	83.16	43.66	55.06	56.94	59.41	55.40	56.10	57.20	58.72	59.52	61.29	62.65	64.65	66.10	67.70	69.59	71.13	73.21	75.19	74.43

Section:	4	Page No.:	25-26
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Other Revenues		
Issue:	Forecast Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) The Application indicates that, for IFF15, Other Revenues includes the amortization of customer contributions and billing surcharge recoveries as well as the recognition of BP III deferral account revenues – all of which are changes from IFF14. Please provide a schedule that for each of the years 2015/16 to 2024/25 shows the impact on Other Revenues of each of these changes.

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

Please see the attached table reflecting the net increase to other revenue resulting from amortization of customer contributions, billing surcharge recoveries, and BP III deferral account revenues.

($millions)	Amortization of Customer Contributions	Billing Surcharge Recoveries	BPIII Deferral Account Revenues	Other	Total
2016	9.8	3.4	-	1.9	15.1
2017	10.3	3.8	-	0.3	14.4
2018	10.6	3.8	-	(0.3)	14.0
2019	10.9	3.9	-	(0.3)	14.4
2020	11.2	3.9	86.8	(0.4)	101.6
2021	12.3	4.0	86.8	(0.4)	102.8
2022	12.7	4.1	86.8	(0.4)	103.2
2023	12.6	4.2	-	(0.4)	16.4
2024	12.4	4.3	-	(0.4)	16.3
2025	12.7	4.4	-	(0.4)	16.7

Section:	4 Attachment 37 2015/16 & 2016/17 GRA, Appendix 11.38	**Page No.:**	26 2 2
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Finance Expense		
Issue:	Forecast Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide schedules that set out the calculation of forecast Gross Interest Expense for both 2015/16 and 2016/17 pre IFF14 and IFF15. In doing so please indicate: i) the total amount of debt involved in each case, ii) the new issued issued in the "current" year, iii) the interest rates associated with pre-current year and current year debt; and iv) impact of foreign exchange.

b) Please provide schedules that set out the calculation of forecast Interest Allocated to Construction for both 2015/16 and 2016/17 per IFF14 and IFF15 that indicate both the total assets under construction and the interest rate used. Please also indicate the basis for the interest rates used in the calculation.

c) The Application states that capitalized interest is lower in 2015/16 and 2016/17 due to "later than planned capital expenditures on Bipole III and Keeyask".
   i. Please confirm that this statement is referring to delayed capital spending from 2014/15 (per page 50).
   ii. Please explain how delaying capital expenditures from 2014/15 to 2015/16 & 2016/17 (per page 50) leads to lower capitalized interest in 2015/16 & 2016/17.

d) Please explain how lower capitalized interest in 2015/16 & 2016/17 leads to an increase in Finance Expense.

e) If the response to part (d) is that interest rates used to calculate capitalized interest are lower in IFF15, please confirm that there would be also be a similar reduction in Gross Interest Expense such that the Interest Expense reported in the Operating Statement is relatively unchanged. If not, why not?

f) If the response to part (a) is that capital expenditures are lower, please explain why borrowings in the two years haven't been reduced to reflect the lower capital requirements.

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

a) As explained in the response to COALITION/MH-I-11a, given the integrated nature of the calculation of gross interest expense, it is impractical to decompose it into the component parts requested. However, to assist in the understanding of gross interest expense, the following schedules for 2015/16 and 2016/17 provide aggregated information according to major categories within the debt portfolio:

MANITOBA HYDRO **Gross Interest Expense ($ millions CAD)**	**IFF15** **2016**	**IFF14** **2016**	**Variance** **2016**
Canadian Fixed Rate Interest	455	452	4
Canadian Floating Rate Interest	37	46	(10)
US Fixed Rate Interest	156	135	20
US Floating Rate Interest	1	2	(0)
STD & Other	(11)	(8)	(2)
Gross Interest Expense	**638**	**627**	**12**

MANITOBA HYDRO **Gross Interest Expense ($ millions CAD)**	**IFF15** **2017**	**IFF14** **2017**	**Variance** **2017**
Canadian Fixed Rate Interest	542	551	(9)
Canadian Floating Rate Interest	34	71	(37)
US Fixed Rate Interest	159	135	24
US Floating Rate Interest	3	3	(1)
STD & Other	(3)	(4)	1
Gross Interest Expense	**735**	**756**	**(21)**

Please see Manitoba Hydro's response to PUB/MH I-31a for the further information on finance expense for these years.

b) Manitoba Hydro capitalizes interest on all domestic, major and new generation projects except certain short-term customer service projects with construction durations averaging approximately three months or less.

Interest during construction is calculated by applying the interest capitalization rate to the actual or forecasted month-end work in progress balance of each project, until such project becomes operational or a decision is made to abandon, cancel or indefinitely defer construction. Interest capitalized calculated by project is then aggregated to form total interest allocated to construction.

As it is impractical to provide the interest capitalization calculations by project for hundreds of projects, the following schedule demonstrates the calculation for the Bipole III Collector Lines project for both MH14 and MH15.

Please refer to PUB/MH-I-31b for the determination of interest capitalization rates.

BIPOLE III - COLLECTOR LINES (in thousands of dollars)

MH14

Date	Construction in Progress OB	Expenditures	Interest Capitalized	Plant In-Service	Construction in Progress CB	Nominal Monthly Interest Capitalized Rate
Apr-2015	87,521	3,816	408	-	91,744	0.47%
May-2015	91,744	7,703	442	-	99,889	0.48%
Jun-2015	99,889	2,476	466	-	102,830	0.47%
Jul-2015	102,830	1,015	495	-	104,341	0.48%
Aug-2015	104,341	1,610	502	-	106,454	0.48%
Sep-2015	106,454	2,228	496	-	109,178	0.47%
Oct-2015	109,178	15,494	526	-	125,198	0.48%
Nov-2015	125,198	2,835	583	-	128,617	0.47%
Dec-2015	128,617	3,696	619	-	132,932	0.48%
Jan-2016	132,932	9,238	640	-	142,810	0.48%
Feb-2016	142,810	3,886	643	-	147,339	0.45%
Mar-2016	147,339	14,989	709	28	163,009	0.48%
2016	**163,009**	**68,986**	**6,530**	**28**	**163,009**	
Apr-2016	163,009	2,898	789	-	166,696	0.48%
May-2016	166,696	2,168	833	-	169,697	0.50%
Jun-2016	169,697	2,291	821	-	172,809	0.48%
Jul-2016	172,809	1,774	864	-	175,447	0.50%
Aug-2016	175,447	1,592	877	-	177,917	0.50%
Sep-2016	177,917	1,722	861	-	180,500	0.48%
Oct-2016	180,500	2,112	902	9,307	174,206	0.50%
Nov-2016	174,206	1,603	843	3,312	173,340	0.48%
Dec-2016	173,340	4,337	866	25	178,518	0.50%
Jan-2017	178,518	2,692	892	19	182,083	0.50%
Feb-2017	182,083	2,794	822	16	185,683	0.45%
Mar-2017	185,683	15,441	928	17	202,036	0.50%
2017	**202,036**	**41,425**	**10,297**	**12,695**	**202,036**	

MH15

Date	Construction in Progress OB	Expenditures	Interest Capitalized	Plant In-Service	Construction in Progress CB	Nominal Monthly Interest Capitalized Rate
Apr-2015	63,728	4,235	293	-	68,256	0.46%
May-2015	68,256	2,451	324	0	71,030	0.48%
Jun-2015	71,030	2,661	326	-	74,017	0.46%
Jul-2015	74,017	1,699	351	-	76,067	0.48%
Aug-2015	76,067	2,224	361	-	78,653	0.48%
Sep-2015	78,653	7,479	361	-	86,493	0.46%
Oct-2015	86,493	5,628	411	-	92,532	0.48%
Nov-2015	92,532	4,644	425	-	97,600	0.46%
Dec-2015	97,600	10,270	464	-	108,334	0.48%
Jan-2016	108,334	25,672	515	-	134,521	0.48%
Feb-2016	134,521	4,017	598	-	139,136	0.45%
Mar-2016	139,136	5,147	661	474	144,470	0.48%
2016	**144,470**	**76,127**	**5,090**	**475**	**144,470**	
Apr-2016	144,470	6,125	639	-	151,234	0.44%
May-2016	151,234	3,436	691	-	155,361	0.46%
Jun-2016	155,361	2,235	687	-	158,282	0.44%
Jul-2016	158,282	2,016	723	-	161,021	0.46%
Aug-2016	161,021	1,994	736	-	163,751	0.46%
Sep-2016	163,751	3,308	724	-	167,783	0.44%
Oct-2016	167,783	2,800	766	2,244	169,105	0.46%
Nov-2016	169,105	3,324	748	7,798	165,379	0.44%
Dec-2016	165,379	4,048	756	21	170,163	0.46%
Jan-2017	170,163	5,485	778	17	176,410	0.46%
Feb-2017	176,410	5,884	729	16	183,007	0.41%
Mar-2017	183,007	6,674	837	18	190,500	0.46%
2017	**190,500**	**47,329**	**8,814**	**10,113**	**190,500**	

c) i. Confirmed.

ii. The nominal monthly interest capitalization rate is applied to the prior actual or forecasted month-end construction in progress balance. As a result, when the construction in progress balance of a project is lower due to delayed capital spending, the capitalized interest calculated is lower. Lower capitalization rates as a result of lower projected interest rates also contribute to the lower interest capitalization in 2016 and 2017.

The delayed spending is anticipated to be incurred in future periods, and as such, the interest will be capitalized at that time. It should be noted that a delay in spending and associated interest capitalization also results in lower compounded interest capitalization over the remaining project construction period.

Response to parts d), e) and f):

The Interest Allocated to Construction is the interest capitalized during the construction of a project, which is a reduction to finance expense and a charge to the capital project. The interest associated with a capital project is not included in net finance expense until the project is placed into service. During periods of intensive capital construction, the net finance expense, and hence the revenue requirement, is temporarily shielded from the full weight of the gross finance expense by the interest allocated to construction. As the level of capital investments subside and major project go in-service, the net finance expense closely approaches the total interest on short and long term debt.

In circumstances where interest rates become lower and new debt is issued at the lower interest rates, the weighted average interest rate (WAIR) associated with gross interest expense would be expected to decrease. However there would also be a reduction in the capitalized interest rate – thereby reducing the credited amount of interest allocated to construction and counterbalancing some of the impact of lower interest rates when deriving net finance expense.

The impacts to gross interest expense and interest allocated to construction are not necessarily in a one-to-one relationship as there are rate, volume and timing differences arising from evolving changes to the debt portfolio and capital expenditures.

On an actual basis, Manitoba Hydro considers the upcoming volume and timing of capital expenditures when planning its borrowing requirements. Borrowings are undertaken on a consolidated, portfolio basis and are not specifically identified to operating requirements or individual capital projects.

Section:	4 Attachment 4	**Page No.:**	26 13-14
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Finance Expense		
Issue:	Forecast Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Attachment 4 shows that capital spending on both Bipole III and Keeyask that was initially planned in IFF14 to occur in 2017/18 and 2018/19 is now scheduled to occur in 2015/16 and 2016/17. Please provide schedules that set out the cumulative capital spending as of the end of 2014/15, 2015/16, 2016/17, 2017/18, 2018/19 and 2019/20 for each of Bipole III and Keeyask consistent with CEF14 and CEF15. (Note: Please confirm in the response whether the values shown in CEF14 and CEF15 and used in the schedules include/exclude capitalized interest).

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

The following schedules outline the cumulative capital forecast by year for both Keeyask and Bipole III, consistent with CEF14 and CEF15. All schedules include capitalized interest.

KEEYASK & BIPOLE III
CEF 14 AND CEF 15
($millions)

CEF 14						CEF 14					
Project	**Total Plan**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**20/22**	**22/23**	**23/24**
Keeyask	**6,496.1**	**776.3**	**676.3**	**962.2**	**1,351.3**	**927.9**	**616.5**	**208.6**	**55.2**	**4.5**	**0.1**
Bipole III - Transmission Line	1,655.4	203.5	360.5	381.0	493.8	75.3	-	-	-	-	-
Bipole III - Converter Stations	2,675.1	221.1	580.8	828.7	507.7	195.1	18.4	4.5	-	-	-
Bipole III - Collector Lines	260.2	58.4	75.5	51.7	36.7	4.7	-	-	-	-	-
Bipole III - Community Develop Initiative	62.0	2.3	2.0	1.8	1.6	0.5	-	-	-	-	-
Bipole III	**4,652.6**	**485.2**	**1,018.7**	**1,263.3**	**1,039.8**	**275.4**	**18.4**	**4.5**	**-**	**-**	**-**

CEF 15		Actual					CEF 15				
Project	**Total Plan**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**20/22**	**22/23**	**23/24**
Keeyask	**6,496.1**	**704.4**	**818.7**	**1,112.0**	**1,226.2**	**835.8**	**552.6**	**193.0**	**140.2**	**0.2**	**0.0**
Bipole III - Transmission Line	1,655.4	128.3	447.1	495.0	359.8	86.5	-	-	-	-	-
Bipole III - Converter Stations	2,675.1	201.8	647.4	943.4	372.9	180.3	12.2	1.8	-	-	-
Bipole III - Collector Lines	260.2	35.1	81.2	56.1	44.1	11.3	-	-	-	-	-
Bipole III - Community Develop Initiative	62.0	2.1	2.1	1.8	1.5	0.6	-	-	-	-	-
Bipole III	**4,652.6**	**367.3**	**1,177.9**	**1,496.3**	**778.4**	**278.8**	**12.2**	**1.8**	**-**	**-**	**-**

Section:	Attachment 1 2015/16 & 2016/17 GRA Appendix 3.3	**Page No.:**	45 40
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Finance Expense		
Issue:	Forecast Comparisons		

PREAMBLE TO IR (IF ANY):

MH14 shows negative year-end cash balances for 2016 through to 2026 while MH15 shows positive cash balances (in excess of $500 M for several years) over the same period.

QUESTION:

a) Please explain why the borrowing in MH15 was not reduced so as to more closely align the forecast year-end cash balances with the values projected in MH14.

b) Does this higher level of borrowing increase the finance expense for the years 2016-2034?

c) What would be the impact on the finance expense for each of the years 2015/16 through 2034/35 if the borrowing levels in each year were set so as to result in year-end cash balances similar to those in MH14 for each year of the period?

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

a) Please see Manitoba Hydro's response to PUB/MH-I-30a.

Response to part b) and c):

It is anticipated that the enhanced prudential liquidity practice, that includes maintaining positive cash balances to mitigate liquidity risk, would reduce cumulative finance expense for the years 2016 – 2035.

The calculation of the financial implications of positive cash balances also cannot be adequately measured by performing a rudimentary analysis between the MH15 and a hypothetical scenario that seeks to return cash balances similar to those in MH14. That is because the scenarios without prudential liquidity would need to adjust the alternative scenarios with an upward interest rate adjustment for the anticipated rise in credit spreads. The financing flexibility provided by having long cash balances allows Manitoba Hydro to access funding during constructive tone when investor demand is present versus attempting to secure financing during periods of low investor appetite (which, from a supply and demand perspective, would likely require pricing concessions to investors in the form of wider credit spreads). The pricing concession to investors while securing one debt issue may also have an ongoing detrimental impact as it would likely establish new (higher) credit spread expectations for future debt issuance undertaken by Manitoba Hydro, as well as the Province of Manitoba for its own purposes. Although the future costs of foregoing prudential liquidity are uncertain and difficult to quantify, for illustrative purposes an additional liquidity premium may be 10 basis points.

The requested scenario to return year-end cash balances similar to those in MH14 for each year of the period is not a representative update to the Corporation's revenue requirement as it ignores the costs associated with a loss of financing flexibility. In order for the PUB to see a more representative outlook of potential implications to finance expense, Manitoba Hydro has also provided an additional MH14 scenario that shows the combined impact of eliminating forecasted positive cash balances with an upward interest rate adjustment for a projected liquidity premium of 10 basis points.

It should be noted that the impacts of liquidity risk cannot be fully quantified in attached scenarios. Eliminating prudential liquidity by excluding unencumbered cash balances would expose the Corporation to additional liquidity risk and/or result in large increases to financing costs and customer rates – hypothetical scenarios that the Corporation would not put into practice.

Please see the following schedule that illustrates the impact on net income for each of the years 2015/16 through 2034/35 with a comparison between MH15 and the two alternate scenarios. These alternate scenarios demonstrate that the elimination of prudential liquidity would be forecasted to have an adverse impact to net income decreasing by over $378 million to 2035, thereby increasing the need for higher rates. For the projected financial statements associated with these scenarios, please see Attachment 1 and 2 to this response.

COALITION/MH-I-21(c)
Net Income in $Millions

Fiscal Year	MH15*	MH15 reflecting COALITION 21c	Increase/ (Decrease)	MH15 reflecting COALITION 21c and Credit Spread +0.10%	Increase/ (Decrease) due to Credit Spread	Total Increase/ (Decrease)
2015/16	15	15	0	15	-	0
2016/17	29	42	13	40	(2)	11
2017/18	63	73	10	66	(6)	4
2018/19	(41)	(35)	6	(46)	(10)	(5)
2019/20	21	25	3	12	(13)	(10)
2020/21	(13)	(12)	1	(29)	(17)	(15)
2021/22	6	6	0	(11)	(17)	(16)
2022/23	(4)	(3)	1	(24)	(21)	(20)
2023/24	56	54	(2)	34	(21)	(23)
2024/25	129	129	0	107	(23)	(22)
2025/26	129	125	(4)	103	(22)	(26)
2026/27	232	227	(5)	204	(22)	(28)
2027/28	319	313	(6)	292	(21)	(27)
2028/29	439	433	(6)	411	(22)	(28)
2029/30	520	514	(6)	492	(22)	(28)
2030/31	592	586	(6)	564	(22)	(28)
2031/32	694	688	(7)	665	(23)	(29)
2032/33	769	762	(7)	740	(22)	(29)
2033/34	849	842	(7)	820	(22)	(29)
2034/35	946	939	(7)	917	(22)	(29)
20-Year Total to 2034/35			**(27)**		**(351)**	**(378)**

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH15 reflecting COALITION 21(c)
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES										
General Consumers										
at approved rates	1,517	1,556	1,553	1,552	1,542	1,566	1,570	1,583	1,596	1,610
additional*	0	61	125	191	258	335	411	493	580	672
BPIII Reserve Account	(54)	(67)	(69)	(21)	0	0	0	0	0	0
Extraprovincial	395	406	449	474	548	825	966	979	983	986
Other	29	28	28	29	116	118	119	32	32	33
	1,887	1,985	2,086	2,225	2,465	2,844	3,066	3,087	3,191	3,301
EXPENSES										
Operating and Administrative	542	552	557	571	585	601	607	619	631	644
Finance Expense	566	575	569	710	821	1,079	1,190	1,181	1,183	1,176
Depreciation and Amortization	410	426	450	535	589	690	742	762	781	800
Water Rentals and Assessments	126	116	113	113	115	124	127	132	132	132
Fuel and Power Purchased	120	151	182	180	174	206	228	227	230	242
Capital and Other Taxes	107	122	136	144	146	147	154	155	163	165
Other Expenses	2	2	2	2	2	2	2	3	3	3
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1,882	1,952	2,017	2,263	2,440	2,859	3,058	3,087	3,131	3,169
Non-controlling Interest	10	9	4	3	0	2	(1)	(3)	(5)	(3)
Net Income	15	42	73	(35)	25	(12)	6	(3)	54	129
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	15%	14%	14%	14%	13%	13%	12%	12%	12%	13%
Interest Coverage	1.02	1.05	1.07	0.97	1.02	0.99	1.01	1.00	1.05	1.11
EBITDA Interest Coverage	1.57	1.54	1.53	1.47	1.54	1.57	1.62	1.63	1.70	1.78
Capital Coverage	0.97	1.00	1.23	1.06	1.07	1.14	1.32	1.49	1.59	1.61

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH15 reflecting COALITION 21(c)
(In Millions of Dollars)

For the year ended March 31	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
REVENUES										
General Consumers										
at approved rates	1,626	1,641	1,655	1,669	1,683	1,706	1,734	1,763	1,795	1,831
additional*	769	872	979	1,093	1,158	1,231	1,311	1,395	1,485	1,581
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	884	903	875	886	894	863	835	807	781	787
Other	34	35	35	36	37	38	38	39	40	40
	3,313	3,450	3,545	3,684	3,772	3,838	3,919	4,004	4,101	4,240
EXPENSES										
Operating and Administrative	657	669	683	697	706	719	733	748	763	778
Finance Expense	1,170	1,162	1,140	1,119	1,093	1,061	1,000	969	936	900
Depreciation and Amortization	820	838	854	867	880	893	906	921	941	963
Water Rentals and Assessments	132	133	133	134	134	135	135	135	136	136
Fuel and Power Purchased	231	241	239	249	257	255	263	271	281	318
Capital and Other Taxes	166	167	168	169	171	172	173	175	177	179
Other Expenses	3	3	3	3	3	3	3	3	3	3
Corporate Allocation	8	8	8	8	5	3	3	3	3	3
	3,186	3,221	3,228	3,245	3,250	3,241	3,217	3,226	3,241	3,281
Non-controlling Interest	(1)	(2)	(4)	(5)	(8)	(11)	(14)	(16)	(19)	(20)
Net Income	125	227	313	433	514	586	688	762	842	939
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	68.78%	72.15%	75.60%	79.11%	82.69%	86.35%
Financial Ratios										
Equity	13%	14%	16%	17%	20%	22%	25%	28%	31%	35%
Interest Coverage	1.11	1.19	1.27	1.38	1.47	1.55	1.68	1.78	1.89	2.03
EBITDA Interest Coverage	1.80	1.91	2.01	2.15	2.26	2.38	2.58	2.72	2.89	3.08
Capital Coverage	1.61	1.78	1.90	2.02	2.21	2.19	2.34	2.44	2.53	2.45

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH15 reflecting COALITION 21(c)
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ASSETS										
Plant in Service	12,702	13,384	14,151	19,119	22,740	27,521	28,289	28,981	29,672	30,356
Accumulated Depreciation	(697)	(1,056)	(1,428)	(1,871)	(2,352)	(2,926)	(3,543)	(4,171)	(4,818)	(5,470)
Net Plant in Service	12,005	12,328	12,723	17,248	20,388	24,595	24,746	24,810	24,855	24,886
Construction in Progress	4,880	7,548	9,242	6,227	4,001	192	242	223	179	181
Current and Other Assets	1,819	2,061	2,393	2,507	2,537	2,648	1,865	2,016	2,280	2,468
Goodwill and Intangible Assets	237	287	396	563	675	952	916	881	846	813
Regulated Assets	277	298	753	787	811	831	850	839	817	796
	19,218	22,522	25,506	27,332	28,412	29,218	28,618	28,769	28,978	29,144
LIABILITIES AND EQUITY										
Long-Term Debt	13,887	16,986	18,899	21,329	21,829	22,608	22,563	22,857	22,837	22,525
Current and Other Liabilities	2,916	2,999	3,641	2,957	3,514	3,544	3,039	2,883	3,041	3,375
Provisions	53	52	52	52	53	53	53	54	54	54
Deferred Revenue	418	440	460	480	513	526	538	551	565	578
BPIII Reserve Account	103	170	239	260	174	87	-	-	-	-
Retained Earnings	2,612	2,654	2,727	2,692	2,716	2,704	2,710	2,707	2,762	2,891
Accumulated Other Comprehensive Income	(771)	(780)	(512)	(438)	(388)	(305)	(285)	(282)	(282)	(281)
	19,218	22,522	25,506	27,332	28,412	29,218	28,618	28,769	28,978	29,144

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH15 reflecting COALITION 21(c)
(In Millions of Dollars)

For the year ended March 31	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
ASSETS										
Plant in Service	31,081	31,760	32,474	33,199	33,909	34,645	35,389	36,152	36,984	37,813
Accumulated Depreciation	(6,141)	(6,818)	(7,513)	(8,216)	(8,936)	(9,677)	(10,405)	(11,151)	(11,930)	(12,671)
Net Plant in Service	24,941	24,942	24,961	24,983	24,973	24,968	24,984	25,001	25,054	25,142
Construction in Progress	146	172	162	152	140	153	141	138	143	259
Current and Other Assets	2,721	3,224	3,628	4,083	4,609	4,580	5,344	6,144	7,016	7,829
Goodwill and Intangible Assets	781	749	717	686	655	624	593	563	532	501
Regulated Assets	778	761	750	747	745	748	755	763	774	786
	29,366	29,847	30,218	30,652	31,122	31,074	31,817	32,608	33,519	34,517
LIABILITIES AND EQUITY										
Long-Term Debt	23,293	23,495	23,437	23,360	22,632	22,622	22,625	22,619	22,622	21,541
Current and Other Liabilities	2,690	2,728	2,831	2,897	3,567	2,929	2,968	2,989	3,039	4,165
Provisions	54	54	54	54	54	54	54	54	54	54
Deferred Revenue	592	607	619	632	646	659	673	687	702	717
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	3,017	3,243	3,556	3,989	4,503	5,089	5,777	6,540	7,382	8,320
Accumulated Other Comprehensive Income	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)
	29,366	29,847	30,218	30,652	31,122	31,074	31,817	32,608	33,519	34,517

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH15 reflecting COALITION 21(c)
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,974	2,041	2,145	2,235	2,367	2,745	2,966	3,074	3,178	3,288
Cash Paid to Suppliers and Employees	(855)	(898)	(943)	(963)	(975)	(1,032)	(1,063)	(1,086)	(1,109)	(1,134)
Interest Paid	(566)	(534)	(542)	(711)	(829)	(1,082)	(1,186)	(1,155)	(1,162)	(1,162)
Interest Received	9	3	11	19	22	19	17	2	2	5
	561	612	671	580	585	651	734	835	909	997
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,857	3,370	2,970	2,800	1,390	1,590	400	580	380	390
Sinking Fund Withdrawals	114	62	-	244	189	290	754	174	14	291
Retirement of Long-Term Debt	(361)	(320)	(330)	(984)	(329)	(865)	(757)	(450)	(290)	(412)
Other	82	(34)	(35)	(46)	(35)	(116)	(40)	(58)	(49)	(50)
	1,692	3,078	2,605	2,014	1,215	899	356	246	54	219
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2,614)	(3,437)	(3,085)	(2,211)	(1,645)	(1,149)	(829)	(730)	(694)	(745)
Sinking Fund Payment	(133)	(174)	(256)	(215)	(240)	(271)	(328)	(200)	(244)	(256)
Other	(21)	(21)	(21)	(21)	(21)	(32)	(31)	(32)	(32)	(32)
	(2,768)	(3,632)	(3,362)	(2,448)	(1,906)	(1,452)	(1,188)	(961)	(969)	(1,034)
Net Increase (Decrease) in Cash	(514)	57	(86)	147	(106)	97	(98)	119	(6)	183
Cash at Beginning of Year	482	(33)	24	(62)	85	(21)	76	(22)	97	91
Cash at End of Year	(33)	24	(62)	85	(21)	76	(22)	97	91	274

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH15 reflecting COALITION 21(c)
(In Millions of Dollars)

For the year ended March 31	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,300	3,436	3,531	3,670	3,758	3,823	3,904	3,989	4,086	4,225
Cash Paid to Suppliers and Employees	(1,136)	(1,159)	(1,171)	(1,195)	(1,214)	(1,225)	(1,248)	(1,272)	(1,299)	(1,351)
Interest Paid	(1,163)	(1,159)	(1,159)	(1,153)	(1,135)	(1,116)	(1,033)	(1,016)	(995)	(973)
Interest Received	6	14	30	42	50	61	42	54	66	79
	1,007	1,131	1,231	1,364	1,460	1,543	1,664	1,756	1,859	1,979
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	750	190	(10)	(10)	(30)	(10)	(10)	(30)	(30)	(50)
Sinking Fund Withdrawals	96	-	-	60	110	700	13	30	-	10
Retirement of Long-Term Debt	(715)	-	-	(60)	(80)	(700)	(13)	-	20	20
Other	(47)	(46)	(45)	(44)	(42)	(42)	(41)	(39)	(36)	(37)
	84	144	(55)	(54)	(42)	(52)	(51)	(39)	(46)	(57)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(756)	(782)	(787)	(810)	(788)	(836)	(849)	(874)	(941)	(1,108)
Sinking Fund Payment	(253)	(260)	(272)	(283)	(291)	(298)	(275)	(285)	(295)	(307)
Other	(32)	(33)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)
	(1,042)	(1,074)	(1,087)	(1,121)	(1,108)	(1,162)	(1,153)	(1,189)	(1,265)	(1,445)
Net Increase (Decrease) in Cash	50	201	89	189	310	328	461	528	548	478
Cash at Beginning of Year	274	324	525	614	803	1,113	1,441	1,902	2,430	2,978
Cash at End of Year	324	525	614	803	1,113	1,441	1,902	2,430	2,978	3,456

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH15 reflecting COALITION 21(c) and Credit Spread +0.10%
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
REVENUES										
General Consumers										
at approved rates	1,517	1,556	1,553	1,552	1,542	1,566	1,570	1,583	1,596	1,610
additional*	0	61	125	191	258	335	411	493	580	672
BPIII Reserve Account	(54)	(67)	(69)	(21)	0	0	0	0	0	0
Extraprovincial	395	406	449	474	548	825	966	979	983	986
Other	29	28	28	29	116	118	119	32	32	33
	1,887	1,985	2,086	2,225	2,465	2,844	3,066	3,087	3,191	3,301
EXPENSES										
Operating and Administrative	542	552	557	571	585	601	607	619	631	644
Finance Expense	566	577	575	720	834	1,096	1,207	1,202	1,204	1,199
Depreciation and Amortization	410	426	450	535	589	690	742	762	781	800
Water Rentals and Assessments	126	116	113	113	115	124	127	132	132	132
Fuel and Power Purchased	120	151	182	180	174	206	228	227	230	242
Capital and Other Taxes	107	122	136	144	146	147	154	155	163	164
Other Expenses	2	2	2	2	2	2	2	3	3	3
Corporate Allocation	8	8	8	8	8	8	8	8	8	8
	1,882	1,954	2,024	2,274	2,453	2,875	3,075	3,107	3,152	3,192
Non-controlling Interest	10	9	4	3	0	2	(1)	(3)	(5)	(3)
Net Income	15	40	66	(46)	12	(29)	(11)	(24)	34	107
Other Comprehensive Income	(51)	(9)	105	45	36	60	5	2	1	1
Comprehensive Income	(36)	31	171	(1)	48	32	(5)	(21)	34	107
* Additional General Consumers Revenue										
Percent Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%
Cumulative Percent Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%
Financial Ratios										
Equity	15%	14%	14%	14%	13%	13%	12%	12%	12%	12%
Interest Coverage	1.02	1.05	1.07	0.96	1.01	0.98	0.99	0.98	1.03	1.09
EBITDA Interest Coverage	1.57	1.54	1.52	1.46	1.53	1.55	1.60	1.61	1.67	1.75
Capital Coverage	0.97	1.00	1.22	1.04	1.05	1.11	1.29	1.45	1.55	1.57

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MH15 reflecting COALITION 21(c) and Credit Spread +0.10%
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
REVENUES										
General Consumers										
at approved rates	1,626	1,641	1,655	1,669	1,683	1,706	1,734	1,763	1,795	1,831
additional*	769	872	979	1,093	1,158	1,231	1,311	1,395	1,485	1,581
BPIII Reserve Account	0	0	0	0	0	0	0	0	0	0
Extraprovincial	884	903	875	886	894	863	835	807	781	787
Other	34	35	35	36	37	38	38	39	40	40
	3,313	3,450	3,545	3,684	3,772	3,838	3,919	4,004	4,101	4,240
EXPENSES										
Operating and Administrative	657	669	683	697	706	719	733	748	763	778
Finance Expense	1,193	1,185	1,161	1,141	1,115	1,083	1,022	992	958	922
Depreciation and Amortization	820	838	854	867	880	893	906	921	941	963
Water Rentals and Assessments	132	133	133	134	134	135	135	135	136	136
Fuel and Power Purchased	231	241	239	249	257	255	263	271	281	318
Capital and Other Taxes	165	167	168	169	170	171	173	174	176	179
Other Expenses	3	3	3	3	3	3	3	3	3	3
Corporate Allocation	8	8	8	8	5	3	3	3	3	3
	3,209	3,243	3,249	3,267	3,271	3,262	3,239	3,248	3,263	3,303
Non-controlling Interest	(1)	(2)	(4)	(6)	(8)	(11)	(14)	(16)	(19)	(20)
Net Income	103	204	292	411	492	564	665	740	820	917
Other Comprehensive Income	1	-	-	-	-	-	-	-	-	-
Comprehensive Income	104	204	292	411	492	564	665	740	820	917
* Additional General Consumers Revenue										
Percent Increase	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Cumulative Percent Increase	47.31%	53.13%	59.18%	65.47%	68.78%	72.15%	75.60%	79.11%	82.69%	86.35%
Financial Ratios										
Equity	13%	14%	15%	17%	19%	21%	24%	27%	30%	33%
Interest Coverage	1.09	1.17	1.25	1.36	1.44	1.52	1.65	1.74	1.85	1.98
EBITDA Interest Coverage	1.77	1.87	1.98	2.11	2.22	2.33	2.52	2.66	2.82	3.01
Capital Coverage	1.58	1.74	1.86	1.99	2.17	2.16	2.31	2.41	2.50	2.42

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH15 reflecting COALITION 21(c) and Credit Spread +0.10%
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
ASSETS										
Plant in Service	12,702	13,384	14,151	19,119	22,740	27,521	28,289	28,981	29,672	30,356
Accumulated Depreciation	(697)	(1,056)	(1,428)	(1,871)	(2,352)	(2,926)	(3,543)	(4,171)	(4,818)	(5,470)
Net Plant in Service	12,005	12,328	12,723	17,248	20,388	24,595	24,746	24,810	24,855	24,886
Construction in Progress	4,880	7,548	9,242	6,227	4,001	192	242	223	179	181
Current and Other Assets	1,819	2,060	2,393	2,492	2,539	2,605	1,983	2,136	2,375	2,340
Goodwill and Intangible Assets	237	287	396	563	675	952	916	881	846	813
Regulated Assets	277	298	753	787	811	831	850	839	817	796
	19,218	22,521	25,507	27,316	28,413	29,175	28,736	28,889	29,073	29,016
LIABILITIES AND EQUITY										
Long-Term Debt	13,887	16,986	18,899	21,329	21,829	22,608	22,763	23,057	23,037	22,525
Current and Other Liabilities	2,916	3,000	3,650	2,960	3,547	3,550	3,022	2,888	3,044	3,378
Provisions	53	52	52	52	53	53	53	54	54	54
Deferred Revenue	418	440	460	480	513	526	538	551	565	578
BPIII Reserve Account	103	170	239	260	174	87	-	-	-	-
Retained Earnings	2,612	2,652	2,718	2,673	2,684	2,656	2,645	2,621	2,655	2,761
Accumulated Other Comprehensive Income	(771)	(780)	(512)	(438)	(388)	(305)	(285)	(282)	(282)	(281)
	19,218	22,521	25,507	27,316	28,413	29,175	28,736	28,889	29,073	29,016

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MH15 reflecting COALITION 21(c) and Credit Spread +0.10%
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ASSETS										
Plant in Service	31,081	31,760	32,474	33,199	33,909	34,645	35,389	36,152	36,984	37,813
Accumulated Depreciation	(6,141)	(6,818)	(7,513)	(8,216)	(8,936)	(9,677)	(10,405)	(11,151)	(11,930)	(12,671)
Net Plant in Service	24,941	24,942	24,961	24,983	24,973	24,968	24,984	25,001	25,054	25,142
Construction in Progress	146	172	162	152	140	153	141	138	143	259
Current and Other Assets	2,574	3,054	3,437	3,871	4,375	4,324	5,066	5,843	6,693	7,484
Goodwill and Intangible Assets	781	749	717	686	655	624	593	563	532	501
Regulated Assets	778	761	750	747	745	748	755	763	774	786
	29,219	29,678	30,027	30,440	30,888	30,818	31,539	32,308	33,196	34,172
LIABILITIES AND EQUITY										
Long-Term Debt	23,293	23,495	23,437	23,360	22,632	22,622	22,625	22,619	22,622	21,541
Current and Other Liabilities	2,695	2,733	2,836	2,902	3,572	2,934	2,973	2,995	3,046	4,171
Provisions	54	54	54	54	54	54	54	54	54	54
Deferred Revenue	592	607	619	632	646	659	673	687	702	717
BPIII Reserve Account	-	-	-	-	-	-	-	-	-	-
Retained Earnings	2,864	3,068	3,360	3,771	4,264	4,828	5,493	6,233	7,053	7,969
Accumulated Other Comprehensive Income	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)
	29,219	29,678	30,027	30,440	30,888	30,818	31,539	32,308	33,196	34,172

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH15 reflecting COALITION 21(c) and Credit Spread +0.10%
(In Millions of Dollars)

For the year ended March 31	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
OPERATING ACTIVITIES										
Cash Receipts from Customers	1,974	2,041	2,145	2,235	2,367	2,745	2,966	3,074	3,178	3,288
Cash Paid to Suppliers and Employees	(855)	(898)	(943)	(963)	(974)	(1,032)	(1,063)	(1,086)	(1,109)	(1,134)
Interest Paid	(566)	(536)	(547)	(721)	(841)	(1,099)	(1,204)	(1,177)	(1,187)	(1,186)
Interest Received	9	3	11	19	22	19	17	2	2	5
	561	610	665	571	573	634	717	814	885	974
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	1,857	3,370	2,970	2,800	1,390	1,590	590	590	380	190
Sinking Fund Withdrawals	114	62	-	244	189	290	754	174	14	291
Retirement of Long-Term Debt	(361)	(320)	(330)	(984)	(329)	(865)	(757)	(450)	(290)	(412)
Other	82	(34)	(35)	(46)	(35)	(116)	(40)	(58)	(49)	(50)
	1,692	3,078	2,605	2,014	1,215	899	546	256	55	20
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(2,614)	(3,437)	(3,085)	(2,211)	(1,645)	(1,149)	(829)	(730)	(694)	(745)
Sinking Fund Payment	(133)	(174)	(256)	(215)	(241)	(271)	(328)	(200)	(244)	(257)
Other	(21)	(21)	(21)	(21)	(21)	(32)	(31)	(32)	(32)	(32)
	(2,768)	(3,632)	(3,362)	(2,448)	(1,906)	(1,452)	(1,188)	(962)	(970)	(1,035)
Net Increase (Decrease) in Cash	(514)	56	(92)	137	(118)	80	75	108	(31)	(41)
Cash at Beginning of Year	482	(33)	23	(69)	68	(49)	31	106	213	182
Cash at End of Year	(33)	23	(69)	68	(49)	31	106	213	182	142

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MH15 reflecting COALITION 21(c) and Credit Spread +0.10%
(In Millions of Dollars)

For the year ended March 31	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
OPERATING ACTIVITIES										
Cash Receipts from Customers	3,300	3,436	3,531	3,670	3,758	3,823	3,904	3,989	4,086	4,225
Cash Paid to Suppliers and Employees	(1,136)	(1,159)	(1,171)	(1,195)	(1,214)	(1,225)	(1,248)	(1,272)	(1,298)	(1,351)
Interest Paid	(1,184)	(1,183)	(1,182)	(1,176)	(1,158)	(1,140)	(1,057)	(1,040)	(1,019)	(998)
Interest Received	6	14	31	43	51	62	43	55	68	81
	987	1,109	1,209	1,342	1,437	1,520	1,641	1,733	1,836	1,957
FINANCING ACTIVITIES										
Proceeds from Long-Term Debt	750	190	(10)	(10)	(30)	(10)	(10)	(30)	(30)	(60)
Sinking Fund Withdrawals	97	-	-	60	110	700	13	30	-	10
Retirement of Long-Term Debt	(715)	-	-	(60)	(80)	(700)	(13)	-	20	20
Other	(47)	(46)	(45)	(44)	(42)	(42)	(41)	(39)	(36)	(37)
	85	144	(55)	(54)	(42)	(52)	(51)	(39)	(46)	(67)
INVESTING ACTIVITIES										
Property, Plant and Equipment, net of contributions	(756)	(782)	(787)	(810)	(788)	(836)	(849)	(874)	(941)	(1,108)
Sinking Fund Payment	(255)	(261)	(272)	(283)	(292)	(298)	(275)	(285)	(295)	(307)
Other	(32)	(33)	(28)	(28)	(29)	(29)	(29)	(29)	(30)	(30)
	(1,043)	(1,076)	(1,087)	(1,121)	(1,108)	(1,162)	(1,153)	(1,189)	(1,265)	(1,445)
Net Increase (Decrease) in Cash	29	177	67	167	287	306	437	505	525	445
Cash at Beginning of Year	142	171	348	415	582	870	1,175	1,613	2,118	2,643
Cash at End of Year	171	348	415	582	870	1,175	1,613	2,118	2,643	3,088

Section:	4	Page No.:	26
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Depreciation and Amortization Expense		
Issue:	Forecast Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule that for each of the years 2015/16 through 2024/25 compares depreciation and amortization expense as per MH 14 vs. MH 15 and separates out the annual impact of: i) the change in the treatment of amortization of customer contributions, ii) the change in the treatment of the recognition of BP III deferral account revenues, and iii) the change in DSM amortization.

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

The following schedule shows changes from MH14 to MH15 depreciation and amortization expense related to the reclassification of customer contribution amortization and Bipole III deferral account revenue recognition to other revenue, as well as the change in DSM amortization.

DEPRECIATION AND AMORTIZATION EXPENSE MH14 vs MH15
(in millions of dollars)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Depreciation and Amortization MH14	**401**	**422**	**445**	**521**	**524**	**613**	**667**	**736**	**752**	**767**
Remove Amortization of Electric Customer Contribution to Other Revenue	10	11	11	12	13	13	14	14	14	15
Remove Amortization of Bipole III Deferral Account to Other Revenue	-	-	-	-	54	54	54	-	-	-
Change in Amortization of Demand Side Management	(2)	(2)	(4)	(2)	(2)	(1)	1	5	7	9
Other changes in Electric Depreciation and Amortization	1	(6)	(3)	4	(0)	12	6	7	7	9
Depreciation and Amortization MH15	**410**	**426**	**450**	**535**	**589**	**690**	**742**	**762**	**781**	**800**

Section:	Attachment 16 2015/16 & 2016/17 GRA Appendix 11.19	**Page No.:**	2 3
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Fuel and Power Purchased		
Issue:	Forecast Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please explain how the unit cost for purchased energy in Attachment 16 is derived from the purchase volume and costs reported in Attachment 16.

b) Please confirm whether unit cost calculation for purchased energy as set out in Appendix 11.19 from the previous GRA was performed on the same basis.

c) For each of the years 2015/16 through 2024/25, please provide a breakdown of the variance in purchase power costs between IFF14 and IFF15 into the following components: i) volumes, ii) price, iii) foreign exchange rate, iv) transmission costs and iv) any other specific items as required.

d) To what extent are the lower transmission charges in each year associated with power purchases the result of the removal of intra-unit charges? Please provide the annual impacts for 2015/16 through 2024/25.

RATIONALE FOR QUESTION:

To understand change in forecast results

RESPONSE:

a) Please see Manitoba Hydro's response to COALITION/MH-I-17(a) for detailed calculations of the average unit cost for purchased energy.

b) Confirmed.

c) The following table splits out the MH15 vs. MH14 variance in Fuel & Power purchased into variances due to price, volume, the removal of intercompany transmission charges, foreign exchange and other. The majority of the variance in the 'Other' category is due to the elimination of a 200MW point to point transmission reservation which is partially offset by an increase in MISO Transmission tariffs as noted in the response to COALITION/MH-I-16(b).

Fuel & Power Purchased - Comparison MH15 vs MH14
(in millions of dollars)

	Variance due to:					
Fiscal Yr Ending	Price	Volume	Removal of Interco. Trans.	Other	FX	Total
2016	1	(10)	(12)	4	6	(10)
2017	(25)	(11)	(13)	(2)	11	(40)
2018	(7)	(2)	(13)	(8)	10	(20)
2019	(6)	(7)	(13)	(8)	7	(27)
2020	(5)	(10)	(13)	(9)	6	(31)
2021	(5)	(6)	(13)	(9)	6	(28)
2022	(6)	(5)	(13)	(18)	7	(35)
2023	(6)	(6)	(13)	(12)	7	(30)
2024	(10)	(9)	(14)	(12)	7	(37)
2025	(10)	(9)	(14)	(9)	7	(36)

d) The column "Removal of Interco Trans" in the table above contains the forecasted intercompany transmission charges that have been removed from both the Fuel & Power Purchased and the Extraprovincial Revenue line items on the Electric Operations operating statement. Note that on a net basis, there is no impact on the Electric Operations operating statement.

Section:	4 6 Attachment 8 Attachment 34 2015/16 & 2016/17 GRA, Appendix 5.5	**Page No.:**	24 48 1 15
Topic:	2015/16 through 2024/25 Forecast Results – Electric Operations		
Subtopic:	Depreciation and Amortization Expense		
Issue:	Forecast Comparisons		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to Figure 5.5.13 from Appendix 5.5 of the last GRA, please provide a similar table based on 2014/15 actuals and IFF15 forecast values for 2015/16 and 2016/17.

b) Attachment 8 indicates that for 2015/16 Manitoba Hydro is ahead of the schedule (relative to the plan underlying IFF14) in achieving its planned reductions in operational positions. How much of the $5.5 M year-to-date favourable variance in OM&A (per Attachment 8) is due to this?

c) Attachment 8 indicates that for 2015/16 Manitoba Hydro is ahead of the schedule (relative to the plan underlying IFF14) in achieving its planned reductions in operational positions. However, the forecast 2015/16 O&A cost is unchanged from IFF14 (Chapter 4, page 24) and, similarly, the ETFs are unchanged even though "straight time ETF is significantly lower than forecast" (Attachment 34). Please explain why the forecast ETFs and O&A cost for 2015/16 in IFF15 are not lower than that forecast in IFF14.

d) Given that the total ETFs are unchanged as between IFF14 and IFF15 and the capital spending in 2015/16 and 2016/17 is higher in CEF 15 than CEF14, why doesn't this lead to higher Labour and Benefits Charged to Capital in IFF15 along with higher Capitalized Overhead in IFF15 (vs. IFF14) such that Operating & Administrative expense reported on the Operating Statement would be less in IFF15 than IFF14 for these two years?

RATIONALE FOR QUESTION:

To understand the lack of change in forecast results for Operating & Administrative expense.

RESPONSE:

a) In MH14, Manitoba Hydro committed to limit the average annual growth of O&A to 1% for the years 2014/15 through to 2021/22, excluding the impacts of accounting changes and where major new generation and transmission come into service. The table below outlines the commitment through to the 2016/17 test year as well as the Corporation's achievement of a reduction of 1.4% in 2014/15. Manitoba Hydro continues to track favorably to forecast and expects to achieve the 1% commitment for 2015/16.

MANITOBA HYDRO
OPERATING AND ADMINISTRATIVE COSTS BY COST ELEMENT
(In thousands of $)

	2015/16 & 2016/17 GRA				Actual Results Achieved		
	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast	2012/13 Actual	2013/14 Actual	2014/15 Actual
Wages & Salaries	$ 480,511	$ 502,692	$ 525,103	$ 535,605	$ 466,165	$ 480,511	$ 493,346
Overtime	62,365	61,709	71,099	73,161	61,031	62,365	69,541
Employee Benefits	157,094	160,592	160,329	164,883	130,886	157,094	164,714
Sub-Total	699,970	724,993	756,531	773,649	658,082	699,970	727,601
Less: Labour & Benefits Charged to Capital	(234,510)	(256,588)	(283,568)	(289,984)	(215,491)	(234,510)	(257,457)
Labour & Benefits Charged to Operations*	465,460	468,405	472,963	483,664	442,591	465,460	470,144
Other Costs							
Employee Safety & Training	4,596	5,225	5,197	5,175	4,463	4,596	5,041
Travel Expenses	31,915	31,766	29,652	29,771	31,194	31,915	29,625
Motor Vehicle	29,670	29,682	29,700	29,699	29,516	29,670	30,452
Materials & Tools	27,939	26,700	26,100	26,090	24,827	27,939	24,723
Consulting & Professional Fees	14,657	14,349	13,430	13,237	10,817	14,657	16,154
Construction & Maintenance Services	16,944	19,449	18,665	18,580	16,392	16,944	17,969
Building & Property Services	30,022	28,603	28,650	27,297	26,781	30,022	30,427
Equipment Maintenance & Rentals	15,007	16,120	16,210	16,191	14,680	15,007	17,118
Consumer Services	5,277	5,323	5,323	5,323	5,050	5,277	5,189
Collection Costs	3,125	4,078	4,078	4,078	4,261	3,125	4,890
Customer & Public Relations	5,610	5,334	5,308	5,316	6,731	5,610	5,027
Sponsored Memberships	1,249	1,764	1,581	1,602	1,767	1,249	1,550
Office & Administration	14,724	15,722	15,709	15,717	13,874	14,724	14,243
Computer Services	678	985	1,069	1,019	849	678	967
Communication Systems	1,963	1,928	1,928	1,928	1,817	1,963	1,705
Research & Development Costs	2,195	2,747	2,747	2,747	3,372	2,195	2,534
Miscellaneous Expense	254	4	-	-	749	254	426
Contingency Planning	-	2,594	(414)	(231)	-	-	-
Operating Expense Recovery	(17,808)	(13,468)	(13,703)	(13,647)	(13,997)	(17,808)	(15,115)
Strategic Initiative Funding		870	3,640	6,317			-
Sub-Total	188,016	199,774	194,868	196,209	183,143	188,016	192,921
Less: Other Costs Charged to Capital	(31,503)	(33,329)	(34,859)	(35,556)	(29,327)	(31,503)	(33,442)
Other Costs Charged to Operations*	156,513	166,444	160,009	160,652	153,815	156,513	159,479
Total	**621,973**	**634,849**	**632,972**	**644,317**	**596,406**	**621,973**	**629,623**
Less:							
Labour & Expense Capitalized	(266,013)	(289,917)	(318,427)	(325,541)	(244,819)	(266,013)	(290,899)
Capitalized Overhead	(74,446)	(81,265)	(24,541)	(24,824)	(69,720)	(74,446)	(81,693)
Operating and Administration Charged to Centra	(66,810)	(67,829)	(66,691)	(67,818)	(63,735)	(66,810)	(67,458)
Electric OM&A, including Accounting Changes	**480,717**	**485,755**	**541,740**	**551,675**	**462,952**	**480,717**	**480,472**
Less: Forecast Accounting Changes	(91,155)	(93,858)	(145,644)	(151,345)	(78,345)	(91,155)	(96,188)
Electric OM&A, excluding Accounting Changes	**$ 389,562**	**$ 391,897**	**$ 396,096**	**$ 400,330**	**$ 384,607**	**$ 389,562**	**$ 384,285**
Year over Year % Change, including Accounting Changes		1.0%	11.5%	1.8%		3.8%	-0.1%
Year over Year % Change, excluding Accounting Changes		**0.6%**	1.1%	1.1%		1.3%	**-1.4%**

*Includes amounts capitalized through Overhead

b) Manitoba Hydro's response to PUB/MH-I-21a provides the estimated annual savings from Manitoba Hydro's commitment to reduce operational positions. The savings were partially offset by higher benefit expenditures due to the increase in current service costs for pensions as a result of a lower market driven discount rate.

c) Please see Manitoba Hydro's response to PUB/MH I-21d.

d) Please see Manitoba Hydro's response to COALITION/MH I-12a and COALITION/MH I-12b.

Section:	5 Attachment 1 2015/16 & 2016/17 GRA, Appendix 11.13	**Page No.:**	33 43 2
Topic:	Projected Financial Ratios		
Subtopic:	Debt/Equity Ratio		
Issue:	Calculation of Debt/Equity Ratio		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the calculation of the debt ratio (MH-Electric) based on IFF15 in a format similar to that used in the last GRA, Appendix 11.5.

b) Please indicate how, if at all, the BP III Reserve Account balance for each year enters into the calculation of the debt/equity ratio. If it does not affect the calculation, please indicate why this is appropriate.

c) Please indicate what is captured under "Regulated Assets" and how, if at all, the amount recorded enters into the calculation of the debt/equity ratio.

d) Please indicate what is captured under "Deferred Revenue" and how, if at all, the amount recorded enters into the calculation of the debt/equity ratio.

RATIONALE FOR QUESTION:

To understand the calculation of the debt/equity ratio.

RESPONSE:

a) A schedule with the calculation of the MH15 debt ratio in a format similar to Appendix 11.13 from the 2015/16 & 2016/17 GRA is provided below.

b) The BPIII Reserve Account is included with Deferred Revenue in the calculation of equity in the debt/equity ratio. Please see column G in the first schedule presented in part (a) above.

c) Regulated Assets and Regulated Liabilities represent deferred costs or credits that will be recovered or refunded in future rates as allowed under rate-regulated accounting. Please see notes 2 and 14 to the consolidated financial statements on pages 60 and 72 of the Manitoba Hydro-Electric Board 64th Annual Report for the year ended March 31, 2015 for further detail on Regulated Assets and Regulated Liabilities.

   Regulated Assets are not a component of the debt/equity ratio calculation.

d) Contributions in Aid of Construction or Unamortized Customer Contributions have been renamed Deferred Revenue under IFRS. Please see note 2(e) on page 62 of the Manitoba Hydro-Electric Board 64th Annual Report for the year ended March 31, 2015 for further detail on Deferred Revenue.

   Deferred Revenue is included as equity in the debt/equity ratio calculation.

Debt Ratio
Manitoba Hydro (Electric only)
($ millions)

	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**(J-K+L-M)**
				(A-B-C)			**(E-F)**							**(D+G+H+I+J-K+L-M)**
Fiscal Year Ended	Retained Earnings Consolidated	Retained Earnings Gas	Retained Earnings Subs	Retained Earnings	Deferred Revenue Consolidated	Deferred Revenue Gas	Deferred Revenue*	Accumulated Other Comprehensive Income	Non-Controlling Interest	Long-Term Debt	Sinking Fund Investment	Short-Term Debt	Short-Term Investments	Debt Ratio
2016				2 612			521	(771)	146	14 447	133	-	573	0.85
2017				2 641			610	(780)	182	17 526	247	-	617	0.86
2018				2 703			700	(512)	229	20 063	490	-	521	0.86
2019				2 663			740	(438)	258	21 838	454	-	659	0.87
2020				2 684			687	(388)	280	22 864	496	-	550	0.87
2021				2 671			613	(305)	289	23 126	459	-	248	0.87
2022				2 677			538	(285)	69	22 773	34	-	150	0.88
2023				2 673			551	(282)	72	23 107	60	-	468	0.88
2024				2 729			565	(282)	77	23 199	292	-	458	0.88
2025				2 858			578	(281)	80	22 980	258	-	440	0.87
2026				2 987			592	(280)	81	22 818	415	-	291	0.87
2027				3 219			607	(280)	83	23 010	675	-	497	0.86
2028				3 538			619	(280)	87	23 002	947	-	592	0.84
2029				3 977			632	(280)	92	22 935	1 170	-	787	0.83
2030				4 497			646	(280)	101	22 827	1 352	-	1 103	0.80
2031				5 089			659	(280)	107	22 120	950	-	1 437	0.78
2032				5 784			673	(280)	102	22 100	1 212	-	1 905	0.75
2033				6 553			687	(280)	100	22 074	1 467	-	2 439	0.72
2034				7 402			702	(280)	98	22 067	1 761	-	2 994	0.69
2035				8 348			717	(280)	95	22 041	2 058	-	3 479	0.65

*Includes BPIII Reserve Account

Calculation of Long-Term Debt for input into Debt:Equity Ratio

	A	B	C (A-B)	D	E	F (D-E)	G (C+F)
Fiscal Year Ended	MHEB Long-Term Debt	Gas Long-Term Debt	Long-Term Debt	MHEB Current Portion of Long-Term Debt	Gas Current Portion of Long-Term Debt	Current Portion of Long-Term Debt	Long-Term Debt
2016	14 487	360	14 127	320	0	320	14 447
2017	17 586	390	17 196	330	0	330	17 526
2018	19 499	420	19 079	984	0	984	20 063
2019	21 929	420	21 509	329	0	329	21 838
2020	22 429	430	21 999	865	0	865	22 864
2021	22 808	440	22 368	757	0	757	23 126
2022	22 763	440	22 323	470	20	450	22 773
2023	23 257	440	22 817	300	10	290	23 107
2024	23 237	450	22 787	412	0	412	23 199
2025	22 725	460	22 265	750	35	715	22 980
2026	23 293	475	22 818	0	0	0	22 818
2027	23 495	485	23 010	0	0	0	23 010
2028	23 437	495	22 942	60	0	60	23 002
2029	23 360	505	22 855	110	30	80	22 935
2030	22 632	505	22 127	700	0	700	22 827
2031	22 622	515	22 107	13	0	13	22 120
2032	22 625	525	22 100	30	30	0	22 100
2033	22 619	525	22 094	0	20	(20)	22 074
2034	22 622	535	22 087	10	30	(20)	22 067
2035	20 941	555	20 386	1 675	20	1 655	22 041

Section:	5	**Page No.:**	32-25
Topic:	Projected Financial Ratios		
Subtopic:			
Issue:	Comparison of Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide revised versions of Figures 16, 17 and 18 that also include the values/ratios from the financial projection provided in the NFAT proceeding for the development plan adopted by the PUB.

RATIONALE FOR QUESTION:

To compare currently projected results with those from recent forecasts considered by the PUB.

RESPONSE:

In the PUB's report on the Needs For and Alternatives To (NFAT) Review of Manitoba Hydro's Preferred Development Plan – Final Report (June 20, 2014), the Panel did not adopt a specific development plan but rather recommended the following related to specific resource options:

- that the Government of Manitoba authorize Manitoba Hydro to proceed with the construction of the Keeyask Project to achieve a 2019 in-service date and the 750 MW U.S. Transmission Interconnection Project for a 2020 in-service date;
- that the Government of Manitoba not approve the construction of the Conawapa Project and the North-South Transmission Upgrade Project; and
- that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.

The NFAT development plan which most closely reflects the PUB recommendations above is Development Plan (5) Keeyask 2019/ Gas/ 750 MW with DSM Level 2 (denoted as "NFAT" in the graphs below). Please note that Development Plan (5) was prepared under the following assumptions:

- 2013 Manitoba Electricity Load Forecast
- 2013 Electricity Export Price Forecast
- 2013 Projected Escalation, Interest and Exchange Rates
- Three (3) rate setting methodologies which were presented during the NFAT hearings:
  - Main Submission Methodology:
    - Beginning in fiscal year ending 2015, even annual rate increases for 18 years to achieve the targeted debt:equity ratio (75:25) by the 2032
    - From 2032 forward, rates are adjusted annually to maintain an Earnings before Interest and Taxes (EBIT) interest coverage ratio at 1.20
  - Method #1
    - Beginning in fiscal year ending 2015, 3.95% rate increases per year until the interest coverage ratio reaches 1.20
    - From that point forward, rates are adjusted annually to maintain the interest coverage ratio at 1.20
  - Method #2
    - Since not all scenarios prove to be financially acceptable maintaining 3.95% annual rate increases – specifically in the first 10 years of the forecast - an alternative approach to rate setting was prepared
    - Rates above 3.95% were assumed over a five year period between fiscal year 2018 to 2022 to improve the projected financial performance of the Corporation. The following metrics were considered when setting rates:
      - Net income/loss and the impacts on retained earnings during the first 10 years of the forecast
      - Interest coverage ratio
      - Debt ratio and the attainment of the 75:25 debt:equity target
    - From 2023 on, 3.95% rate increases per year until the interest coverage ratio reaches 1.20 and then rates are adjusted annually to maintain the interest coverage ratio at 1.20

The figures below provide the figures for the requested alternate scenarios:

Figure 16 Projected Electric Retained Earnings

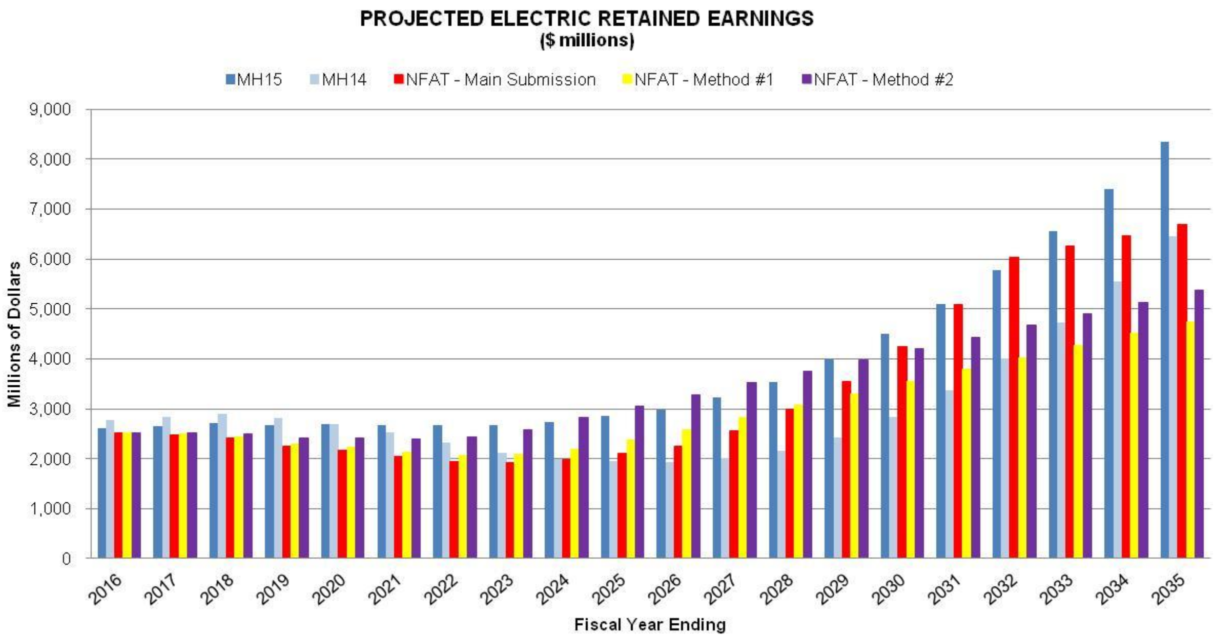


Figure 17 Projected Electric Equity Ratio

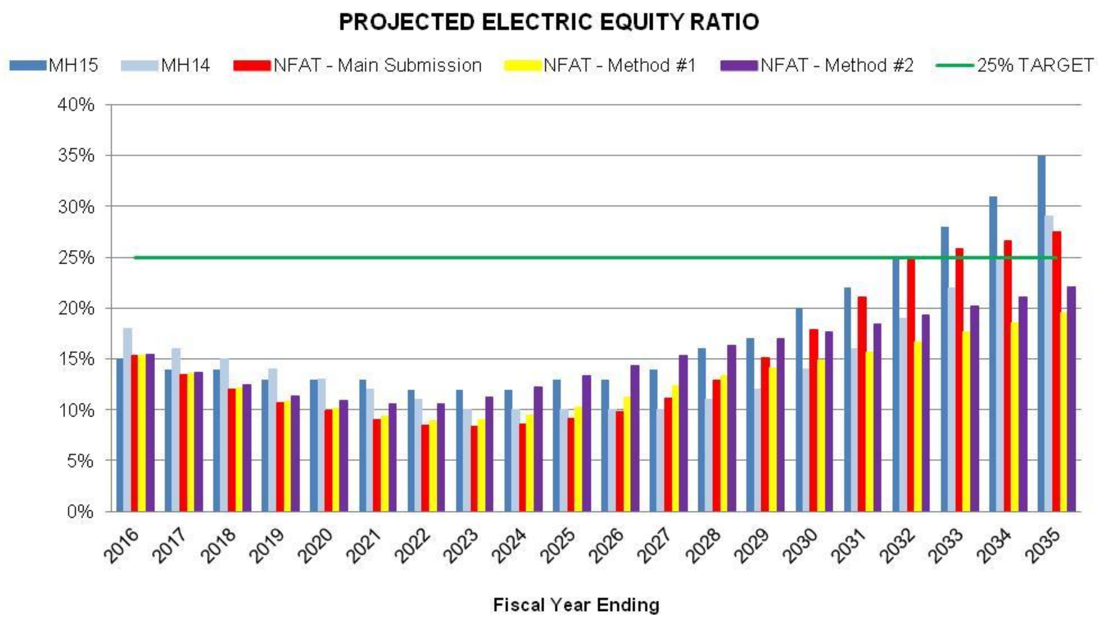
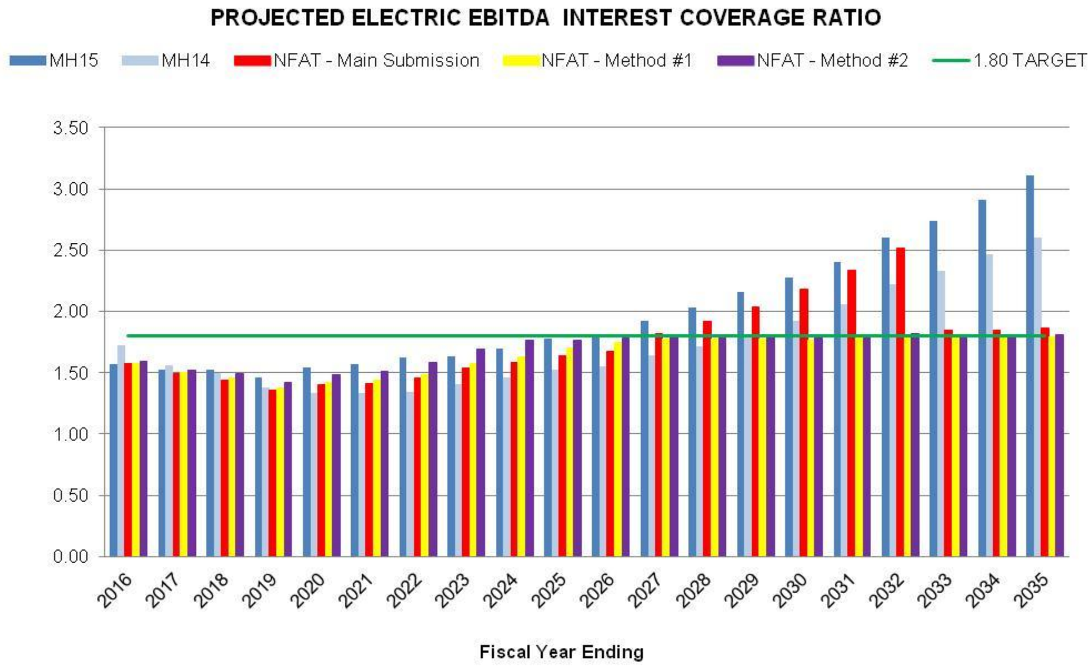


Figure 18 Projected Electric EBITDA Interest Coverage Ratio



Section:	5 Attachment 1	**Page No.:**	38 30
Topic:	Rate Increase Sensitivity Analysis		
Subtopic:	Cost of Drought		
Issue:	Basis for Calculation		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Does the estimated $1.9 B cost of a 5-year drought include the impact on finance expense?

RATIONALE FOR QUESTION:

To clarify the basis on which the estimated cost of a 5-year drought was calculated.

RESPONSE:

Confirmed. The $1.9B cost of a 5-year drought includes an increase in finance expense of $241 million compared to MH15.

Section:	Attachment 28	**Page No.:**	1-2 and 5-10
Topic:	Rate Increase Sensitivity Analysis		
Subtopic:	Impact of Board Directives		
Issue:	Basis for Calculation- Scenario 1		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For purposes of Scenario 1, please confirm whether the treatment of the difference between the CGAAP Average Service Life (ASL) method of depreciation and the Equal Life Group (ELG) method of depreciation was as follows:

   i. The difference in each year was recorded on the Balance Sheet as a regulatory asset.

   ii. The balance in the account each year was amortized to net income at a rate of 2.98%

   iii. The amortization was included in the Operating Statement under Depreciation and Amortization.

   If not confirmed, please clarify what the treatment was.

b) Please provide a schedule that separately indicates the specific impacts (versus MH15) that the use of ASL has on the Operating Statement annually for 2015/16 through 2024/25 under Scenario 1.

c) Please confirm that both methods of depreciation (ASL and ELG) eventually result in assets being fully depreciated. If not confirmed, please explain why.

d) Please explain why it is necessary to amortize the difference between the ASL method of depreciation and the ELG method of depreciation.

   i. Won't the ASL method eventually result in the assets being fully depreciated?

   ii. Why couldn't the difference be accrued in a deferral account and not amortized – with the view that overtime the deferral account would "self-clear"?

e) Please provide a schedule that sets out, for the years 2015/16 through 2033/34, the balances that would accrue if the difference between ASL and ELG were accrued in a deferral account but <u>not</u> amortized.

RATIONALE FOR QUESTION:

To understand the reported results for Scenario 1.

RESPONSE:

a) The treatment of the difference between the CGAAP Average Service Life (ASL) method of depreciation and the IFRS Equal Life Group (ELG) method of depreciation was as follows:
   i. Confirmed, the difference in each year was recorded on the Balance Sheet as a Regulated Asset.
   ii. Confirmed, the balance in the account each year was amortized to net income at a rate of 2.98% (approximately 34 years) as specified as an assumption in the question for Financial Information MFR 1**.**
   iii. Confirmed, the amortization was included in the Operating Statement under Depreciation and Amortization.

   Please note that Scenario 1 is not compliant with IFRS 14 *Regulatory Deferral Accounts*, which requires the impact of changes arising from rate regulation to be presented in the Net Movement in Regulatory Deferral line.

b) The table below provides the differences between MH15 and the results under Scenario 1 with respect to the change in depreciation methods (CGAAP ASL vs. IFRS compliant ELG).

	Impacts of Use of ASL Method *in millions*				
Fiscal Year Ended	Operating & Administrative	Finance Expense	Depreciation and Amortization	Capital and Other Taxes	Increase / (Decrease) to Net Income
2016	-	0	(30)	0	30
2017	-	0	(31)	0	30
2018	-	0	(31)	1	30
2019	-	0	(35)	1	34
2020	-	0	(37)	1	36
2021	-	0	(43)	1	42
2022	-	0	(45)	1	44
2023	-	1	(45)	2	42
2024	-	0	(44)	2	42
2025	-	0	(44)	2	41

c) Manitoba Hydro confirms that both methods of depreciation (CGAAP ASL and IFRS ELG) eventually results in an individual asset being fully depreciated.

d) Although the difference in depreciation between the IFRS ELG and CGAAP ASL methods will reverse over time for individual assets, the actual timing of this reversal for the pool of Manitoba Hydro's assets is not evident in the 20 year MH15 forecast. As per MH15, by fiscal 2035 Manitoba Hydro will have more than doubled its existing PP&E asset cost. Considering that much of the assets projected to be added over the next 20 years have service lives in the range of 25 – 100+ years, the timing of the reversal between the IFRS ELG and CGAAP ASL differences will extend beyond the 20 year forecast period.

As per the *IFRS14 Regulatory Deferral Accounts* interim standard, if a regulatory deferral account is not amortized into customer rates over a reasonable time period, there is a significant risk that the deferral account would not qualify for recognition on the financial statements. As per the standard:

B3 For the purposes of this Standard, a regulatory deferral account balance is defined as the balance of any expense (or income) account that would not be recognised as an *asset or a liability in accordance with other Standards, but that qualifies for deferral because it is included, or is expected to be included, by the rate regulator in establishing the rate(s) that can be charged to customers. Some items of expense (income) may be outside the regulated rate(s) because, for example, the amounts are not expected to be accepted by the rate regulator or because they are not within the scope of the rate regulation. Consequently, such an item is recognised as income or expense as incurred,…,*

In order to qualify for deferral there needs to be an expectation that the regulator will include the deferral amounts in rates. This expectation is key for financial statement recognition as the users (e.g The Province of Manitoba, lenders, PUB) of the statements require the ability to assess how future cash flows of the utility will be impacted by such accounts.

e) Please see the table below for the cumulative increase in the balance of the account if the deferral is not amortized.

(in $ millions)

Fiscal Period	ELG Less ASL Annual Difference	Cumulative Difference
2016	31	31
2017	33	64
2018	34	99
2019	39	138
2020	43	181
2021	50	231
2022	54	285
2023	55	340
2024	56	396
2025	57	453
2026	59	512
2027	60	572
2028	62	634
2029	63	697
2030	64	761
2031	66	827
2032	67	894
2033	69	963
2034	70	1,033
2035	72	1,105

Section:	Attachment 28	**Page No.:**	1-2 and 5-10
Topic:	Rate Increase Sensitivity Analysis		
Subtopic:	Impact of Board Directives		
Issue:	Basis for Calculation- Scenario 1		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For purposes of Scenario 1, please confirm that the treatment of the $20 M of OH deemed ineligible for capitalization under IFRS was as follows:
   i. The $20 M was recorded on the Balance Sheet as a regulatory asset.
   ii. The $20 M from each year recorded as amortized over 20 years to net income.
   iii. The amortization was included in the Operating Statement under Depreciation and Amortization.

   If not confirmed, please clarify what the treatment was.

b) Please provide a schedule that separately indicates the specific impacts (versus MH15) that the continued capitalization of the $20 M in OM&A has on the Operating Statement annually for 2015/16 through 2024/25 under Scenario 1.

c) With respect to the Projected Operating Statement for Scenario 1, please explain the purpose of the Other Comprehensive Income line and how the values for each year are determined.

RATIONALE FOR QUESTION:

To understand the reported results for Scenario 1.

RESPONSE:

a) The treatment of the $20 million of overhead deemed ineligible for capitalization under IFRS in Scenario 1 was as follows:

   i. Confirmed; the $20 million was recorded on the Balance Sheet as a Regulated Asset.

   ii. Not confirmed; the $20 million from each year was assumed to be amortized over 30 years to net income as requested in the question in Financial Information MFR 1 from the 2016/17 Supplemental Filing.

   iii. Confirmed; the amortization was included in the Operating Statement under Depreciation and Amortization.

   Please note that Scenario 1 is not compliant with IFRS 14 *Regulatory Deferral Accounts*, which requires the impact of changes arising from rate regulation to be presented in the Net Movement in Regulatory Deferral line.

b) The table below specifies the difference between MH15 and the $20 million in overhead ineligible for capitalization.

	Impacts of Deferral of $20 M in OH Deemed Ineligible for Capitalization *in millions*				
Fiscal Year Ended	Operating and Administrative	Finance Expense	Depreciation and Amortization	Capital and Other Taxes	Increase / (Decrease) to Net Income
2016	(20)	-	1	0	19
2017	(20)	0	2	0	18
2018	(20)	0	2	0	17
2019	(20)	0	3	0	17
2020	(20)	0	4	1	16
2021	(20)	0	4	1	15
2022	(20)	0	5	1	14
2023	(20)	1	6	1	13
2024	(20)	0	6	1	13
2025	(20)	0	7	1	12

c) Per note 2(i) on page 63 of the Manitoba Hydro-Electric Board 64th Annual Report for the year ended March 31, 2015, Other Comprehensive Income (OCI) is calculated as follows:

"Comprehensive income consists of net income and other comprehensive income (OCI). OCI includes unrealized gains and losses arising from changes in the fair value of available-for-sale assets and changes in the foreign exchange rate for U.S. denominated long-term debt and interest payments in effective cash flow hedging relationships. Such amounts are recorded in accumulated OCI (AOCI) until the criteria for recognition in net income are met."

The balances in OCI for Scenario 1 are unchanged from the balances in MH15. This line item was included in the presentation for Scenario 1 to facilitate a comparison to Scenario 2 which assumes that the amortization of regulatory differences for the $20 million of overhead and difference in depreciation between the CGAAP ASL and IFRS ELG method is recorded in OCI.

Section:	Attachment 28	**Page No.:**	2 and 11-16
Topic:	Rate Increase Sensitivity Analysis		
Subtopic:	Impact of Board Directives		
Issue:	Basis for Calculation- Scenario 2		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With respect to Scenario 2, is the amortization of the regulatory accounts recorded in the Operating Statement under the line – "Other Comprehensive Income"?

b) What accounts for the differences seen in the annual Depreciation and Amortization amounts reported on the Operating Statement between Scenarios 1 and 2?

c) What accounts for the differences seen in the annual Other Comprehensive Income amounts reported on the Operating Statement between Scenarios 1 and 2?

d) What account for the differences see in the annual Accumulated Other Comprehensive Income amounts reported on the Balance Sheet between Scenarios 1 and 2?

RATIONALE FOR QUESTION:

To understand the results shown for the various scenarios.

RESPONSE:

a) Confirmed, the assumed amortization of the $20 million of ineligible overhead annually and the difference in depreciation between the CGAAP Average Service Life (ASL) and IFRS Equal Life Group (ELG) methods of depreciation is included in Other Comprehensive Income (OCI) in the Operating Statement for the purposes of Scenario 2.

b) The difference in the annual Depreciation and Amortization amounts between Scenario 1 and Scenario 2 is due to the transfer of both the assumed amortization of the $20 million of ineligible overhead annually and the difference between the CGAAP ASL and IFRS ELG methods of depreciation from Depreciation and Amortization in Scenario 1 to OCI in Scenario 2. The table below shows the details of the change in Depreciation and Amortization between Scenario 1 and Scenario 2.

	DEPRECIATION AND AMORTIZATION *in millions*			
	A	B	C	D = A + B + C
Fiscal Year Ended	Scenario 1	Less: Transfer Amortization of Deferred $20 M in OH to OCI	Less: Transfer Amortization of ASL versus ELG Difference to OCI	Scenario 2
2016	381	(1)	(1)	379
2017	397	(2)	(2)	393
2018	421	(2)	(3)	416
2019	503	(3)	(4)	495
2020	555	(4)	(6)	546
2021	652	(4)	(7)	640
2022	701	(5)	(9)	688
2023	723	(6)	(10)	707
2024	743	(6)	(12)	725
2025	763	(7)	(14)	743
2026	784	(8)	(15)	761
2027	803	(8)	(17)	777
2028	821	(9)	(19)	793
2029	834	(10)	(21)	804
2030	848	(10)	(23)	815
2031	863	(11)	(25)	827
2032	877	(12)	(27)	839
2033	893	(12)	(29)	852
2034	915	(13)	(31)	871
2035	938	(14)	(33)	891

c) The difference in the annual OCI amounts between Scenario 1 and Scenario 2 is due to the transfer of both the assumed amortization of the $20 million of ineligible overhead annually and the difference between the CGAAP ASL and the IFRS ELG methods of depreciation from Depreciation and Amortization in Scenario 1 to OCI in Scenario 2. The table below shows the details of the change in OCI between Scenario 1 and Scenario 2.

	OTHER COMPREHENSIVE INCOME *in millions*			
	A	B	C	D = A + B + C
Fiscal Year Ended	Scenario 1	Add: Transfer Amortization of Deferred $20 M in OH to OCI	Add: Transfer Amortization of ASL versus ELG Difference to OCI	Scenario 2
2016	(51)	(1)	(1)	(53)
2017	(9)	(2)	(2)	(13)
2018	105	(2)	(3)	99
2019	45	(3)	(4)	37
2020	36	(4)	(6)	27
2021	60	(4)	(7)	49
2022	5	(5)	(9)	(8)
2023	2	(6)	(10)	(13)
2024	1	(6)	(12)	(17)
2025	1	(7)	(14)	(20)
2026	1	(8)	(15)	(22)
2027	-	(8)	(17)	(25)
2028	-	(9)	(19)	(28)
2029	-	(10)	(21)	(30)
2030	-	(10)	(23)	(33)
2031	-	(11)	(25)	(36)
2032	-	(12)	(27)	(38)
2033	-	(12)	(29)	(41)
2034	-	(13)	(31)	(44)
2035	-	(14)	(33)	(46)

d) The difference in Accumulated Other Comprehensive Income (AOCI) on the Balance Sheet between Scenario 1 and Scenario 2 is the cumulative transfer from Depreciation and Amortization in Scenario 1 to OCI in Scenario 2 of the assumed amortization of the $20 million of ineligible overhead annually and the difference between the CGAAP ASL and IFRS ELG methods of depreciation. The table below shows the details of the change in AOCI between Scenario 1 and Scenario 2.

	ACCUMULATED OTHER COMPREHENSIVE INCOME *in millions*					
	A	B	C	D = A + B + C	E	F = D + E
Fiscal Year Ended	Opening Cumulative Transfers of Amortization to OCI	Add: Transfer Amortization of Deferred $20 M in OH to OCI	Add: Transfer Amortization of ASL versus ELG Difference to OCI	Closing Cumulative Transfers of Amortization to OCI	Scenario 1	Scenario 2
2016	-	(1)	(1)	(2)	(771)	(773)
2017	(2)	(2)	(2)	(6)	(780)	(786)
2018	(6)	(2)	(3)	(12)	(512)	(524)
2019	(12)	(3)	(4)	(19)	(438)	(458)
2020	(19)	(4)	(6)	(29)	(388)	(416)
2021	(29)	(4)	(7)	(40)	(305)	(345)
2022	(40)	(5)	(9)	(54)	(285)	(338)
2023	(54)	(6)	(10)	(69)	(282)	(352)
2024	(69)	(6)	(12)	(88)	(282)	(369)
2025	(88)	(7)	(14)	(108)	(281)	(389)
2026	(108)	(8)	(15)	(131)	(280)	(411)
2027	(131)	(8)	(17)	(156)	(280)	(436)
2028	(156)	(9)	(19)	(184)	(280)	(464)
2029	(184)	(10)	(21)	(215)	(280)	(495)
2030	(215)	(10)	(23)	(248)	(280)	(527)
2031	(248)	(11)	(25)	(283)	(280)	(563)
2032	(283)	(12)	(27)	(321)	(280)	(601)
2033	(321)	(12)	(29)	(362)	(280)	(642)
2034	(362)	(13)	(31)	(406)	(280)	(686)
2035	(406)	(14)	(33)	(452)	(280)	(732)

Section:	7 Attachment 1 Attachment 45	Page No.:	50 6 5 & 6
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba-Saskatchewan Transmission Project		
Issue:	Rationale for Project		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please confirm that without the firm sale contract to Saskatchewan, the power would be sold to the US market.

RATIONALE FOR QUESTION:

This is a new project included in CEF15

RESPONSE:

Not confirmed.

In addition to the US market, Manitoba Hydro has transmission access to Ontario (IESO market), Saskatchewan, and the Alberta (AESO market). Manitoba Hydro sells surplus energy and capacity to customers in these jurisdiction or markets when transmission is available and the economics are favourable.

Section:	7 Attachment 1 Attachment 45	**Page No.:**	50 6 5 & 6
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba-Saskatchewan Transmission Project		
Issue:	Rationale for Project		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Attachment 45 states "the expenditures on the Manitoba-Saskatchewan Transmission Project are justified by the 20-year 100 MW sale to SaskPower". Please provide the business case that demonstrates this.

RATIONALE FOR QUESTION:

This is a new project included in CEF15

RESPONSE:

The sale involves signing long term firm sale agreements at premium prices from surplus dependable energy and accredited capacity made available as a result of the development of Keeyask and the new 500 kV interconnection.

This sale agreement will provide the following benefits:

a) a fixed revenue stream over 20 years that reduces export revenue at risk;
b) incremental value when all revenues, capital and operating costs are included;
c) a permanent expansion of MH's export market access into Saskatchewan and,
d) increased Manitoba energy security and reliability associated with a firm power sale.

Section:	7 Attachment 1 Attachment 45	**Page No.:**	50 6 5 & 6
Topic:	Capital Expenditure Forecast		
Subtopic:	Manitoba-Saskatchewan Transmission Project		
Issue:	Rationale for Project		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Please provide forecast of the annual impact on Manitoba Hydro's operating statement of the new 230 kV Manitoba-Saskatchewan Transmission project in terms of: i) increased export revenues (over revenues that would otherwise be received in the US export market), ii) increased depreciation, finance and OM&A expense and iii) overall impact on net income.

RATIONALE FOR QUESTION:

This is a new project included in CEF15

RESPONSE:

Manitoba Hydro is unable to provide the information requested for the proposed sale to Saskatchewan as it is commercially sensitive and therefore confidential. Manitoba Hydro can confirm that there are net benefits to the anticipated sale to SaskPower even when the costs of the 230 kV Manitoba-Saskatchewan Transmission project are considered.

Section:	7 Attachment 4 Attachment 24 2015/16 & 2016/17 GRA, Appendix 4.1	**Page No.:**	50 17 47 17
Topic:	Capital Expenditure Forecast		
Subtopic:	DSM		
Issue:	Comparison of Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) The “Previously Approved” DSM spending amounts included in CEF15 do not match the Forecast amounts in CEF14. Please explain why and what the basis is for the Previously Approved amounts shown in CEF15.

RATIONALE FOR QUESTION:

To understand the change in forecast DSM spending as presented in IFF15.

RESPONSE:

The “Previously Approved” amounted shown for DSM in CEF15 removes the 2015 fiscal year from the CEF14 Revised Forecast and adds the 2035 fiscal year to the CEF15 comparison. The aggregate of the latter ten years of the forecast also shifts one year later in the CEF15 comparison.

The following tables detail the annual CEF14 DSM expenditures reflected in CEF15 Previously Approved and CEF14 Revised Forecast.

Demand Side Management CEF14

2015	51.8	Removed for Comparison to CEF15
2016	59.2	Unchanged
2017	76.6	Unchanged
2018	83.9	Unchanged
2019	93.7	Unchanged
2020	78.2	
2021	72.5	
2022	60.8	
2023	50.0	
2024	49.6	
2025	47.5	
2026	48.3	
2027	47.2	
2028	47.2	
2029	48.3	
2030	50.2	
2031	52.2	
2032	54.4	
2033	56.6	
2034	58.9	821.9 Years 2020-2034
2035	60.0	803.7 Years 2021-2035

Demand Side Management CEF15

	Total	2016	2017	2018	2019	2020	2021-35
Previously Approved	NA	$ 59.2	$ 76.6	$ 83.9	$ 93.7	$ 78.2	$ 803.7
Increase (Decrease)	-	3.1	(18.6)	14.9	0.9	11.9	581.7
Revised Forecast	NA	$ 62.3	$ 58.0	$ 98.8	$ 94.6	$ 90.2	$1 385.4

Demand Side Management CEF14

	Total	2015	2016	2017	2018	2019	2020-34
Previously Approved	NA	$ 25.3	$ 24.6	$ 23.9	$ 22.6	$ 21.7	$ 266.9
Increase (Decrease)		26.5	34.6	52.7	61.3	72.0	555.0
Revised Forecast	NA	$ 51.8	$ 59.2	$ 76.6	$ 83.9	$ 93.7	$ 821.9

Section:	7 Attachment 4 Attachment 24 2015/16 & 2016/17 GRA, Appendix 4.1	**Page No.:**	50 17 47 17
Topic:	Capital Expenditure Forecast		
Subtopic:	DSM		
Issue:	Comparison of Forecasts		

PREAMBLE TO IR (IF ANY):

QUESTION:

b) The forecast DSM spending in CEF15 does not match the annual electric DSM budget as set out in Attachment 24 (page 47). Please reconcile.

RATIONALE FOR QUESTION:

To understand the change in forecast DSM spending as presented in IFF15.

RESPONSE:

The table below reconciles the DSM budget in Attachment 24 and CEF 15.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	DSM Budget in Attachment 24	*Less: DSM Operating Budget*	*Interest Income & Administration Costs on Loans*	*Interest Expense on Loans*	*Escalation Difference*	*DSM Budget (Adjusted)*	**CEF15**
2015/16	**$ 61.6**	$ (1.1)	$ (0.2)	$ 0.4	$ 1.5	$ 62.3	**$ 62.3**
2016/17	**$ 57.5**	$ (1.1)	$ (0.2)	$ 0.4	$ 1.4	$ 58.0	**$ 58.0**
2017/18	**$ 97.3**	$ (1.1)	$ (0.2)	$ 0.4	$ 2.4	$ 98.8	**$ 98.8**
2018/19	**$ 93.3**	$ (1.2)	$ (0.3)	$ 0.4	$ 2.3	$ 94.6	**$ 94.6**
2019/20	**$ 89.0**	$ (1.2)	$ (0.3)	$ 0.4	$ 2.2	$ 90.2	**$ 90.2**
2020/21	**$ 91.3**	$ (1.2)	$ (0.3)	$ 0.4	$ 2.3	$ 92.4	**$ 92.4**
2021/22	**$ 95.4**	$ (1.2)	$ (0.4)	$ 0.5	$ 2.4	$ 96.6	**$ 96.6**
2022/23	**$ 71.9**	$ (1.2)	$ (0.4)	$ 0.5	$ 1.8	$ 72.4	**$ 72.4**
2023/24	**$ 67.0**	$ (1.3)	$ (0.4)	$ 0.5	$ 1.6	$ 67.4	**$ 67.4**
2024/25	**$ 70.5**	$ (1.3)	$ (0.5)	$ 0.5	$ 1.7	$ 70.9	**$ 70.9**
2025/26	**$ 76.0**	$ (1.3)	$ (0.5)	$ 0.5	$ 1.9	$ 76.5	**$ 76.5**
2026/27	**$ 81.2**	$ (1.3)	$ (0.5)	$ 0.5	$ 2.0	$ 81.9	**$ 81.9**
2027/28	**$ 87.6**	$ (1.4)	$ (0.5)	$ 0.5	$ 2.2	$ 88.3	**$ 88.3**
2028/29	**$ 94.2**	$ (1.4)	$ (0.5)	$ 0.5	$ 2.3	$ 95.1	**$ 95.1**
2029/30	**$ 96.1**	$ (1.4)	$ (0.7)	$ 0.6	$ 2.4	$ 96.9	**$ 96.9**

Column (a) outlines the total electric DSM budget in Attachment 24.

The DSM budget in Attachment 24 includes both capital and operating budgets associated with electric DSM efforts, while CEF 15 includes only capital budgets. Column (b) removes the operating budget.

CEF 15 includes the administration costs, interest income and interest expenses associated with DSM loans while Attachment 24 does not include these items. Column (c) outlines the interest income and administration costs and column (d) outlines the interest expense.

The DSM budget in Attachment 24 assumes an annual escalation whereas the CEF assumes a monthly escalation. Column (e) outlines the difference in escalation from these two methodologies.

Column (f) shows the DSM budget after making the adjustments in columns (b) to (e) which is the same as the CEF 15 budget shown in column (g).

Section:	Attachment 4 Attachment 24	**Page No.:**	17 53
Topic:	Capital Expenditure Forecast		
Subtopic:	DSM		
Issue:	Cost Effectiveness		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) CEF15 (page 17) claims that the electric DSM plan is cost effective as a resource option, while Attachment 24 (page 53) provides the specific DSM Metrics. Is this assessment of cost effectiveness based on the export price forecast used in IFF15? If not, what is the basis for the evaluation and how different are the forecast exports prices?

RATIONALE FOR QUESTION:

Confirm business case for the planned DSM spending levels.

RESPONSE:

The 2015 Power Smart Plan was assessed using marginal values that incorporated the 2014/15 export price forecast as this was the most current export price forecast available at the time the 2015 Power Smart Plan was developed. When the 2015 Power Smart Plan was assessed as part of the 2015 Resource Planning Assumptions and Analysis, the 2015/16 export price forecast was used. The 2015 Power Smart Plan remained cost effective using these updated assumptions. The 2015/16 export price forecast was also used in the IFF 15.

As indicated in page ii of IFF15, the key changes in the 2014/15 and 2015/16 export price forecasts are as follows:

- The 2015/16 export price forecast has electricity export prices that are on average approximately 20% lower in 2015/16 and 34% lower in 2016/17 compared to those in the 2014/15 export price forecast.

- The 2015/16 export price forecast has long term electricity export prices for 2017/18 to 2034/35 that are 3% to 7% lower on average than to those in the 2014/15 export price forecast due to continued lower natural gas and coal prices.

In addition to generation marginal costs, which are developed using the long term export price forecast as a key input, the marginal costs used in the evaluation of programs also include marginal transmission and distribution cost components.

Section:	Attachment 1 Attachment 16 2015/16 & 2016/17 GRA, Appendix 11.19 2015/16 & 2016/17 GRA, Appendix 3.3	**Page No.:**	6 2 3 6
Topic:	Power Resources		
Subtopic:	Hydraulic Generation		
Issue:	Comparison of Forecast		

PREAMBLE TO IR (IF ANY):

According to IFF14 and IFF15, the hydraulic volumes for the second forecast year in each uses "the median of 80 years of historic flows and initial reservoir and lake level elevations".

QUESTION:

a) Please explain why the hydraulic volumes shown for the second year of the IFF15 forecast (i.e. 31,858 GWh for 2016/17 per Attachment 16) are significantly lower than the volumes shown for the second year of the IFF14 forecast (i.e., 34,418 GWh for 2015/16 per Appendix 11.19).

RATIONALE FOR QUESTION:

To understand the change in the forecast.

RESPONSE:

The hydraulic generation forecast in the second year of an IFF reflects Manitoba Hydro's forecast of carry forward storage from the first year; and the assumption that inflows into reservoirs will be median. As carry forward storage varies from year to year, there can be differences in second year hydraulic generation when comparing IFFs.

In the second year of IFF15 the hydraulic volume forecast is lower than the second year of IFF14 due to less carry forward storage from the preceding year. Year 1 of IFF14 (fiscal year

2014/15) experienced extreme flood volumes on the Winnipeg River (record high) and Saskatchewan River. All this water could not be released from storage over the winter of 2014/15 which resulted in a large carry forward storage at the beginning of fiscal 2015/16. This carry forward storage is more than is expected for the beginning of 2016/17 which explains the decrease from IFF14 to IFF15.