

## Manitoba Hydro Book of Documents #1

TAB 1	NFAT CAC/MPA 1-002
TAB 2	NFAT PUB/MPA 1-027
TAB 3	NFAT PUB/MPA 1-030
TAB 4	Bonneville Power Administration Annual Report 2016, as referenced in errata to MPA Report, Exhibit <a href="#">CC-17-1</a>
TAB 5	Long Island Power Authority 2016 Annual Report, as referenced in errata to MPA Report, Exhibit <a href="#">CC-17-1</a>
TAB 6	Santee Cooper 2016 Annual Report, as referenced in errata to MPA Report, Exhibit <a href="#">CC-17-1</a>
TAB 7	Page 1 to 10 of Appendix 4.4 - MHEB DBRS Credit Rating Report November 25, 2016
TAB 8	Pages 1 to 38 from MPA-3 NFAT Report Jan 2014
TAB 9	MIPUG-MH I-8a-k
TAB 10	TVA, For Generations to Come, presentation dated June 2, 2017
TAB 11	Moody's Investor Service - <i>US Public Power Electric Utilities With Generation Ownership Exposure</i> (pages 1, 14-16)



**TAB 1**

1 **CAC/MPA 1-002**

2 **REFERENCE:**

3 MPA Report, page 18 (lines 1-2)

4 **PREAMBLE:**

5

6 **QUESTION:**

7 Please provide any documentation that supports the statement that the 25% target level of  
8 equity has either been agreed to or is required by the shareholder.

9 **RESPONSE:**

10 MPA has received no documentation which explicitly states that the Government of Manitoba  
11 has agreed to the 75:25 debt to equity target for Manitoba Hydro.

12 However, the Board of Directors of Manitoba Hydro adopted this policy in 1995, as noted in our  
13 Report. The Board of Directors is appointed by the Government of Manitoba, and since 1995  
14 the Government has had ample opportunity to raise objections to this policy if it were  
15 considered to be a concern. Moreover, the target ratio is referred to by credit rating agencies  
16 when they consider whether Manitoba Hydro is financially self-supporting, and given the  
17 importance of this view of Manitoba Hydro, if the ratio were of concern then the Government  
18 would likely have suggested a change. Finally, the Government interacts with Manitoba Hydro  
19 with respect to debt arrangements. If there were any concern with respect to financial targets  
20 as important as the debt ratio of the corporation, then it must be presumed that the issue  
21 would have been addressed at some point over the past 18 years.

22

TAB 2

1 **PUB/MPA 1-027(a)**

2 **REFERENCE:**

3 MPA Report Page 61 Line 18

4 **PREAMBLE:**

5 MPA states :

6 In a "normal situation, Manitoba Hydro's guidelines target not only an interest coverage ratio  
7 of at least 1.2, but also coverage of typical capital spending requirements from internally  
8 generated funds. If the company were not able to meet this objective during a one or two-year  
9 drought, it would be unlikely the credit rating agencies would reassess their position on the  
10 ability of Manitoba Hydro to be self-sustaining. However if drought conditions continued, and  
11 rates were not allowed to rise sufficiently to meet these interest and capital costs, than the  
12 shortfall in meeting them would become a focus for attention.

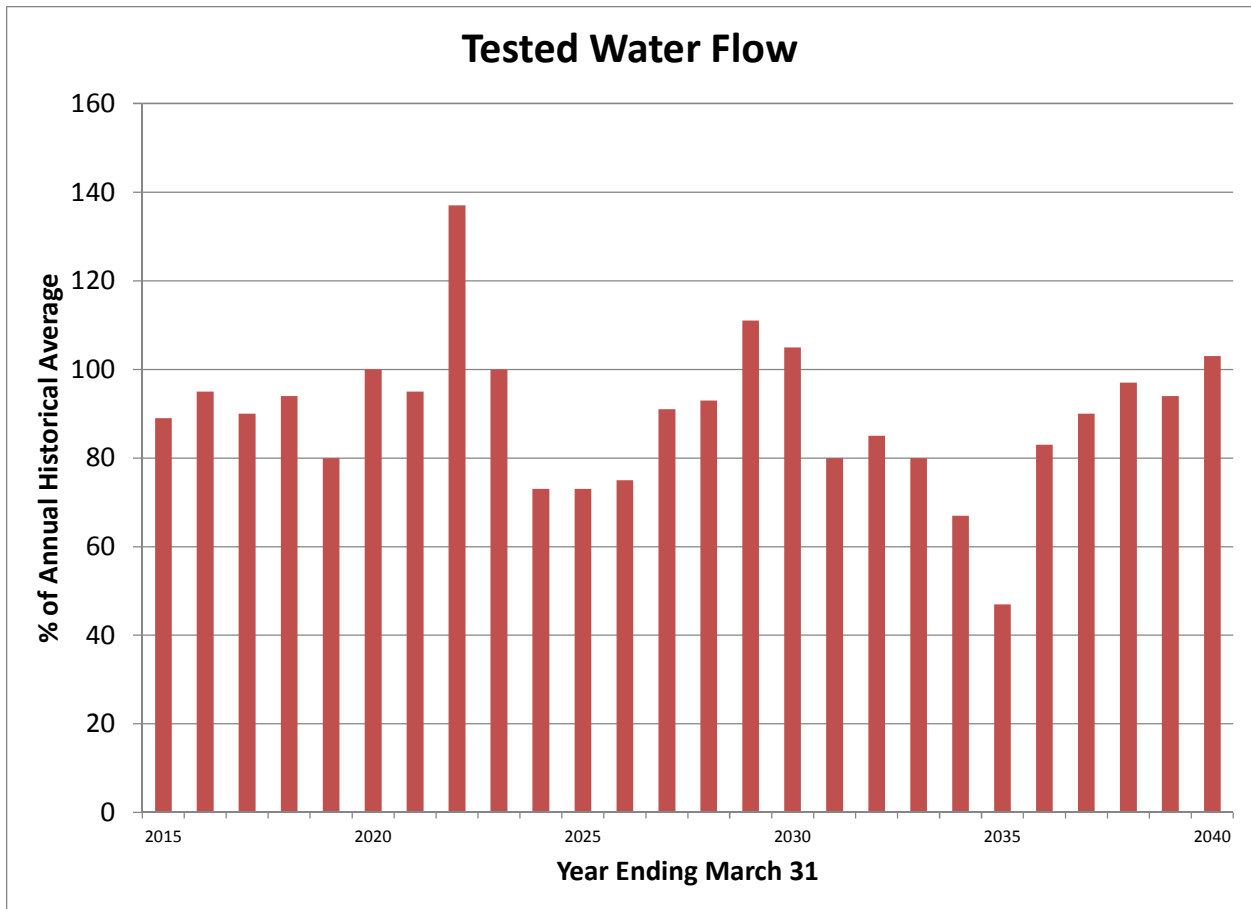
13 **QUESTION:**

14 Please provide a comparative analysis of the impact on net income and financial ratios of a  
15 severe 5 year and severe 7 year drought in the 2030's. Please provide the analysis on the basis  
16 of the indicated annual rate increase, and where the indicated rate increase is capped at no  
17 more than twice the rate of inflation.

18 **RESPONSE:**

19 MPA applied a challenging hydrology scenario to all five of the Plans reviewed in our Report. A  
20 graph of the hydrology scenario is provided on the next page.

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Several features from this graph should be noted:

- Not many of the years have water flow above 100% of the historical average;
- There is a fairly significant drought in the fiscal years ending 2024 to 2026 where water flow is below 80% of historical average in each year
- There is a very serious drought in the years ending 2031 to 2035, with “recovery” really only coming in the late 2030s
- For the first twenty years depicted, the average water flow is the “flip side” of the experience of the past twenty years in Manitoba (i.e., in the past twenty years, average waterflow in Manitoba has been about 110% of historical average, whereas in the first twenty years depicted in the graph, average water flow is about 90% of historical average)

- 1       • This hydrology scenario actually happened historically (according to the data provided  
2           by Manitoba Hydro)

3 Plans 1 (All-Gas), 4, 6, 12 and 14 (the Preferred Development Plan) were all subjected to this  
4 hydrology scenario. Reference economics, Reference capital costs and Reference 2012 demand  
5 were used for all model runs. In all cases, rate increases on Manitoba ratepayers were capped  
6 at no more than two times the rate of inflation. Given the 1.9% rate of inflation in the  
7 Reference economics scenario, this means that domestic rates were not allowed to rise by  
8 more than 3.8% per year.

9 All Plans were tested under all three energy price scenarios, High/Reference/Low.

10 Despite how severe any period of drought might be, the model runs assume that Manitoba  
11 Hydro fulfils all of its contractual obligations, and never declares “adverse water” or “force  
12 majeure” under any of its firm export contracts. This means that in some cases Manitoba Hydro  
13 may be importing power in order to export it again, or that it is meeting its export obligations  
14 by burning natural gas. In reality, if Manitoba were faced with a serious and prolonged drought,  
15 it might make economic sense to declare “adverse water” or “force majeure”, however doing  
16 so might have longer term consequences with respect to signing future firm export contracts.

17 The tables on the following pages present the information listed below for all five Plans. Each  
18 page presents three tables, one each for High energy prices, Reference energy prices, and Low  
19 energy prices. (In addition, we have provided a separate, attached file with one table per page,  
20 so the tables are larger and easier to read. Placing three tables on a page together facilitates  
21 comparisons between the impacts of High/Reference/Low energy prices at a glance).

22 Tables are provided showing the path over 26 years of the following financial indicators:

- 23       • Net Income
- 24       • Equity Ratio (Manitoba Hydro has a 25% equity ratio target)
- 25       • Interest Coverage Ratio (Manitoba Hydro has a 1.2x interest coverage ratio target)



- 1 • Operating Cash Flow (revenues less cash operating expenses and a working capital  
2 adjustment)
- 3 • Operating Cash Flow less spending on property, plant and equipment (Manitoba Hydro  
4 has a target of 1.2x coverage of “ordinary” capital spending needs through internally  
5 generated funds; note that depending on the Plan, many of the years covered will not  
6 be “ordinary”; more discussion of this issue will follow)
- 7 • “Implied Stranded Debt” (this is a purely mathematical calculation which shows the  
8 capitalization at prevailing Manitoba Hydro interest costs of the difference between the  
9 actual interest coverage ratio and the target at 1.2x – further explanation below)

10 The first set of tables depicts the course of Net Income for the five Plans at High/Reference/Low  
11 energy prices.

12 Some notable features include:

- 13 • Plan 1 (All-Gas) has negative net income for the first five years regardless of energy  
14 prices. During this period, the sunk costs of Keeyask and Conawapa are being amortized,  
15 which depresses net income by over \$250 million each year. If the writedown had  
16 occurred all at once in the first year, then there would be a large loss in the first year,  
17 followed by significantly larger Net Income for the remaining years.
- 18 • Plans 4 and 6 include the amortization of the Conawapa sunk costs. Since this is a much  
19 smaller amount than the Keeyask sunk costs, it is not nearly as noticeable in the Net  
20 Income chart.
- 21 • 2019, which is a poor hydrology year, shows negative Net Income for all Plans. This  
22 pattern is repeated for the years 2024 to 2026, which is a drought period. Moreover,  
23 Net Income appears to be directly correlated with energy prices, since Net Income is  
24 lower (i.e., more negative) with lower energy prices.
- 25 • During the drought of the 2030s, however, experience is different. High energy prices in  
26 general cause lower (more negative) Net Income. It should be recalled that each energy

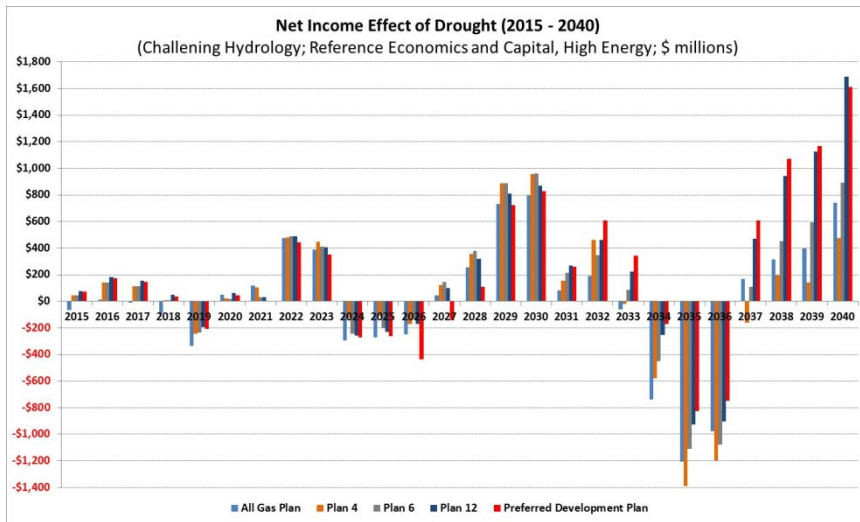
1 scenario is a combination of several variables: export prices, import prices, natural gas  
2 prices and carbon prices. In a High energy scenario, given the severe drought of this  
3 hydrology scenario, all of the Plans would require imports and/or the burning of natural  
4 gas to serve domestic load and firm export contracts. As a result, Manitoba Hydro costs  
5 would rise dramatically. At the same time, during a drought opportunity exports would  
6 fall to a very low level or zero, hence Manitoba Hydro would earn less revenue. The  
7 result is a very significant drop in Net Income. However, in a Low energy price  
8 environment, imports and natural gas would cost less, and while opportunity exports  
9 are also receiving lower prices their volume is negligible to non-existent in a drought  
10 anyway; the result is a less negative Net Income.

- 11 • As between the Plans, the impact on Net Income of energy price scenarios is different.  
12 For the All Gas Plan the impact is relatively minimal, as Manitoba Hydro suffers losses in  
13 11 of the 26 years with High prices, and 13 of 26 years with Reference and Low prices.  
14 However, the impact on the Preferred Plan is much more dramatic, since Manitoba  
15 Hydro suffers losses in only 8 years with High energy prices, but 19 years with Low  
16 energy prices.
- 17 • As might be expected, Plans with more hydroelectric facilities have higher highs when  
18 water is more plentiful (since there will be more opportunity export revenue). However,  
19 in the drought period in the 1930s, Plans with more gas facilities have lower lows when  
20 Energy prices are high (presumably because of the impact of natural gas prices), but the  
21 Preferred Plan has more moderate but more persistent lows when Energy prices are low  
22 (presumably because the loss of export revenue dominates the Net Income effects).

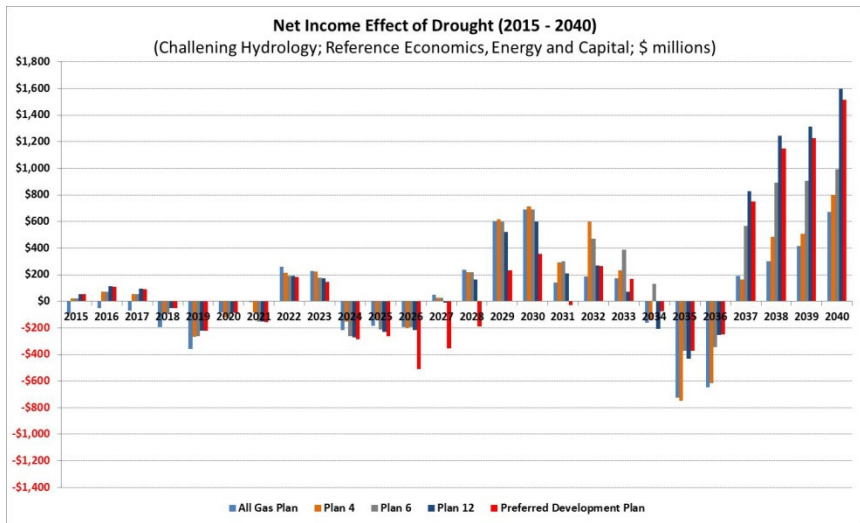
23 Please see the next page.

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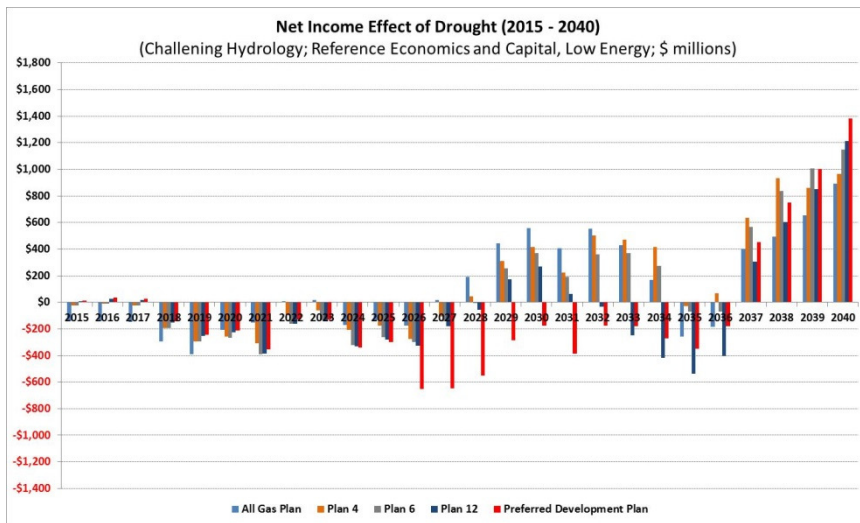
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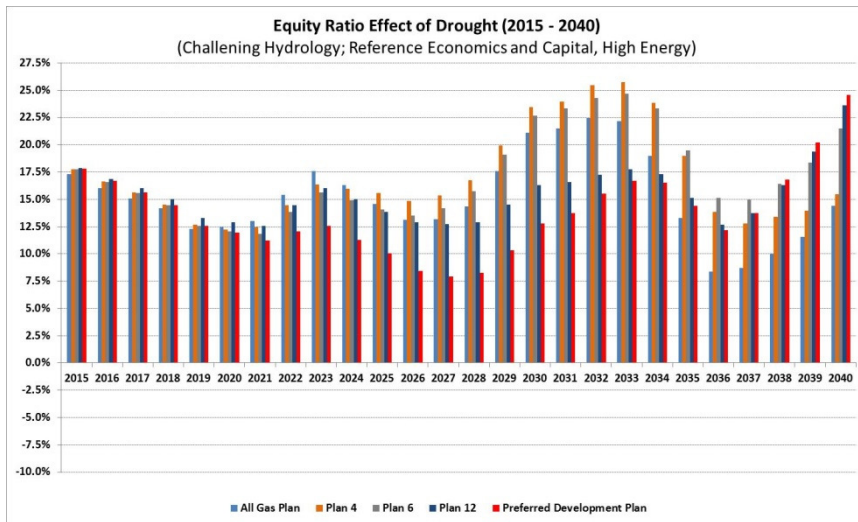
1 The next set of tables depicts the course of the Equity Ratio.

- 2 • None of the Plans, in none of the energy price scenarios, reaches the 25% target Equity  
3 Ratio before 2030 at the earliest. Given the periodic droughts happening throughout the  
4 26 year period, and the consequent financial challenges, it is very difficult for Manitoba  
5 Hydro to reach its targets.
- 6 • Each of the Plans hits its high points in Equity Ratio at different times, depending on the  
7 energy price scenario. For example, in the All Gas Plan, High energy prices result in  
8 stronger performance in the 2020s, but weaker performance in the 2030s versus Low  
9 energy prices. Plan 6 outperforms Plan 4 in the late 2030s with High and Reference  
10 energy prices, but not with Low energy prices.
- 11 • It is immediately apparent that over the whole 26-year period, the equity ratio varies  
12 directly with energy prices. Across Plans, the average equity ratio is higher with High  
13 energy prices, and lower with Low energy prices (however, the exact pattern is different  
14 depending on the Plan). This is consistent with the general conclusion above that the  
15 Plans perform better under High energy prices (with the exception that All Gas varies  
16 relatively little considered as an average over the whole 26 years, but with a different  
17 pattern at each Energy price level).
- 18 • The most negative impact on equity ratio is for the Preferred Plan, which with Low  
19 energy prices reaches negative equity ratios for the entire period from 2026 to 2039.
- 20 • For the All Gas Plan and Plan 4, equity ratio is directly proportional to energy prices in  
21 2020 and 2030 (High energy prices means a higher equity ratio), but inversely  
22 proportional in 2040 (High energy prices means a lower equity ratio). This is likely  
23 caused by the increasing importance of natural gas costs in these plans as the years go  
24 by and more natural gas plants are added.

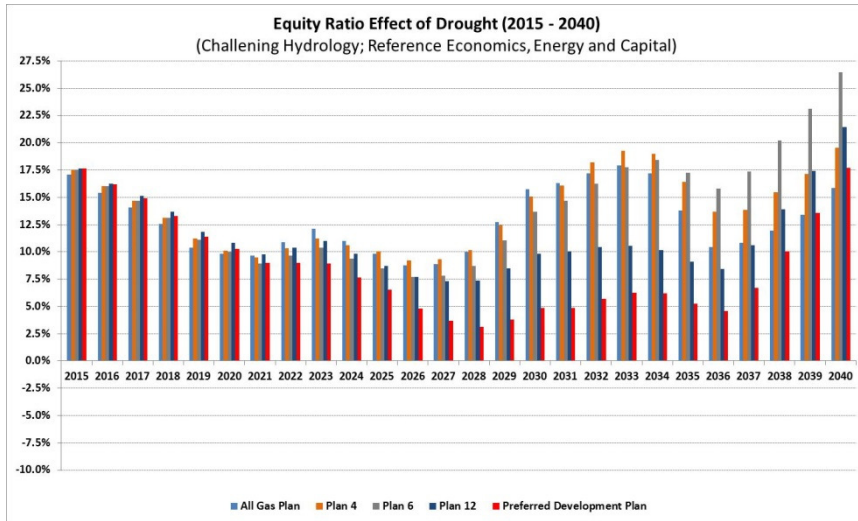
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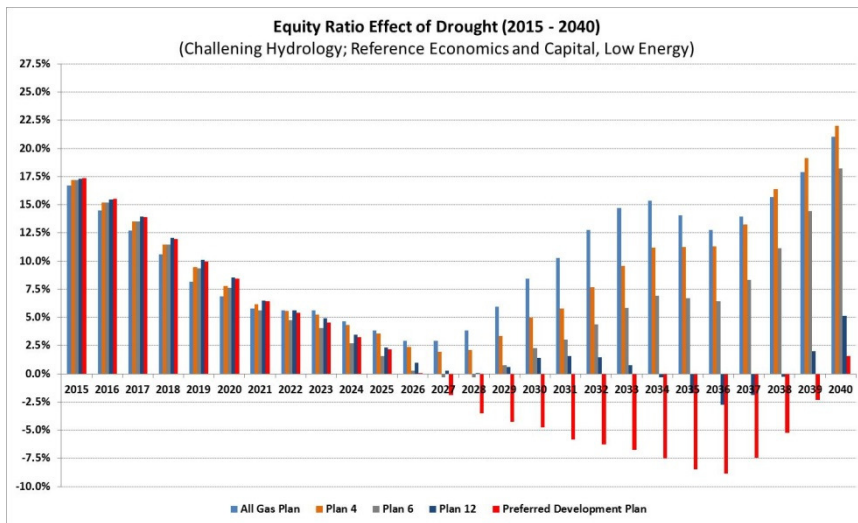
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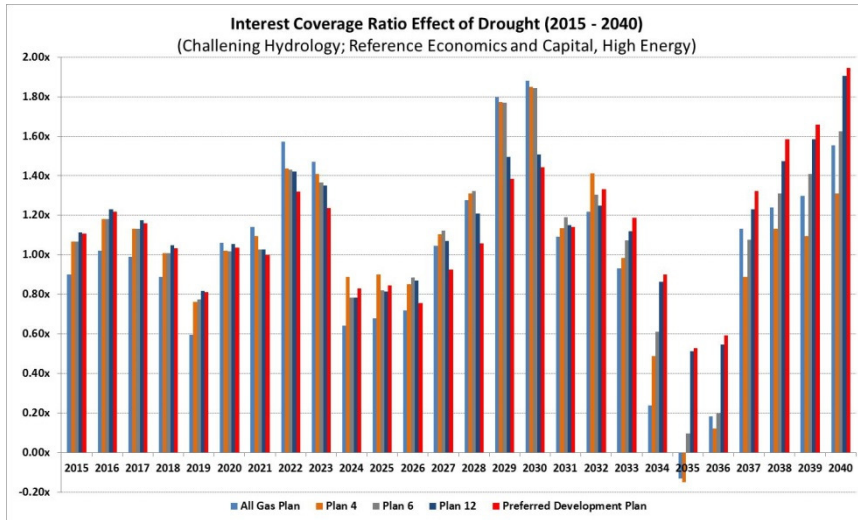
1 The next set of tables addresses the Interest Coverage Ratio.

- 2 • The patterns are generally consistent with those for the equity ratio: typically, Interest  
3 Coverage Ratios are lower with lower energy prices.
- 4 • Only the All Gas Plan and Plan 4 ever have a negative Interest Coverage Ratio, and that  
5 occurs during the depths of the severe drought in the 2030s, with High energy prices.
- 6 • At Reference and Low energy prices, the effects of the 2030s drought are less severe,  
7 even though the average of the ratios are lower over time at these price levels.
- 8 • Under Reference and Low energy prices, the Preferred Plan does not reach the 1.2x  
9 Interest Coverage Ratio until 2037, despite the fact that construction is completed in  
10 2026. With High energy prices, the Preferred Plan does reach the 1.2x Interest Coverage  
11 Ratio target a few times in the late 2020s and early 2030s, before the impacts of the  
12 severe drought are felt. In all cases, once the drought has passed in the later 2030s, the  
13 Preferred Plan's financial performance is very strong (water flow performance is 90%+  
14 every year, and getting stronger at the end of the period).

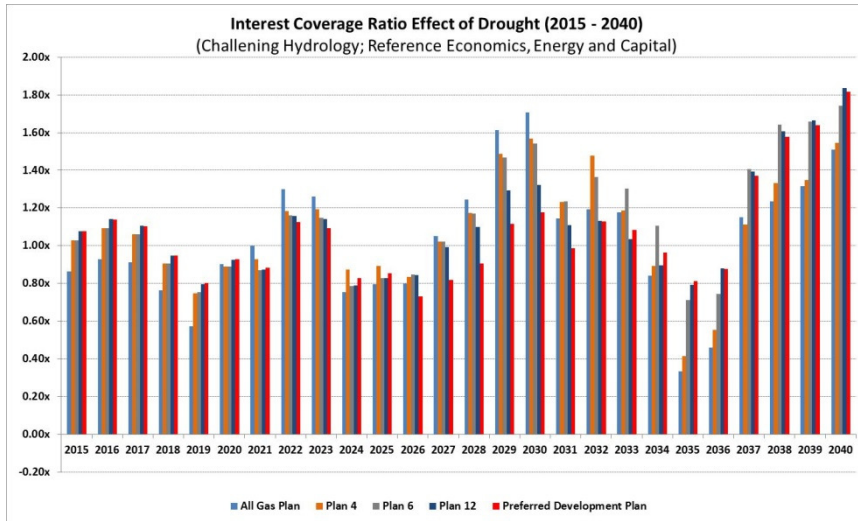
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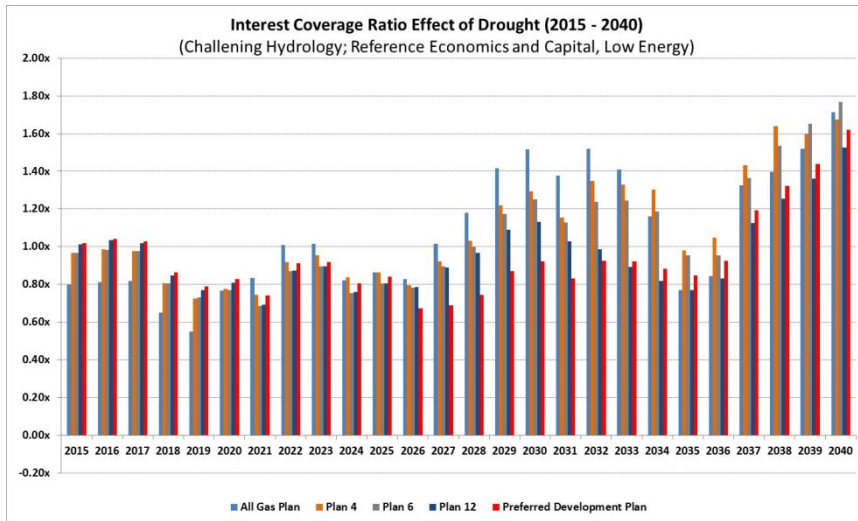
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1 The following pages contain tables for Operating Cash Flow, and Operating Cash Flow less  
2 spending on property, plant and equipment.

- 3 • Operating Cash Flow consists of Revenues less Operating Expenses (such as wages,  
4 materials, interest on debt, etc.), but does not include non-cash items such as  
5 depreciation. If this measure is negative, it means that Manitoba Hydro would have to  
6 borrow money to pay its cash expenses. This happens in only a few cases across all of  
7 the Plans. At High energy prices, negative operating cash flow occurs during the severe  
8 drought of the 2030s at least once across all Plans. At low energy prices, the Preferred  
9 Plan suffers negative cash flow after it comes into service in the late 2020s.
- 10 • Operating Cash Flow less spending on capital goods shows whether Manitoba Hydro  
11 must issue debt to pay for its capital investments. During the construction of major  
12 assets, such as Bipole, Keeyask, Conawapa and new gas plants (for those Plans that have  
13 them), it is to be expected that new debt is required. When major investments are not  
14 underway, however, Manitoba Hydro's target is to not require new debt. Note that  
15 refinancing of existing debt (when it comes due) is not included in this figure. In years in  
16 which operating cash flow is more than enough to cover capital investments, then  
17 Manitoba Hydro would be able to retire debt principal that comes due.
- 18 • The Preferred Plan's operating cash flow is almost always directly proportional to energy  
19 prices, with the exception of during the most severe droughts (when operating cash  
20 flow is worse during high energy prices, presumably because of the cost of imports). In a  
21 Low energy price environment, with this challenging hydrology scenario, Manitoba  
22 Hydro would be an issuer of new debt every year until 2036. Principal payments on debt  
23 would begin only in 2037. This is consistent with the Preferred Plan's performance on  
24 Equity Ratio, as described above. At Reference and High energy prices, Manitoba Hydro  
25 issues less new debt during construction of the Preferred Plan, and actually pays  
26 outstanding debt principal in the early 2030s before the drought sets in.



- 1       • For All Gas, less new debt is issued in total than in the Preferred Plan (which is  
2       consistent with the fact that much less capital is spent under the All Gas Plan). Until  
3       2024, High energy prices mean that less new debt is issued, but after 2025 High energy  
4       prices require more debt to be issued.
  
- 5       • Plans 4 and 6 generally follow the pattern of the All Gas Plan, with High energy prices  
6       being beneficial in the early years, and Low energy prices being beneficial in the later  
7       years. As with the other financial metrics, Plans 4 and 6 are in an intermediate position  
8       as compared to the extremes of the All Gas and Preferred Plans.
  
- 9       • Plan 12, in which Conawapa comes into service in 2031, has extremely large capital  
10      expenditures in the late 2020s, which is apparent from the charts.

11 For reference, the table on the following page provides information on the in-service years for  
12 major infrastructure in each Plan.

13

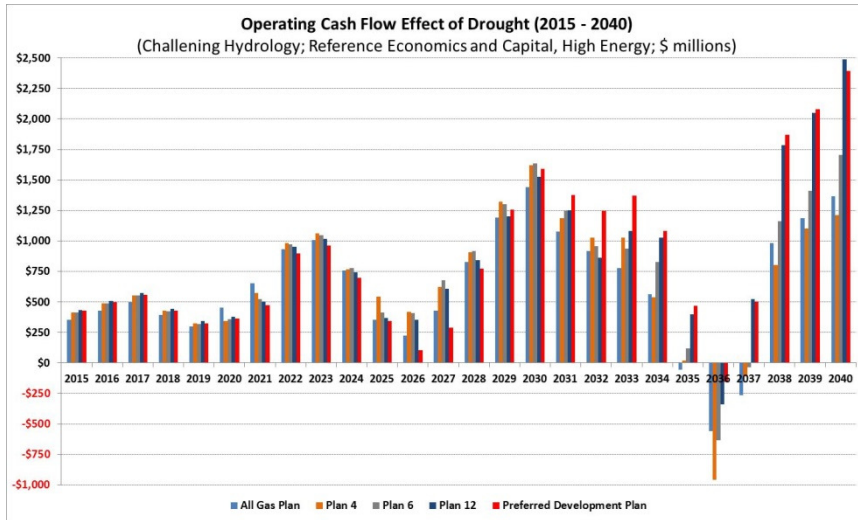
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<b>Year (ending March 31)</b>	<b>All Gas</b>	<b>4</b>	<b>6</b>	<b>12</b>	<b>Preferred</b>
2015					
2016					
2017					
2018	Bipole III	Bipole III	Bipole III	Bipole III	Bipole III
2019					
2020		Keeyask	Keeyask	Keeyask	Keeyask
2021		250 MW Tx	750 MW Tx	750 MW Tx	750 MW Tx
2022					
2023	Single cycle				
2024					
2025		Single cycle			
2026	Single cycle				Conawapa
2027					
2028					
2029	Single cycle				
2030		Single cycle			
2031					
2032	CCGT		Single cycle x2	Conawapa	
2033		CCGT	Single cycle		
2034					
2035	Single cycle		Single cycle		
2036					
2037					
2038	CCGT				
2039		CCGT			
2040			CCGT		

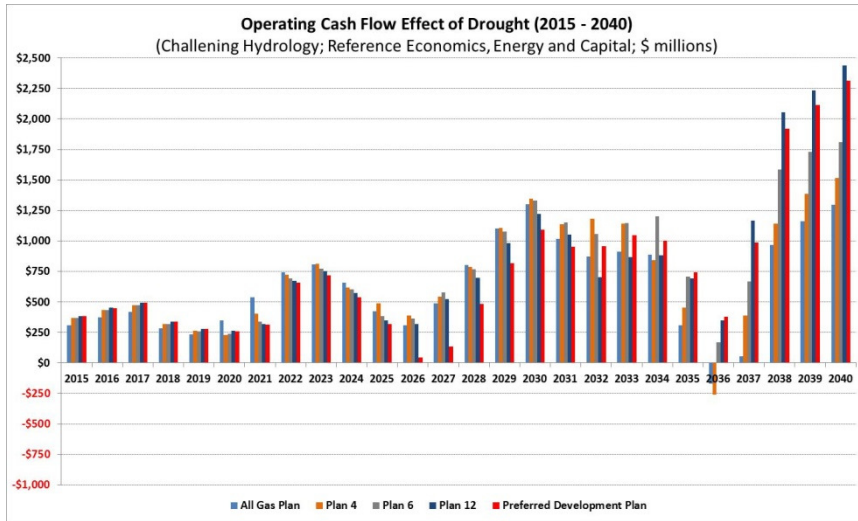
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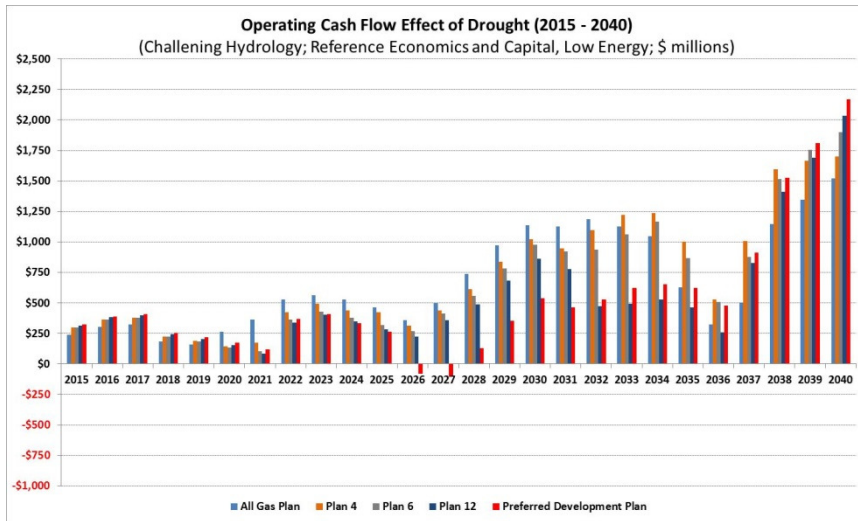
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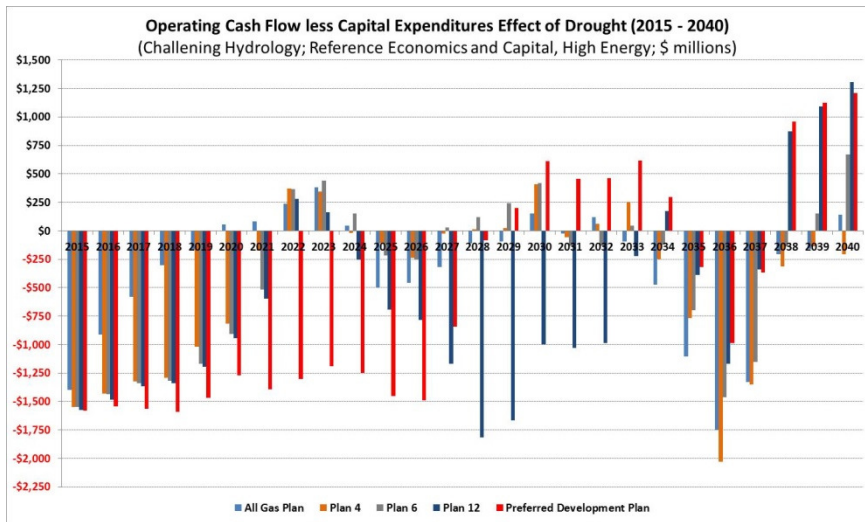
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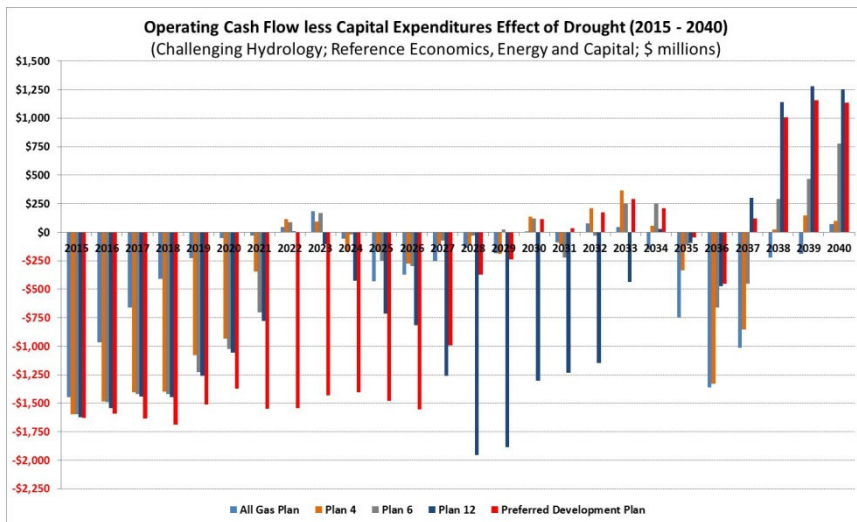
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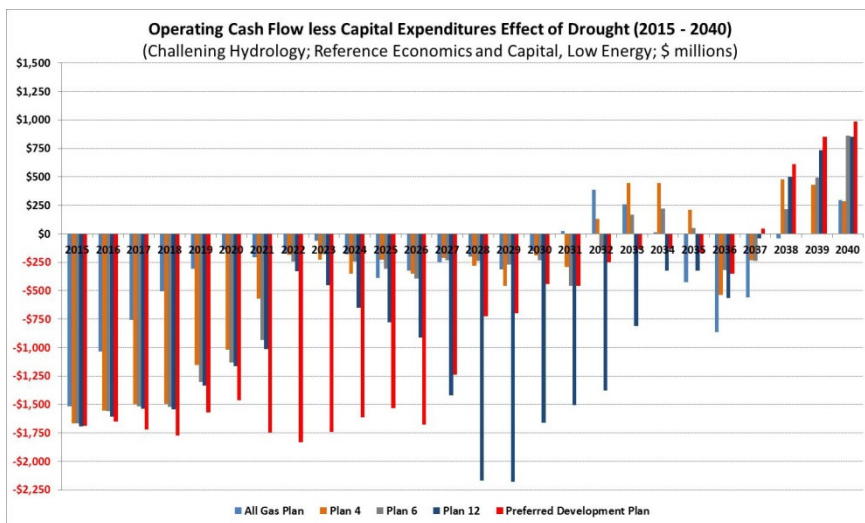
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1 The last item, “Implied Stranded Debt”, requires careful explanation. This is simply a  
2 mathematical calculation, NOT an expression of financial judgement. In many ways, it can be  
3 considered to be the upper boundary of what might be considered by observers to be the debt  
4 at risk at Manitoba Hydro, in a time of financial distress. It is provided here for illustrative  
5 purposes only.

6 Recall that the formula for “Interest Coverage Ratio” is  $(\text{Net Income} + \text{Interest})/\text{Interest}$ .  
7 Manitoba Hydro’s target for this ratio is 1.2x, which means that positive Net Income should be  
8 at least 20% of the size of interest costs in any given year. This is a measure of financial health,  
9 and assuming that this target is built into Manitoba Hydro’s rate planning, it is a “cushion” of  
10 financial resources which could be devoted to debt in the event that revenues are less than  
11 anticipated in any given year.

12 If the Interest Coverage Ratio falls below 1.2x, it means that the targeted financial cushion did  
13 not materialize. It also suggests that Manitoba Hydro’s finances are not as robust as intended.  
14 In the extreme, this relates to the question of whether Manitoba Hydro is “financially self-  
15 supporting”.

16 The calculation for “Implied Stranded Debt” measures how much additional Manitoba Hydro  
17 revenue, or how much of a reduction in expenses, would be required to achieve the 1.2x  
18 Interest Coverage Ratio target (since a problem with Net Income can be solved either by adding  
19 revenue or reducing expenses). This “missing” Net Income is then capitalized at Manitoba  
20 Hydro’s cost of debt (which in the Reference economics scenario is assumed to be 6.30%) to  
21 arrive at the *maximum* implied amount of Manitoba Hydro debt that is not being financially  
22 supported by Manitoba Hydro.

- 23 • At High energy prices, Implied Stranded Debt is very episodic, and very closely  
24 correlated with poor hydrology years across All Plans. High energy prices also exhibit the  
25 highest Implied Stranded Debt figures during the drought of the 2030s.
- 26 • At Low energy prices, Implied Stranded Debt is a much more consistent problem for  
27 most Plans. Given that Implied Stranded Debt is inversely related to the Interest

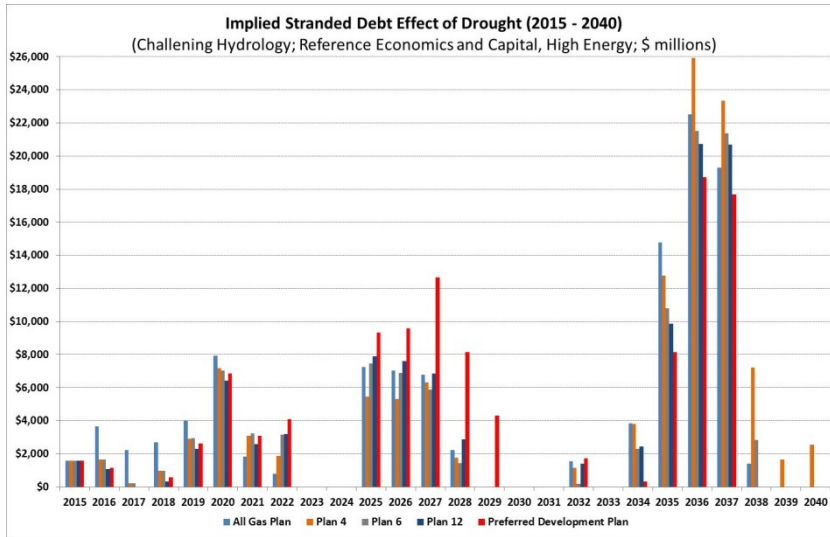
1 Coverage Ratio (i.e., the lower the Interest Coverage Ratio, the Higher the Implied  
2 Stranded Debt), this is not surprising.

3 • The Preferred Plan in the Low energy price scenario suffers from \$10 billion or more of  
4 Implied Stranded Debt from 2025 to 2037, before improved water flow and opportunity  
5 export revenue finally makes the problem disappear.

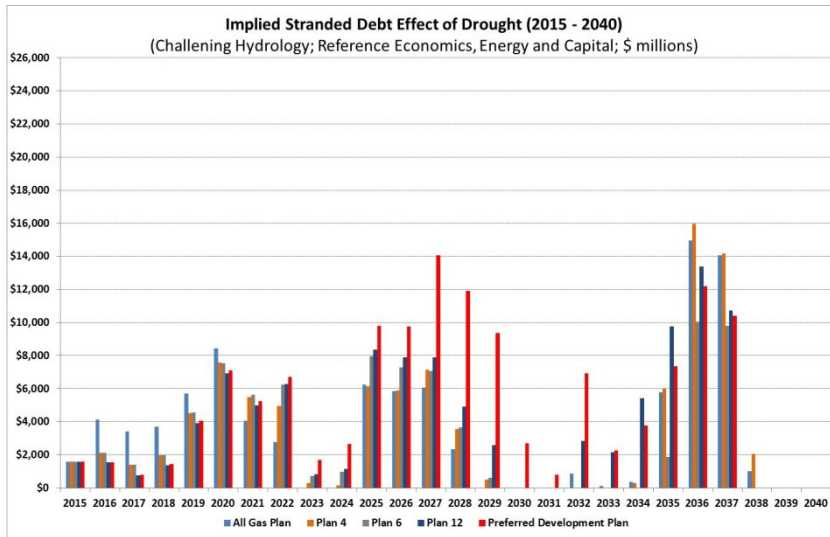
6 • As noted in our Report, financial distress that is closely correlated with drought  
7 conditions – as occurs with High energy prices in the charts below – is unlikely to raise  
8 concerns among financial analysts and credit rating agencies, even if that financial  
9 distress is sharp. However, if financial distress is persistent over time, as is the case in  
10 the Low energy price scenario chart, questions are much more likely to be raised.

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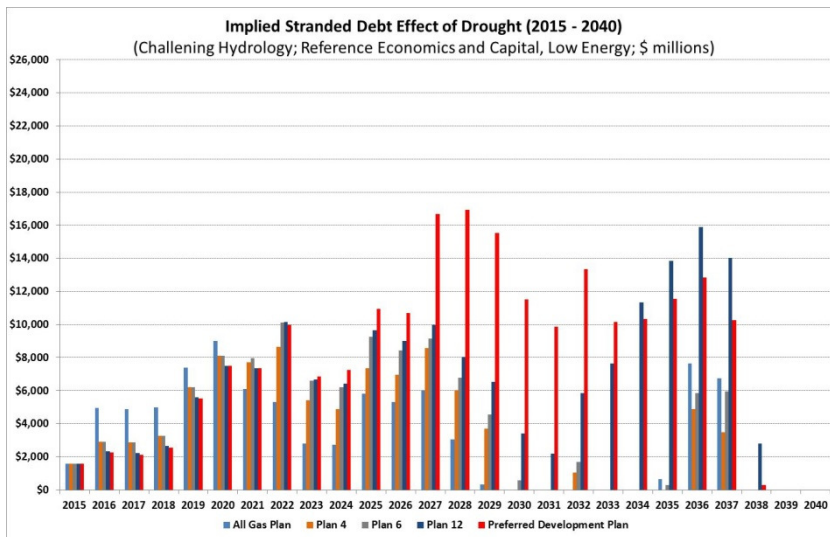
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1 **PUB/MPA 1-027(b)**

2 **REFERENCE:**

3 MPA Report Page 61 Line 18

4 **PREAMBLE:**

5 MPA states :

6 In a "normal situation, Manitoba Hydro's guidelines target not only an interest coverage ratio  
7 of at least 1.2, but also coverage of typical capital spending requirements from internally  
8 generated funds. If the company were not able to meet this objective during a one or two-year  
9 drought, it would be unlikely the credit rating agencies would reassess their position on the  
10 ability of Manitoba Hydro to be self-sustaining. However if drought conditions continued, and  
11 rates were not allowed to rise sufficiently to meet these interest and capital costs, than the  
12 shortfall in meeting them would become a focus for attention.

13 **QUESTION:**

14 For the analysis in (a) please indicate the level of potential MH debt which could be  
15 unsupported

16 **RESPONSE:**

17 Please see the response to PUB/MPA 1-027(a) above.

18



1 **PUB/MPA 1-027(c)**

2 **REFERENCE:**

3 MPA Report Page 61 Line 18

4 **PREAMBLE:**

5 MPA states :

6 In a "normal situation, Manitoba Hydro's guidelines target not only an interest coverage ratio  
7 of at least 1.2, but also coverage of typical capital spending requirements from internally  
8 generated funds. If the company were not able to meet this objective during a one or two-year  
9 drought, it would be unlikely the credit rating agencies would reassess their position on the  
10 ability of Manitoba Hydro to be self-sustaining. However if drought conditions continued, and  
11 rates were not allowed to rise sufficiently to meet these interest and capital costs, than the  
12 shortfall in meeting them would become a focus for attention.

13 **QUESTION:**

14 Please Indicate the potential level of Government support required in each alternative.

15 **RESPONSE:**

16 As noted in PUB/MPA 1-027(a) above, the Implied Stranded Debt that results from a shortfall in  
17 meeting Manitoba Hydro's Interest Coverage Ratio target is one possible way of calculating the  
18 potential level of required government support of Manitoba Hydro. However, as was noted,  
19 this is likely a *maximum* boundary for that potential support.

20 In the charts above, a challenging hydrology scenario was presented, coupled with  
21 High/Reference/Low energy price scenarios. All charts assumed Reference economic variables  
22 (e.g., interest rates and inflation), Reference capital costs (i.e., no cost overruns on  
23 construction), and Reference 2012 demand (i.e., domestic demand growth in Manitoba remains  
24 relatively robust).

25 The scenarios presented in the charts are definitely NOT a "worst case" for any of the Plans. A  
26 "worst case" scenario would include all five of the following:

- 1 • Challenging hydrology with extended periods of severe drought
- 2 • Either High or Low energy prices, depending on whether a Plan is dependent on natural
- 3 gas (in which case High natural gas prices would be damaging) or dependent on
- 4 hydroelectric exports (in which case Low export prices would be problematic).
- 5 • High interest rates putting upward pressure on debt interest costs
- 6 • Cost overruns on major construction projects
- 7 • Low and/or falling domestic demand (which if coupled with export prices lower than
- 8 prevailing domestic rates would put significant upward pressure on domestic rates)

9 The charts above depict the impact of the first two of these situations, but not the other three.

10 Nevertheless, even with only two of the five challenging conditions present, it becomes  
11 apparent that financial distress at Manitoba Hydro can be real.

12 For the All Gas Plan, periods of drought coincide closely with financial distress. Implied  
13 Stranded Debt can reach more than \$20 billion in the severe drought of the 2030s if energy  
14 prices are simultaneously High. However, with Low energy prices, the same drought results in  
15 Implied Stranded Debt of less than \$8 billion. During the shorter drought of the mid-2020s, the  
16 impact is relatively similar regardless of energy prices, at about \$6 billion of Implied Stranded  
17 Debt. In the case of both droughts, Manitoba Hydro's finances recover quickly as soon as the  
18 drought is over.

19 An argument can be made that financial analysts would be reluctant to claim that Manitoba  
20 Hydro is no longer "financially self-supporting" if financial distress appears to be caused solely  
21 by a drought. As long as rates continue to rise at a steady clip (which they are presumed to do  
22 at 3.8% per year), then the financial distress should be presumed to end as soon as water flow  
23 returned to normal. While the Interest Coverage Ratio for the All Gas Plan in 2035 and 2036 is  
24 very bad (it is actually negative in 2035 if energy prices are High, which implies that Manitoba  
25 Hydro would need to borrow to cover operating expenses), it would be considered "expected"

1 that the government would provide assistance to distressed companies in a crisis induced by  
2 drought.

3 During the course of these droughts, Manitoba Hydro could offset some of its financial distress  
4 by seeking higher rates (i.e., increases greater than 3.8%). However, it would not make sense  
5 for the company to raise rates dramatically only to see them fall just as dramatically a few years  
6 later when water flows improved. It is unlikely that such management of rates would be viewed  
7 positively by customers. The alternative is that the government simply provide the debt  
8 necessary for Manitoba Hydro to continue its business, subject to the risk that credit-rating  
9 agencies might consider some portion of that debt to be “unsupported”, and recognize it to be  
10 part of the government’s own “tax-supported debt”.

11 A very different situation presents itself with the Preferred Plan. If energy prices are High, or  
12 even Reference, then instances of financial distress for the Preferred Plan are very much tied to  
13 water flows: in both the drought periods of the mid-2020s and the 2030s, financial distress  
14 represented by the Implied Stranded Debt can reach high levels (as much as \$18 billion in the  
15 2030s). However, financial results improve dramatically with water flows. Similar inferences can  
16 be drawn as those for the All Gas Plan.

17 In the case of Low energy prices, however, the distress faced by the Preferred Plan is arguably  
18 more serious. The drought of the mid-2020s occurs when capital expenditures for Conawapa  
19 are very high, and results in Manitoba Hydro taking on more debt than it otherwise would if it  
20 had more cashflow from internal sources. Even with the recovery in water flows in the late  
21 2020s, Manitoba Hydro’s financial metrics do not recover: Interest Coverage Ratio never  
22 reaches 1.0x, the equity ratio is negative, and internal cash flows are never sufficient to cover  
23 capital expenditures, even though the construction of Conawapa was completed in 2025-26.  
24 Implied Stranded Debt only falls to the \$10 billion range just before the drought of the 2030s  
25 starts, and then the metric deteriorates again.

26 The persistence of the financial distress, even in the face of improving water flows from 2027 to  
27 2030 – and annual rate increases of 3.8% per year – is the critical signal that may raise real

1 questions about the ability of Manitoba Hydro to be financially self-supporting. Absent  
2 significant rate increases, continued financing of Manitoba Hydro by the government may come  
3 to be viewed by financial observers as a tax-supported subsidy. At that point, the  
4 reclassification of up to \$10 billion of Manitoba Hydro debt to the “books” of the government  
5 could become real in the minds of the capital markets. Depending on the financial  
6 circumstances of the Province at that time, this may be easily managed, or not. However, once  
7 the perception of Manitoba Hydro changes, it would take time and effort to reverse the views  
8 of analysts about the financial nature of the corporation.

9

1

2 **PUB/MPA 1-027(d)**

3 **REFERENCE:**

4 MPA Report Page 61 Line 18

5 **PREAMBLE:**

6 MPA states :

7 In a "normal situation, Manitoba Hydro's guidelines target not only an interest coverage ratio  
8 of at least 1.2, but also coverage of typical capital spending requirements from internally  
9 generated funds. If the company were not able to meet this objective during a one or two-year  
10 drought, it would be unlikely the credit rating agencies would reassess their position on the  
11 ability of Manitoba Hydro to be self-sustaining. However if drought conditions continued, and  
12 rates were not allowed to rise sufficiently to meet these interest and capital costs, than the  
13 shortfall in meeting them would become a focus for attention.

14 **QUESTION:**

15 Please elaborate on the amount of reserves the Province should establish for the Preferred  
16 Development Plan and alternatives given the drought impacts determined.

17 **RESPONSE:**

18 As noted in PUB/MPA 1-027(c) above, it is the combination of a drought scenario and a Low  
19 energy price scenario which creates potential financial challenges for the Preferred Plan. In a  
20 High or Reference energy price scenario, it is unlikely that the Preferred Plan would reach such  
21 persistent levels of financial distress that mitigation would be required (note that cost overruns,  
22 unexpectedly low domestic demand or high interest rates could also create challenges for the  
23 Preferred Plan – the point being that drought in and of itself is unlikely to undermine Manitoba  
24 Hydro's finances if the Preferred Plan is adopted).

25 In the case described above of challenging hydrology and Low energy prices, Manitoba Hydro  
26 suffers negative Net Income from 2018 to 2036, unabated. In some years, losses amount to

1 more than \$500 million. These annual losses would register in the Province’s overall income  
2 statement (but are adjusted away by credit rating agencies reviewing the Provincial books  
3 because at least as of now Manitoba Hydro is not considered to be supported by taxes). The  
4 government could reduce the pressure on Manitoba Hydro by reducing or eliminating the debt  
5 guarantee fee, water rental fees, or capital taxes. However, doing any of these things might  
6 create the appearance that the government is subsidizing Manitoba Hydro, which perhaps even  
7 more quickly calls into question Manitoba Hydro’s status as financially self-supporting.  
8 Alternatively, the government could announce that it is temporarily suspending such charges  
9 while water flows are poor and drought conditions are present, and then collecting those  
10 suspended fees in the future from export revenues, when water flows return. In effect, the  
11 government would be “timeshifting” some of Manitoba Hydro’s costs from drought periods to  
12 non-drought periods, in order to lessen both the depth and duration of financial distress.

13 A proactive alternative would be for the government to set up a “drought contingency fund” of  
14 some kind, which would be used to offset Manitoba Hydro’s payments to government during  
15 drought events. After being drawn down, the fund could be replenished through a charge on  
16 export revenues. Initially, the government could create the fund based on the tax revenues it  
17 receives from the economic activity related to construction of the Keeyask and Conawapa  
18 facilities.

19 In the period 2025 to 2035, water rental fees and capital taxes on Manitoba Hydro in the  
20 scenario described above together amount to approximately \$300 million per year. The debt  
21 guarantee fee ranges from \$300 million to \$400 million per year. If these charges were  
22 “suspended” or “delayed” during drought periods, then Manitoba Hydro would be much less  
23 likely to suffer negative net income, it would be closer to achieving its debt ratio targets, and its  
24 equity ratio would not deteriorate so badly. The downside for the government is that these  
25 amounts are real revenue for the government, and the lack of these revenues push the  
26 government’s budget towards deficit (during a drought, there may be other factors also  
27 weighing on the government’s budget, such as support for the agricultural sector, which will  
28 surely be affected by drought as well).

1 Establishing a fund of \$1 billion or more, drawn from whatever source, to be used to offset  
2 losses at Manitoba Hydro suffered during droughts, would be a significant positive step to take  
3 to protect against downside scenarios, such as the one described above for the Preferred Plan.  
4 A fund of that size would be sufficient to offset all water rental fees and capital taxes for three  
5 years, in the event a severe drought. A larger fund would could also offset the debt guarantee  
6 fee, or provide coverage for longer durations. It may well be that such a fund would never be  
7 used, if water flows remain high for many years. In that case, export revenues at Manitoba  
8 Hydro might be high enough to quickly pay off debts, and dramatically reduce the susceptibility  
9 of the company to financial distress. In such a case, the fund could be wound down. However,  
10 having such a fund in place would be insurance against a significant level of financial distress,  
11 and the particularly difficult circumstances that could arise when drought is combined with  
12 other challenges, such as low export prices, or cost overruns.

13 Even in the case of other Plans, having a form of “drought insurance fund” to protect against  
14 losses at Manitoba Hydro would ensure that rate increases are not the only mechanism by  
15 which Manitoba Hydro can mitigate the financial distress that would be caused by inevitable  
16 droughts.

17





**TAB 3**

1 **PUB/MPA 1-030(a)**

2 **REFERENCE:**

3 MPA Report Page 66 Line 29

4 **PREAMBLE:**

5 MH has used a 4.5% equity risk premium in determining its WACC.

6

7 MPA states that given Manitoba Hydro's high degree of exposure to hydrology risk, its financial  
8 exposure to market export prices, and the ambitious construction program including the  
9 preferred development plan, the general issue can be raised with respect to what would  
10 represent a reasonable equity risk premium.

11 **QUESTION:**

12 Please indicate whether MPA believes the equity risk premium used by MH is appropriate. If  
13 not appropriate, what would MPA believe the equity risk premiums should be and MPA's  
14 rationale for its selection.

15 **RESPONSE:**

16 In the calculation of its WACC, Manitoba Hydro has adopted the position that equity should be  
17 priced at 3% above the effective cost of debt in each of the High/Reference/Low economic  
18 scenarios. Based on MPA's calculations, this amounts to approximately 4.5% above the cost of  
19 long Canada bonds.

20 An equity risk premium at this level would be at the extreme low end of the range for regulated  
21 North American utilities, as discussed in section 5.1.1 of our Report. As noted, an Ontario  
22 Energy Board review of this issue concluded that an equity risk premium of 5% above long  
23 Canada bonds would be appropriate for regulated "wires" companies (which in Ontario are  
24 subject to a 60:40 debt to equity capital structure, and are fully rate-regulated).

1 Since Manitoba Hydro's cash flows fluctuate dramatically with hydrology and export prices, and  
2 Manitoba Hydro's target equity ratio is a comparatively thin 25%, the use of an equity risk  
3 premium as low as 4.5% is notable. On the other hand, Manitoba Hydro is governed by "cost of  
4 service" legislation, which nominally requires Manitoba ratepayers to bear all of Manitoba  
5 Hydro's costs, and Manitoba Hydro benefits from a Province of Manitoba guarantee of  
6 substantially all of its debt.

7 Assuming the legislation is accepted at face value and domestic rates could rise to whatever  
8 level were required at any given time to maintain Manitoba Hydro solvency, under any  
9 circumstances, then a legitimate question is whether an "equity risk premium" is applicable?  
10 On its face, the legislation coupled with the provincial debt guarantee suggests that there is no  
11 risk to equity, and hence the premium should be 0%. In reality, however, rates do not rise and  
12 fall annually, but are smoothed over time. This suggests that equity returns should be built into  
13 rate structures to provide a cushion for inevitable swings in cash flow that derive from non-  
14 controllable events, such as hydrology and export prices. Moreover, the possibility of prolonged  
15 financial distress also suggests that equity premiums (and a healthy equity ratio target) are  
16 required.

17 Finally, in the context of the Resource Plans being considered, where in most cases much more  
18 than 75% of capital expenditures will actually be debt funded (which is why the debt ratio is  
19 expected to rise dramatically above 75% for the next 20 years), a higher equity premium that  
20 translates to higher rates will encourage the rebuilding of retained earnings to a healthy level.

21 In our view, the equity risk premium for Manitoba Hydro should be at least 5% above Canada  
22 Long Bonds, and we argue should be targeted to 6% for all of the reasons discussed.

23 Combining our views on interest rates and the equity premium results in the following views on  
24 WACC:

**Alternative WACC Calculation**

	Ratio	Nominal			Inflation			Real		
		High	Ref	Low	High	Ref	Low	High	Ref	Low
<b>Debt</b>	75%	8.90%	6.60%	4.30%	3.00%	2.00%	1.00%	5.73%	4.51%	3.27%
<b>Equity</b>	25%	13.00%	11.00%	9.00%	3.00%	2.00%	1.00%	9.71%	8.82%	7.92%
<b>WACC</b>	100%	9.93%	7.70%	5.48%				6.72%	5.59%	4.43%

1

2 As compared to Manitoba Hydro’s suggested WACC calculation (9.70%, 7.05% and 4.40%), our  
 3 views lead to a substantially higher Low scenario, a moderately higher Reference scenario, and  
 4 a High scenario that is almost identical to Manitoba Hydro.

5 The practical impact of assuming a higher equity risk premium and hence a higher WACC in our  
 6 financial models would be that in all scenarios rate increases continue at double the rate of  
 7 inflation for a period longer than they otherwise would. However, subsequent rate pressures in  
 8 the face of shocks would be moderated.

9 In terms of the impact on choices between Resource Plans, driving up the WACC would tend to  
 10 comparatively favour Plans which are less capital intensive. Consistent with the analysis in our  
 11 report, in the High economics scenario, where WACC is higher, the Preferred Plan performs  
 12 worse comparatively to other Plans than when the WACC is lower (in the Low economics  
 13 scenario).

1 **PUB/MPA 1-030(b)**

2 **REFERENCE:**

3 MPA Report Page 66 Line 29

4 **PREAMBLE:**

5 MH has used a 4.5% equity risk premium in determining its WACC.

6

7 MPA states that given Manitoba Hydro's high degree of exposure to hydrology risk, its financial  
8 exposure to market export prices, and the ambitious construction program including the  
9 preferred development plan, the general issue can be raised with respect to what would  
10 represent a reasonable equity risk premium.

11 **QUESTION:**

12 Please indicate how the revised equity risk premium would manifest itself in the reference and  
13 high discount rate used in the NPV analysis.

14 **RESPONSE:**

15 Please see the response to PUB/MPA 1-030(a) above.

16

1 **PUB/MPA 1-030(c)**

2 **REFERENCE:**

3 MPA Report Page 66 Line 29

4 **PREAMBLE:**

5 MH has used a 4.5% equity risk premium in determining its WACC.

6

7 MPA states given Manitoba Hydro high degree of exposure to hydrology risk, its financial  
8 exposure to market export prices, and the ambitious construction program including the  
9 preferred development plan, the general issue can be raised with respect to what would  
10 represent a reasonable equity risk premium

11 **QUESTION:**

12 How would a change in probability weighting and discount rates impact on the ratepayer  
13 impacts for the five plans.

14 **RESPONSE:**

15 Please see the response to PUB/MPA 1-030(a) above.

16

TAB 4

*Bonneville Power Administration Annual Report  
2016, available at:*

<https://www.bpa.gov/Finance/FinancialInformation/AnnualReports/Documents/AR2016.pdf>

**(Source: as referenced in errata to MPA Report,  
Exhibit [CC-17-1](#))**



TAB 5

*Long Island Power Authority 2016 Annual  
Report, available at:*

[http://www.lipower.org/pdfs/company/LIPA  
%20Annual%20Report%202016.pdf](http://www.lipower.org/pdfs/company/LIPA%20Annual%20Report%202016.pdf)

**(Source:** as referenced in errata to MPA Report,  
Exhibit [CC-17-1](#))

**TAB 6**

*Santee Cooper 2016 Annual Report*, available  
at:

[https://www.santeecooper.com/About-Santee-Cooper/Communications/pdfs/2016AR\\_FULL.pdf](https://www.santeecooper.com/About-Santee-Cooper/Communications/pdfs/2016AR_FULL.pdf)

(**Source:** as referenced in errata to MPA Report,  
Exhibit [CC-17-1](#))

**TAB 7**

# The Manitoba Hydro-Electric Board



## Ratings

**Tom Li**  
 +1 416 597 7378  
 tli@dbrs.com

**Ravikanth Rai**  
 +1 416 597 7388  
 rrai@dbrs.com

*Insight beyond the rating.*

Debt	Rating	Trend
Long-Term Obligations	A (high)	Stable
Short-Term Obligations	R-1 (middle)	Stable

Note: These Obligations are based on the status of the Manitoba Hydro-Electric Board as a Crown agent of the Province of Manitoba and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt, and thus reflect the Province's debt ratings.

## Rating Update

DBRS Limited (DBRS) has updated its report on the Manitoba Hydro-Electric Board (Manitoba Hydro or the Utility). The ratings assigned to the Utility's Long-Term Obligations and Short-Term Obligations are a flow-through of the ratings of the Province of Manitoba (the Province; rated A (high) and R-1 (middle) with Stable trends by DBRS). Pursuant to *The Manitoba Hydro Act*, the Province unconditionally guarantees almost all of Manitoba Hydro's outstanding third-party debt (please see the *DBRS Criteria: Guarantees and Other Forms of Support* methodology for further details). The Province also provides most of the Utility's financing through provincial advances (approximately 99% of total debt as at March 31, 2016). DBRS considers Manitoba Hydro to be self-supporting, as it is able to fund its own operations and service debt obligations.

In early 2016, Manitoba Hydro engaged the Boston Consulting Group to conduct a review of its financial, operating and capital plans, with particular focus on the Bipole III Transmission Reliability Project (Bipole III), the Keeyask Infrastructure and Generating Station Project (the Keeyask Project) and the Manitoba-Minnesota Transmission Project (MMTP). The results, issued in September 2016 (the BCG Report), concluded

that although the decision to proceed with the Keeyask Project was imprudent as some major risks were not fully considered, the best path forward was to continue construction on all three projects. The BCG Report noted, however, that total cost overruns of \$1 billion could occur along with possible delays to the in-service dates of 12 months for Bipole III and 21 months for the Keeyask Project. The BCG Report also noted the rising leverage at the Utility as a result of the substantial capex; debt-to-capital at Manitoba Hydro had risen to 83% at F2016 and had been expected to peak at 88%, significantly above the target capital structure of 75% debt. A new board appointed at Manitoba Hydro in 2016 intends to limit the deterioration in the Utility's balance sheet. As a result, the Utility has begun reviewing initiatives to help alleviate pressure on its key financial ratios, such as improving operational efficiencies, requesting annual rate increases higher than the previously planned 3.95%, as well as a potential equity injection from the Province. DBRS sees these initiatives, if actualized, as positive to Manitoba Hydro's financial profile, as they will provide some financial flexibility for the Utility, especially in the event of adverse drought conditions or further cost overruns on the projects.

Continued on P. 2

## Financial Information

### The Manitoba Hydro-Electric Board

For the year ended March 31 <sup>1</sup>

(CAD millions where applicable)	<u>2016</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>	<u>2012</u>
Total debt in capital structure <sup>2</sup>	83.0%	81.3%	79.4%	78.5%	77.9%
Cash flow/Total debt	5.4%	5.3%	6.4%	6.1%	6.3%
EBIT gross interest coverage (times)	0.91	1.07	0.96	0.89	0.80
Net income before non-recurring items	55	145	178	92	61
Cash flow from operations	791	665	691	589	567

<sup>1</sup> 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. <sup>2</sup> Adjusted for other comprehensive income.

## Issuer Description

The Manitoba Hydro-Electric Board, a wholly owned Crown corporation of the Province of Manitoba, is a vertically integrated electric utility that provides generation, transmission and distribution of electricity to approximately 567,634 customers throughout Manitoba, and natural gas service to approximately 276,858 customers via its subsidiary, Centra Gas Manitoba Inc. The Utility also exports electricity to more than 25 electric utilities through its participation in four wholesale markets in Canada and in the Midwestern United States.

## Rating Update (CONTINUED)

DBRS continues to view Manitoba Hydro as self-supporting, as its earnings and cash flows continue to be sufficient to cover its operating expenses and to service its outstanding debt. However, DBRS could consider reclassifying a portion of the Utility's debt to be tax-supported should the financial health of the Utility deteriorate to the point where its expenses cannot be recovered

through rates. If this were to occur, it could potentially put downward pressure on the Province's credit rating. Similarly, a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province's credit profile. At this time, however, DBRS expects the Province's ratings to remain stable.

## Rating Considerations

### Strengths

#### 1. Debt is a direct obligation of the Province

Manitoba Hydro is an agent of the Crown, and its debt securities, except for \$65 million of Manitoba Hydro-Electric Board Bonds (less than 1% of total debt at March 31, 2016), are held or guaranteed by the Province; therefore, the ratings assigned to Manitoba Hydro's obligations are a flow-through of the ratings assigned to the Province.

#### 2. Low-cost hydro-based generation

Low-cost hydroelectric-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its domestic customers at one of the lowest rates on the continent. This gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened capex requirements.

#### 3. Access to export markets

Manitoba Hydro's interconnections (approximately 43% of installed capacity), with firm export transfer capability of 2,100 megawatts (MW) to the United States, 175 MW to Saskatchewan and 200 MW to Ontario, along with additional non-firm transfer capability, provide the Utility with access to favourable export markets. The interconnections also provide a secure supply of electricity for domestic customers during times of poor hydrology.

### Challenges

#### 1. High leverage

Leverage at Manitoba Hydro has been increasing over the past years as a result of the significant capital projects currently being undertaken. As such, the debt-to-capital ratio reached 83% at F2016, above the target capital structure of 75% debt. The Utility had forecast leverage to peak at 88% when the Keeyask Project is brought in service, but with the possibility of cost overruns and delays detailed in the BCG Report for Bipole III and the Keeyask Project, leverage could potentially further increase if mitigants are not enacted. The Utility is currently reviewing potential initiatives, such as requesting higher rate increases or an equity injection from the Province, which could help alleviate pressure on its key financial ratios.

#### 2. High level of planned capex

The Utility is currently undergoing a period of substantial capex, with major projects that include Bipole III (total capex of approximately \$4.65 billion) and the Keeyask Project (total capex of approximately \$6.5 billion). As a result, capex for the Utility had been forecast to average approximately \$2.4 billion per year before falling to \$900 million beginning in F2022. However, the BCG Report notes that total capex for Bipole III could increase to \$5 billion, while the Keeyask Project could reach \$7.8 billion. As such, average capex for the medium term may continue to climb and further pressure the already high debt levels.

#### 3. Hydrology risk

Given that approximately 92% of Manitoba Hydro's installed generating capacity is hydroelectricity-based, earnings and cash flows are highly sensitive to hydrological conditions. The Utility is also exposed to significant price and volume risk because of its export commitments under the fixed price-to-volume contract, which may require the Utility to procure power supply from import markets if hydrological conditions are unfavourable.

## Major Projects (Under Construction and Planned)

Project	Estimated Cost (\$ millions)	Planned Construction Start Date	In-Service Target Date
Bipole III Transmission Reliability Project	4,650	2013	2019
Keeyask Infrastructure and Generating Station Projects	6,500	2014	2021
Manitoba-Minnesota Transmission Project	450	2017	mid-2020

- Bipole III:** This project involves the construction of a 500-kilovolt (kV) high-voltage direct current transmission line, along with new converter stations. Construction began during winter 2013/2014, and the transmission line is expected to be in service for 2018. The BCG Report noted that the cost for the project may increase to approximately \$5 billion with the in-service date delayed until mid-2019.
- Keeyask Project:** This project includes the development of a 695 MW generation station on the Nelson River. Construction began in July 2014; the first generator is expected to be in service for 2019 and the remaining units are expected to be in service by 2021. The BCG Report noted that the cost for the project may increase to approximately \$7.8 billion with the in-service date delayed until mid-2021.
- MMTP:** This proposed project involves the construction of a 500 kV alternating current transmission line from Winnipeg to the Manitoba-Minnesota border, where it will interconnect with the Great Northern Transmission Line (GNTL) to be built by Minnesota Power. The Province authorized Manitoba Hydro to proceed with the project in July 2014, and the Utility filed an Environmental Impact Statement in September 2015, which began the formal regulatory review process. Minnesota Power has received all major regulatory approvals for the GNTL including a Presidential Permit, and expects to start construction early in 2017.



## Earnings and Outlook

For the year ended March 31 <sup>1</sup>

(CAD millions where applicable)	<b>2016</b>	<b>2015</b>	<b>2014</b>	<b>2013</b>	<b>2012</b>
Total electricity revenues	1,791	1,812	1,861	1,733	1,573
Net gas revenues	172	161	163	147	132
<b>Total revenues</b>	<b>1,963</b>	<b>1,973</b>	<b>2,024</b>	<b>1,880</b>	<b>1,705</b>
EBITDA	983	990	1,068	991	865
EBIT	595	621	626	568	484
Gross interest expense	654	581	654	636	603
Earning before taxes	45	134	156	79	61
Net income before non-recurring items	55	145	178	92	61
Reported net income	49	136	174	92	61
Return on equity <sup>2</sup>	1.9%	5.0%	6.6%	3.5%	2.4%

<sup>1</sup> 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. <sup>2</sup> Adjusted for other comprehensive income.

### F2016 Summary

- Earnings declined in F2016 as milder winter temperature for the period reduced revenues from both the domestic electric and natural gas segments, while depreciation and interest expense rose from the continued high capex.
  - This was slightly offset by a 3.95% rate increase effective August 1, 2015.
- DBRS expects the Utility's profitability to remain challenged over the medium term as the Utility continues to invest significant amounts for Bipole III and the Keeyask Project. However, the new board at Manitoba Hydro appointed earlier in 2016 intends to improve leverage at the Utility back to the target debt-to-capital ratio of 75%.
  - While Manitoba Hydro had planned to file for more moderate annual rate increases of 3.95% until F2029, the Utility is currently considering requesting higher rate increases for the next few years to help improve the leverage ratio. DBRS had noted that rate increases of 3.95% were expected to be insufficient for Manitoba Hydro to recover costs related to major projects for the medium term.
  - Other initiatives include the plan to reduce the workforce (approximately 6,000 employees), largely through attrition and managing vacancies, to help contain operating costs at the Utility.

### F2017 Outlook

- Manitoba Hydro has forecast earnings in F2017 to remain low, with expected net income of approximately \$25 million. While rates increased by 3.36% effective August 1, 2016, this will likely be more than offset by rising depreciation and interest costs.
  - The Utility had requested a rate increase of 3.95% effective April 1, 2016. The delay in implementation and lower approved increase will also have a negative impact on earnings.

## Financial Profile

For the year ended March 31 <sup>1</sup>

(CAD millions where applicable)	<b>2016</b>	<b>2015</b>	<b>2014</b>	<b>2013</b>	<b>2012</b>
Cash receipts from customers	2,298	2,359	2,176	2,015	1,998
Cash paid to suppliers and employees	(950)	(1,203)	(1,053)	(981)	(1,048)
Interest paid	(580)	(517)	(502)	(489)	(418)
Interest received	23	26	70	44	35
<b>Cash flow from operations</b>	<b>791</b>	<b>665</b>	<b>691</b>	<b>589</b>	<b>567</b>
Dividends paid	0	0	0	0	0
Capital expenditures	(2,280)	(1,730)	(1,394)	(1,037)	(1,124)
<b>Free cash flow</b>	<b>(1,489)</b>	<b>(1,065)</b>	<b>(703)</b>	<b>(448)</b>	<b>(557)</b>
Acquisitions & investments	(89)	(105)	(103)	(98)	(90)
Net sinking fund withdrawals/(payments)	114	(3)	206	22	(75)
Net debt change	1,803	1,556	707	565	673
Other	123	(31)	3	(59)	29
<b>Change in cash</b>	<b>462</b>	<b>352</b>	<b>110</b>	<b>(18)</b>	<b>(20)</b>
Total debt (net sinking fund investments)	14,527	12,566	10,757	9,633	9,010
Cash and equivalents	953	487	142	32	50
Total debt in capital structure <sup>2</sup>	83.0%	81.3%	79.4%	78.5%	77.9%
Cash flow/Total debt	5.4%	5.3%	6.4%	6.1%	6.3%
EBIT gross interest coverage (times)	0.91	1.07	0.96	0.89	0.80
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

<sup>1</sup> 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. <sup>2</sup> Adjusted for other comprehensive income.

### F2016 Summary

- Manitoba Hydro's key financial ratios weakened in F2016 largely because of the increase in debt to fund the large capex requirements.
- Cash flow from operations increased in F2016 from higher payable balances related to the capex projects and to the lower cost of gas and purchase gas costs caused by warmer weather.
- Gross capex of \$2.4 billion included \$872 million for Bipole III and \$742 million for the Keeyask Project.
- The significant free cash flow deficit for the fiscal period was funded through advances from the Province.

### F2017 Outlook

- Manitoba Hydro's key financial ratios are expected to remain weak for the medium term as it continues its large capex program. While the debt-to-capital ratio had been forecast to peak at 88% in F2022, the Utility is currently reviewing potential initiatives to help improve its financial health.
  - Manitoba Hydro is seeking to identify internal efficiencies to improve operating results.
  - The Utility may request higher annual rate increases than the planned 3.95% in order to improve its earnings and cash flows.

- A potential equity injection from the Province would also help alleviate pressure on Manitoba Hydro's leverage.
- Manitoba Hydro has forecast capex of approximately \$3.5 billion for F2017, including around \$1.5 billion for Bipole III and \$1.1 billion for the Keeyask Project.
  - The Utility had forecast capex to peak in F2017 and F2018 (\$3.1 billion) when Bipole III comes in service. It had also forecast capex to moderate to around \$900 million a year following the in-service date of the Keeyask Project in F2021.
  - However, the BCG Report estimates that an additional approximately \$1 billion may be needed for the two projects to be completed. As well, the BCG Report also expects delays to the in-service date of the two projects.
- The high level of capex is expected to result in continued negative free cash flows, which will likely be funded through advances from the Province. Without a corresponding increase in equity, either through higher earnings or an equity injection from the Province, the increasing debt load could further weaken Manitoba Hydro's key financial ratios.
  - The Utility does have some financial flexibility, as it has no mandatory dividend payment requirements.

## Long-Term Debt Maturities and Bank Lines

For the year ended March 31

<b>Debt Profile</b> (CAD millions)	<b>%</b>	<b>2016</b>	<b>2015</b>	<b>2014</b>
Advances from the Province	98.8%	14,437	12,485	10,683
Manitoba Hydro Bonds	0.2%	26	76	169
Manitoba Hydro-Electric Board Bonds*	1.0%	145	157	158
	<b>100.0%</b>	<b>14,608</b>	<b>12,718</b>	<b>11,010</b>
Other adjustments		(81)	(38)	(142)
<b>Total</b>		<b>14,527</b>	<b>12,680</b>	<b>10,868</b>

\* Includes \$65 million of unguaranteed bonds at March 31, 2016.

### Debt Maturities

Year	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Thereafter</b>	<b>Total</b>
(CAD millions)	326	331	996	345	1,299	11,311	<b>14,608</b>
%	2%	2%	7%	2%	9%	78%	<b>100%</b>

### Summary

- The Province supports Manitoba Hydro by advancing funds or guaranteeing the Utility's long-term debt issuances. Long-term debt at March 31, 2016, consisted of the following:
  - \$14,437 million in advances from the Province (all of which have annual sinking fund requirements).
  - \$26 million of Manitoba Hydro Bonds.
  - \$145 million of Manitoba Hydro-Electric Board Bonds.
- Only \$65 million of Manitoba Hydro-Electric Board Bonds, which were issued for mitigation projects, do not carry the provincial guarantee.
- Manitoba Hydro maintains a relatively smooth maturity profile with potential volatility from foreign currency debt, mostly mitigated through natural and cash flow hedges and a moderate level of floating-rate debt (10% of total debt at March 31, 2016), which adds stability to debt servicing costs and minimizes interest rate risk.
- The Utility has bank credit facilities that provide for overdrafts and notes payable of up to \$500 million denominated in Canadian and/or U.S. dollars. At March 31, 2016, there were no amounts outstanding. Manitoba Hydro issues short-term promissory notes in its own name for its short-term cash requirements and does not receive short-term funding from the Province. These short-term notes are guaranteed by the Province.

## Regulation

Manitoba Hydro is governed by *The Manitoba Hydro Act*, and its electricity and natural gas rates are regulated by the Public Utilities Board (PUB).

### Electricity

- Each year, Manitoba Hydro reviews its financial targets with particular focus on its debt-to-equity target capital structure of 75% to 25%. If the Utility deems a rate adjustment necessary to continue progress toward attaining its financial targets, it submits a rate application to the PUB.
- The PUB reviews the rate adjustment application with the objective of allowing Manitoba Hydro to recover its cost of service and achieve its long-term debt-to-equity target. The PUB does not have the mandate to pre-approve capex. The capex planning responsibility resides with Manitoba Hydro and the government of Manitoba.
- Manitoba Hydro submitted its 2015/16 & 2016/17 General Rate Application (GRA) in January 2015, requesting 3.95% rate increases effective April 1, 2015, and April 1, 2016.
  - The PUB advised the Utility that it would not set rates for 2016/17 as part of this application.
  - On July 24, 2015, the PUB finalized the previously approved interim rate increase of 2.75% effective May 1, 2014, and approved a 3.95% increase in rates effective August 1, 2015. In its decision, the PUB indicated that it would consider various options regarding a process to review rates effective for April 1, 2016.
  - For the 2015 rate increase, the PUB directed 1.80% of the revenues associated with the rate increase to be applied to general revenues, and for the remaining 2.15% to be placed in a deferral account to mitigate rate increases when Bipole III comes in service. This was similar to the PUB's direction for rate increases approved in 2013/14 and 2014/15, where a portion of the revenues was also allocated to the Bipole III deferral account.
- On November 18, 2015, the Utility submitted its Supplemental Filing for Interim Rates effective April 1, 2016, requesting a 3.95% general rate increase.
  - In April 2016, the PUB approved an interim rate increase of 3.36% effective August 1, 2016.
  - Manitoba Hydro expects to file its 2016/17 and 2017/18 GRA in early 2017.

- While Manitoba Hydro is the sole retail electricity supplier in Manitoba, under *The Manitoba Hydro Amendment Act* (the Act), other utilities may access the transmission system to reach customers in neighbouring provinces and states.
- The Act also explicitly allows Manitoba Hydro to build new generating capacity for export sales, to offer new energy-related services, to enter into strategic alliances and joint ventures, and to create subsidiaries.
- There are presently no plans to move to full retail competition in the Province.
- Manitoba retail customers currently enjoy rates that are among the lowest in North America as a result of Manitoba Hydro's predominantly hydroelectric generation and efficient resource management.

### Natural Gas Distribution

- Manitoba Hydro distributes natural gas through its wholly owned subsidiary, Centra Gas Manitoba Inc. (Centra Gas). In accordance with the rate-setting methodology for natural gas, commodity rates are changed every quarter based on 12-month forward natural gas market prices.
  - The commodity cost of gas is a pass-through with no markup to customers.
  - Non-commodity costs, such as transportation and storage are also passed on.
- The PUB allows Centra Gas to target an annual profit of approximately \$3 million, which is fairly modest compared with Manitoba Hydro's consolidated earnings.
- Centra Gas filed its 2015/16 Cost of Gas Application in June 2015, requesting, effective November 1, 2015, the approval of supplemental gas, transportation and distribution rates, including rate riders to dispose of balances in its non-Primary Gas deferral accounts.
  - In October 2015, the PUB approved, on an interim basis, new rates for supplemental gas, transportation and distribution, as well as rate riders to dispose of the balance in the non-Primary Gas deferral accounts.

## Watershed Storage Capacity

Manitoba Hydro draws water from five distinct watersheds: Nelson River, Winnipeg River, Saskatchewan River, Churchill River (including the Laurie River) and Burntwood River. This provides the Utility with some geographic diversification, especially during times of low hydrology. The main generation source is the Nelson River, which accounted for approximately 78% of power generated in F2016.

### Source of Electrical Energy Generated and Imported

For the year ended March 31, 2016

<b>Nelson River</b>	<b>78.32%</b>	<b>Saskatchewan River</b>	<b>4.25%</b>
<b>Billion kWh generated</b>	<b>28.1</b>	<b>Billion kWh generated</b>	<b>1.5</b>
Limestone	25.26%	Grand Rapids	4.25%
Kettle	24.04%		
Long Spruce	20.08%	<b>Laurie River</b>	<b>0.10%</b>
Kelsey	6.62%	<b>Billion kWh generated</b>	<b>0.0</b>
Jenpeg	2.32%	Laurie River #1	0.05%
		Laurie River #2	0.05%
<b>Winnipeg River</b>	<b>10.45%</b>		
<b>Billion kWh generated</b>	<b>3.8</b>	<b>Burntwood River</b>	<b>4.10%</b>
Seven Sisters	3.21%	<b>Billion kWh generated</b>	<b>1.5</b>
Great Falls	2.31%	Wuskwatim	4.10%
Pine Falls	1.75%		
Pointe du Bois	0.80%		
Slave Falls	1.15%		
McArthur	1.23%		
<b>Thermal</b>	<b>0.16%</b>	<b>Purchases (excl. wind)</b>	<b>0.24%</b>
<b>Billion kWh generated</b>	<b>0.1</b>	<b>Billion kWh imported</b>	<b>0.1</b>
Brandon	0.14%		
Selkirk	0.02%	<b>Wind</b>	<b>2.38%</b>
		<b>Billion kWh</b>	<b>0.9</b>

Source: Manitoba Hydro

Favourable characteristics inherent in Manitoba Hydro's watersheds include the following:

- Cold temperatures reduce overall evaporation rates, as many of the reservoirs are frozen over for up to five months of the year.
- A significant portion of the watersheds consists of rock, which has lower seepage rates and higher runoff than predominantly soil-covered watersheds.
- Lake Winnipeg, Cedar Lake and Southern Indian Lake serve as large storage reservoirs. The Utility's water storage capacity is a competitive advantage in trading electricity (buying surplus U.S. power at low off-peak prices and selling its electricity during peak demand periods at higher prices).

In addition to its own generating stations in Manitoba, Manitoba Hydro purchases all electricity from two wind farms in southern Manitoba (St. Joseph and St. Leon). The installed capacity of these facilities is 258.5 MW. The Wuskwatim Generating Station is owned by the Wuskwatim Power Limited Partnership, in which Manitoba Hydro is the majority owner. Manitoba Hydro purchases all the electricity generated from the Wuskwatim Generating Station.

## Generating Capacity

### Manitoba Hydro's Generating Stations and Capabilities

For the year ended March 31, 2016

Power Station	Location	# of Units	Net Capacity (MW)
<b>Hydroelectric</b>			
Great Falls	Winnipeg River	6	129
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	84
McArthur Falls	Winnipeg River	8	56
Pointe du Bois	Winnipeg River	16	75
Slave Falls	Winnipeg River	8	68
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	286
Kettle	Nelson River	12	1,220
Jenpeg	Nelson River	6	115
Long Spruce	Nelson River	10	980
Limestone	Nelson River	10	1,350
Laurie River (2)	Laurie River	3	10
Wuskwatim	Burntwood River	3	211
<b>Total Hydroelectric Generation</b>		<b>105</b>	<b>5,228</b>
<b>Thermal</b>			
Brandon (coal: 93 MW, gas: 234 MW)		3	327
Selkirk (gas)		2	125
<b>Total Thermal Generation</b>		<b>5</b>	<b>452</b>
<b>Isolated Diesel Capabilities</b>			
Brochet			3
Lac Brochet			2
Shamattawa			3
Tadoule Lake			2
<b>Total Isolated Diesel Generation</b>			<b>10</b>
<b>Total Generation Capacity</b>			<b>5,690</b>

Source: Manitoba Hydro

### The Manitoba Hydro-Electric Board <sup>1</sup>

#### Balance Sheet

(CAD millions)	March 31		
	<u>2016</u>	<u>2015</u>	<u>2014</u>
<b>Assets</b>			
Cash & equivalents	953	487	142
Accounts receivable	372	427	520
Inventories	117	99	81
Prepaid expenses & other	43	54	0
<b>Total Current Assets</b>	<b>1,485</b>	<b>1,067</b>	<b>743</b>
Net fixed assets	17,208	15,222	13,627
Goodwill & intangibles	301	290	281
Investments & others	786	988	988
<b>Total Assets</b>	<b>19,780</b>	<b>17,567</b>	<b>15,639</b>

#### Liabilities & Equity

	March 31		
	<u>2016</u>	<u>2015</u>	<u>2014</u>
S.T. borrowings	0	0	0
Accounts payable	723	529	561
Current portion L.T.D.	326	377	408
Other current liab.	192	190	100
<b>Total Current Liab.</b>	<b>1,241</b>	<b>1,096</b>	<b>1,069</b>
Long-term debt (net sinking fund investments)	14,201	12,189	10,349
Sinking fund investments	0	114	111
Other L.T. liab.	2,146	1,989	1,225
Shareholders' equity	2,192	2,179	2,885
<b>Total Liab. &amp; SE</b>	<b>19,780</b>	<b>17,567</b>	<b>15,639</b>

<sup>1</sup> 2015 to 2016 based on IFRS; 2014 based on Canadian GAAP.

#### Balance Sheet & Liquidity & Capital Ratios

For the year ended March 31 <sup>1</sup>

	<u>2016</u>	<u>2015</u>	<u>2014</u>	<u>2013</u>	<u>2012</u>
Current ratio	1.20	0.97	0.70	0.48	0.65
Total debt in capital structure	86.9%	85.2%	78.9%	76.6%	75.8%
Total debt in capital structure <sup>2</sup>	83.0%	81.3%	79.4%	78.5%	77.9%
Cash flow/Total debt	5.4%	5.3%	6.4%	6.1%	6.3%
(Cash flow-dividends)/Capex	0.35	0.38	0.50	0.57	0.50
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

#### Coverage Ratios (times)

EBIT gross interest coverage	0.91	1.07	0.96	0.89	0.80
EBITDA gross interest coverage	1.50	1.70	1.63	1.56	1.43
Fixed-charge coverage	0.91	1.07	0.96	0.89	0.80

#### Profitability Ratios

Purchased power/Electricity revenues	6.5%	7.1%	8.6%	7.7%	9.3%
Operating margin	30.3%	31.5%	30.9%	30.2%	28.4%
Net margin	2.8%	7.3%	8.8%	4.9%	3.6%
Return on equity <sup>2</sup>	1.9%	5.0%	6.6%	3.5%	2.4%

<sup>1</sup> 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. <sup>2</sup> Adjusted for other comprehensive income.

## Rating History

	Current	2015	2014	2013	2012	2011
Long-Term Obligations	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Short-Term Obligations	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Note: These Obligations are based on the status of the Manitoba Hydro-Electric Board as a Crown agent of the Province of Manitoba and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt, and thus reflect the Province's debt ratings.

## Previous Action

- Confirmed, September 12, 2016.

## Related Research

- *DBRS Confirms Province of Manitoba at A (high) and R-1 (middle)*, September 12, 2016.
- *Manitoba, Province of: Rating Report*, September 12, 2016.

## Short-Term Promissory Notes Programme

- \$500 million.

## Previous Report

- Manitoba Hydro-Electric Board, The: Rating Report, November 26, 2015.

### Notes:

All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on [www.dbrs.com](http://www.dbrs.com).

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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**TAB 8**

# Commercial Evaluation of Manitoba Hydro Preferred Development Plan Business Case

Prepared by Morrison Park Advisors  
For

**Manitoba Public Utilities Board**

**January 2014**

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# 1 **Executive Summary**

## 2 **Scope of Work**

3 MPA was retained by the PUB to provide a commercial evaluation of the Manitoba Hydro Preferred  
4 Development Plan Business Case, as detailed in the NFAT. Specifically, MPA's review is to include

5 a) Consideration of the overall costs, risks and benefits being assumed by Manitoba Hydro in the  
6 pursuit of the Preferred Development Plan, particularly in light of potential alternatives to the  
7 Preferred Development Plan which could satisfy provincial and ratepayer objectives (commercial  
8 reasonableness of the Preferred Development Plan);

9 b) Consideration of the costs assumed, risks taken, and compensating benefits expected for each  
10 relevant stakeholder of Manitoba Hydro, including ratepayers, the Government of Manitoba,  
11 Manitoba taxpayers, and others (relative commercial reasonableness of the Preferred  
12 Development Plan for various stakeholders);

13 c) Consideration of commercial risks being assumed by Manitoba Hydro as part of its export  
14 agreements, and specifically how these risks relate to the risks being taken by Manitoba  
15 ratepayers in the event that export agreements do not perform according to optimal scenarios  
16 (commercial reasonableness of the export aspects of the Preferred Development Plan in relation  
17 to the domestic services portions); and

18 d) Consideration of specific financial impacts and risks being assumed as part of the Preferred  
19 Development Plan by the Government of Manitoba and the taxpayers of Manitoba, as they  
20 relate to the Province's credit rating, borrowing capacity, potential impact on other budgetary  
21 priorities, credit availability, and credit rates in the future.

## 22 **Summary of Financial Model**

23 MPA has constructed a financial model on Manitoba Hydro's electrical operations in order to address  
24 the scope of work put to MPA by the PUB under the NFAT. MPA relied upon the NFAT Business Case,  
25 the appendices thereto, and numerous discussions and correspondence with Manitoba Hydro  
26 management and employees on the matter of Manitoba Hydro operations, and economic and financial  
27 conditions. MPA received SPLASH (Simulation Program for Long-term Analysis of System Hydraulics)  
28 output from Manitoba Hydro with respect to the development plans considered under the NFAT.

29 MPA matched the SPLASH data with the development plans detailed in Appendix 11.4 of the NFAT  
30 Business Case, eliminating plans for which pro forma financial statement data was not provided. MPA  
31 extracted chained, opportunity export revenue for every given hydrological regime and model year,  
32 allowing for the determination of actual, annual opportunity export revenue, calculated for a given  
33 supply mix that Manitoba Hydro anticipates to eventuate in a given year. This information and  
34 extraction (from SPLASH), and application (to Appendix 11.4) allowed MPA to produce a set of financial



1 statements (income statement, balance sheet and cash flow statement) for every development plan  
2 modelled under Appendix 11.4 under all scenarios, and under all previous hydrology regimes.

3 In reaching our conclusions contained in this report, MPA has run the All Gas and Preferred  
4 Development plans, and Plans 4, 6 and 12 under the 2012 reference Manitoba load for all 99 years of  
5 hydrological history through year 2062 (at reference economics, energy and capital, for 495 total runs).

6 The All Gas and Preferred Development Plans were further run at high and low 2012 Manitoba load for  
7 all 99 years of hydrological history through year 2062 (at reference economics, energy and capital, for  
8 396 total runs).

9 The Preferred Development Plan was further run at 4x 2013 DSM and 1x 2012 DSM (both at 2013  
10 reference Manitoba load) for all 99 years of hydrological history through year 2062 (at reference  
11 economics, energy and capital, for 198 total runs).

12 The All Gas and Preferred Development plans, and Plans 4,6 and 12, were run for 21 different years of  
13 hydrological history, for every combination of reference, high and low economics, energy and capital  
14 costs, for a total of 546 runs per development plan, or 2730 total runs.

15 In total, MPA performed 3,819 different runs of the financial model. The financial model, as constructed  
16 in the manner detailed above, formed the basis for our financial conclusions reached in this report.

### 17 **Findings on Ratepayer Total Costs**

- 18 • Findings are in reference to the average probability weighted present value basis of domestic  
19 revenue
- 20 • Resource Plans 4 and 6, which include Keeyask, some level of transmission interconnection and  
21 natural gas plants, appear to fare consistently better than the other options
- 22 • Plans 14 and 12, which include Conawapa, are consistently ranked as more costly to ratepayers  
23 than Plans 4 and 6, which include Keeyask but not Conawapa
- 24 • Plan 1, the All Gas Plan, ranks poorly when economic variables such as inflation and interest  
25 rates are low, but better when they are moderate or high; this is particularly true with respect to  
26 the Preferred Plan 14, which is superior to All Gas in the low economics environment but not  
27 otherwise
- 28 • Plan 1, the All Gas Plan, ranks relatively poorly when the discount rate is lower at 6%, but better  
29 when the discount rate is higher at 10%, suggesting that the relative time value of money is an  
30 important consideration
- 31 • Plan 4, with a 250 MW interconnection, always ranks better than Plan 6, with a 750 MW  
32 interconnection

- 1       • Similarly, Plan 14 is better than Plan 12 in every case but one, suggesting that an earlier  
2       construction and export orientation for the Conawapa facility is better than a later one
- 3       • Changing Manitoba demand does not actually affect the total cost to ratepayers over 48 years  
4       very much, if all other variables are kept constant; the difference in total cost to ratepayers  
5       between High and Low Manitoba demand futures is not more than about 2% in any of the cases

## 6 Findings on Government Revenues

7 As might be expected, the differences between Resource Plans with respect to revenues for the  
8 Government of Manitoba are clear, and align with the construction of hydroelectric facilities.

<b>Average Probability Weighted PV of Revenue to the Province of Manitoba</b>					
High, Ref and Low Economics, Energy and Capital (2015-2062) (\$ in millions)					
Revenue	Development Plan				
	1	4	6	12	14
NPV @ 6.00%					
Water Rentals	\$1,702	\$1,883	\$1,879	\$2,034	\$2,091
Provincial Debt Guarantee	\$2,614	\$3,031	\$3,075	\$3,561	\$3,783
Capital Taxes	\$1,584	\$1,874	\$1,883	\$2,229	\$2,275

9

10 In the Preferred Development Plan (14), Conawapa is built and built soonest, and hence water rental  
11 fees are greater, more debt must be guaranteed, and capital taxes are highest.

12 The differences between Plans (14) and (12), where Conawapa is built a few years later, are very  
13 modest. Similarly, the differences between Plans (4) and (6), which both include Keeyask but not  
14 Conawapa, are very minor, but these totals are noticeably lower than the Conawapa-based Resource  
15 Plans.

## 16 Findings on Export Orientation

17 As might be expected, the Preferred Development Plan (14), which includes the building of Conawapa  
18 earlier in time with the intention of signing long-term export contracts, includes the highest export  
19 revenues as a percentage of total Manitoba Hydro revenues.

**Average Export Revenue as a Percentage of Total Revenue  
All Gas and Preferred Development Plan**

Reference Economics and Capital  
(2015 - 2062)

Energy Scenario	Development Plan	
	1	14
Reference	9.5%	20.9%
High	11.9%	26.2%
Low	6.4%	14.3%

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- Resource Plans which have a higher reliance on export revenues are more sensitive to changes in export prices; this is borne out by reference to the model results if all variables except energy prices are kept constant: for example, average present value costs to ratepayers in Preferred Plan (14) are 10% lower if export prices are higher; whereas in All Gas Plan (1) there is little difference between the total ratepayer costs between scenarios with High and Low export prices
  - For government, higher exports mean that more of its revenue from Manitoba Hydro is actually coming from export jurisdictions, rather than ratepayers, which means that, *other things being equal*, the province as a whole should be receiving a net benefit

11 **Findings on Hydrology**

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- Hydrology is critical to short-term issues, such as the potential for financial distress, but is less relevant to longer term issues such as the present value of ratepayer costs over a 48-year period or longer
  - Though hydrology is less critical over longer terms, it does not mean that it is not relevant: even over a 35-year period the standard deviation of water flow is almost 5% of the historical average
  - Resource plans heavy in hydroelectric investment, such as the Preferred Development Plan (14), are more sensitive to hydrology, and will therefore demonstrate greater variation in all financial results (including Manitoba ratepayer costs), especially in the short term but also over the longer term, other things being equal

21 **Findings on Financial Distress**

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- Despite the fact that the most severe situations of financial distress caused by drought overwhelm distinctions between Resource Plans, there are useful distinctions that can be made
  - These include sensitivity to hydrology, sensitivity to the timing of distress, and overall financial strength
  - Some Resource Plans are more sensitive to hydrology than others

- 1 • It is inescapable that the net income of Manitoba Hydro will be more sensitive to hydrology if  
2 Keyask, Conawapa or both are built
- 3 • It should be noted that this sensitivity goes both ways: these Resource Plans will be exposed to  
4 higher highs and lower lows in net income and other financial indicators based on the future  
5 course of hydrology
- 6 • Timing is extremely relevant, and there are distinctions between the resource plans

## 7 **Conclusions**

8 Analysis of the available data and construction of a financial model capable of incorporating hydrology  
9 has allowed for the illumination of a number of patterns, and a variety of observations that will, it is  
10 hoped, assist the PUB in making its recommendations to government on the NFAT Review of the  
11 Manitoba Hydro Preferred Development Plan.

12 Key observations have included:

- 13 • The ability of Manitoba Hydro to meet its financial targets over the next ten years without  
14 increasing rates beyond two times the rate of inflation – under all Resource Plans – is entirely  
15 dependent on the continued absence of a significant drought
- 16 • Different Resource Plans extend that period of fragility, including the Preferred Development  
17 Plan, which should not be expected to enter a time of more financial capacity for 20 years,  
18 unless rates are allowed to rise at more than double the rate of inflation for an extended period  
19 of time
- 20 • In the face of a sustained, severe drought, the choice of Resource Plan is irrelevant to the  
21 occurrence of distress, as the financial consequences of such a drought would overwhelm the  
22 differences between Resource Plans
- 23 • Choice of Resource Plan does affect the occurrence of financial distress due to drought in milder  
24 drought cases, and it also affects the magnitude of the problem that would be faced by  
25 government in the event of a drought of any kind
- 26 • The total, probability-adjusted present value of ratepayer costs over 48 years across all five  
27 Resource Plans is likely too narrowly distributed to allow for definitive selection of the “lowest  
28 cost” choice. These outcomes are essentially within the margin of error of the many  
29 calculations, estimates and assumptions that were required to construct the model
- 30 • The consistent patterns of sensitivity of specific Resource Plans to certain variables indicates  
31 that model analysis can provide a guide to identifying the concerns that should be part of any  
32 decision-making process

- 1       • An extremely important inter-generational decision is embedded in the choice of Resource Plan,  
2       as costs to Ratepayers will be distributed very differently over time.

3       Bearing these and other observations in mind, we would suggest the following recommendations:

- 4       a) Plans 4 and 6, which were largely indistinguishable from each other, resulted in costs to  
5       ratepayers that appear to be lower than other Resource Plans in many scenarios, if only  
6       marginally; this suggests that proceeding with Keeyask may be a prudent step to take at this  
7       time, but a more thorough review of the proposal to build Conawapa as part of the Preferred  
8       Development Plan should be undertaken closer to its final commitment date
- 9       b) Given the expected fragility of Manitoba Hydro during the first ten years of any Resource Plan,  
10      and beyond that in others, the Government of Manitoba may wish to calculate and reserve  
11      some of the funds it generates (e.g., through permits, approvals, income taxes, etc., related to  
12      the construction projects) to act as an initial financial buffer for the government in the event of  
13      drought and the need for financial assistance to Manitoba Hydro
- 14      c) Given the inevitability of a drought at some point in the future, and the expected financial  
15      impact that such a drought would have on Manitoba Hydro, particularly in the near term,  
16      consideration should be given to the development of an explicit policy on the future course of  
17      customer rates in such a situation; this policy could then be shared with credit rating agencies  
18      and others to address the potential concern that they may have that in the event of a drought  
19      some fraction of Manitoba Hydro debt might be financially unsupported.

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## 1. Introduction

Morrison Park Advisors was retained by the Manitoba Public Utilities Board (hereinafter the “PUB”) to assist in the consideration of various commercial aspects of the “Needs For and Alternatives To” (hereinafter the “NFAT”) Review of Manitoba Hydro’s Preferred Development Plan (hereinafter the “Preferred Development Plan”).

### 1.1. Morrison Park Advisors

Morrison Park Advisors is an independent, partner-owned, Canadian investment bank providing financial advisory services to corporations and governments. MPA focuses on several industry sectors, including the regulated utility/energy infrastructure sector, in which it has substantial background and expertise. We provide independent expert advice to clients involved in regulatory processes; commercial litigation and arbitration; commercial and balance sheet restructuring events; debt and/or equity capital raising; and mergers, acquisitions and divestitures. Our ability to deliver top-tier financial advisory services is based on decades of combined experience and expertise developed at some of Canada’s leading investment banks, while serving many of Canada’s largest and most sophisticated corporate clients as well as federal, provincial and municipal governments and quasi-government entities.

Information on the MPA partners who participated in the preparation of this Report is available in Appendix A.

For more information on MPA, please visit our website at [www.morrisonpark.com](http://www.morrisonpark.com).

#### 1.1.1. Independence of MPA

MPA confirms that:

- a) neither MPA nor any of its affiliated entities is an associated entity or affiliated entity or insider of Manitoba Hydro or any of its affiliates;
- b) prior to the date hereof, MPA has not been engaged as financial advisor to Manitoba Hydro or any of its affiliates; and
- c) during the term of its engagement, MPA will not be engaged by Manitoba Hydro or its affiliates as a financial advisor in respect of the NFAT.

## 1           **1.2.       MPA’s Mandate and Scope of Work**

2   MPA was retained by the PUB to provide a commercial evaluation of the Manitoba Hydro Preferred  
3   Development Plan Business Case, as detailed in the NFAT. Specifically, MPA’s review is to include:

- 4           e) Consideration of the overall costs, risks and benefits being assumed by Manitoba Hydro in the  
5           pursuit of the Preferred Development Plan, particularly in light of potential alternatives to the  
6           Preferred Development Plan which could satisfy provincial and ratepayer objectives (commercial  
7           reasonableness of the Preferred Development Plan);
- 8           f) Consideration of the costs assumed, risks taken, and compensating benefits expected for each  
9           relevant stakeholder of Manitoba Hydro, including ratepayers, the Government of Manitoba,  
10          Manitoba taxpayers, and others (relative commercial reasonableness of the Preferred  
11          Development Plan for various stakeholders);
- 12          g) Consideration of commercial risks being assumed by Manitoba Hydro as part of its export  
13          agreements, and specifically how these risks relate to the risks being taken by Manitoba  
14          ratepayers in the event that export agreements do not perform according to optimal scenarios  
15          (commercial reasonableness of the export aspects of the Preferred Development Plan in relation  
16          to the domestic services portions); and
- 17          h) Consideration of specific financial impacts and risks being assumed as part of the Preferred  
18          Development Plan by the Government of Manitoba and the taxpayers of Manitoba, as they  
19          relate to the Province’s credit rating, borrowing capacity, potential impact on other budgetary  
20          priorities, credit availability, and credit rates in the future.

## 21           **1.3.       Report Structure**

22   The Business Case and supporting evidence presented by Manitoba Hydro in favour of the Preferred  
23   Development Plan is extremely detailed (the initial filing ran to approximately 5,000 pages, and  
24   responses to Information Requests have been similarly voluminous). We have attempted to condense  
25   many concepts in a relatively brief narrative in order to highlight critical issues that we believe should be  
26   considered by the PUB. In addition to the sections of this Report described below, we have provided  
27   Appendices which provide greater detail on certain matters which, while important, would distract from  
28   the narrative and its core issues.

29

1

**Table 1. Report Structure**

Section	Title	Matters Addressed
2	Context	<ul style="list-style-type: none"> <li>Manitoba Electricity System</li> <li>Stakeholders and Their Interests</li> <li>Risks Relevant to Electricity Resource Planning</li> </ul>
3	Resource Alternatives	<ul style="list-style-type: none"> <li>Features of Plans</li> <li>Variables that Should be Considered</li> </ul>
4	Financial Modeling	<ul style="list-style-type: none"> <li>Approach Taken</li> <li>Findings</li> </ul>
5	Specific Issues	<ul style="list-style-type: none"> <li>Weighted Average Cost of Capital and Discount Rate</li> <li>Exports</li> <li>Potential Impact on Province of Manitoba</li> </ul>
6	Costs, Risks and Benefits	<ul style="list-style-type: none"> <li>Ratepayers</li> <li>Government of Manitoba</li> <li>Relative Distribution Issues</li> </ul>
7	Recommendations and Conclusions	<ul style="list-style-type: none"> <li>Report recommendations and conclusions</li> </ul>

2

3

## 1.4. Note on the Use of Projections and Models

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In preparing our Report, we have made use of the following:

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a) Information that was made available by Manitoba Hydro through this regulatory process, inclusive of the NFAT Business Case and supporting evidence admitted, responses to all information requests, and direct discussions that were organized by the PUB for Independent Expert Consultants;

9

10

11

b) Information that was publicly available, whether from Manitoba Hydro, the Government of Manitoba, from public authorities such as electricity system and market operators in other jurisdictions, or from general corporate, economic and financial sources;

12

c) Financial information available through paid subscription services;

13

14

d) Information, advice and opinions of other Independent Expert Consultants participating in this regulatory process on behalf of the PUB, in the form of discussions, meetings and reports;

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e) Our general experience, qualifications and skills in financial analysis and the preparation of valuations and opinions on fairness from a financial point of view.

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A very significant component of the work of this Report involved the use of forecasts, projections and estimates, and in particular those provided by Manitoba Hydro in evidence and in response to information requests. We have not passed any judgment on the validity or reliability of these projections and estimates (except in select cases specifically addressed below), but rather have assumed



1 that they were prepared with all due care based on the professional qualifications of those responsible  
2 for them.

3 It is critical to point out, however, the fundamental uncertainty that underlies many of the projections in  
4 question, particularly as they extend out not only years, but decades. Useful forecasts for the near to  
5 medium term are typically based on the belief – sometimes proven by subsequent events to be  
6 erroneous – that the future will consist of incremental changes to the practices of the past. However,  
7 the longer the time horizon of the forecast, the more likely that changes will cease to be incremental,  
8 and become truly unpredictable. What may appear to be reasonable today may at some point in the  
9 future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck. Prices  
10 change, technology changes, market dynamics change, the relative cost of goods changes: all in  
11 unpredictable ways over time.

12 Technological advances, in particular, can render assumptions obsolete even in relatively short periods  
13 of time. The development of hydraulic fracturing in the natural gas industry over the past decade is only  
14 a recent example of expectations about future market conditions being totally undermined: widespread  
15 expectations a decade ago were that North America would by now be supply constrained and  
16 increasingly reliant on expensive imports of natural gas from elsewhere, yet now there is a rush to find  
17 ways to export an overabundant commodity that has dropped dramatically in price. In earlier decades  
18 similar received wisdom was overturned (for example, there was a time in the mid-twentieth century  
19 when many experts believed that nuclear power would render electricity “too cheap to meter”.<sup>1</sup>  
20 Needless to say, the aspiration was never achieved).

21 There is a significant danger in assuming that a view of the future from the perspective of today will be  
22 very accurate. All such assumptions should be approached with humility, and treated with respect as the  
23 best available basis for decision-making, but without claiming them to be more than what they are.  
24 Decisions cannot be made without taking a view of the future, but the future may prove unwilling to  
25 agree with the forecasts made of it.

26 It is commonplace that commercial transactions are analyzed using mathematical models, often  
27 providing a degree of precision measured in decimal points, which sometimes gives the illusion of  
28 accuracy or predictive power. We have used such models in the preparation of this Report. However,  
29 these models are only as accurate as the assumptions about the future that underlie them. Since those  
30 assumptions must be given a broad range because of the difficulty inherent in predicting the future,  
31 especially over decades, the models should and do result in outputs with an equally broad range. This  
32 means that mathematical models sometimes may be capable of excluding certain decision options from  
33 the realm of reasonable commercial choice, but cannot always point to a single preferred outcome  
34 among several. In these cases, decisions still must be made, but they must be rendered on the basis of  
35 judgement.

36 Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify.

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<sup>1</sup> The phrase was coined by Lewis L. Strauss, Chairman of the United States Atomic Energy Commission in a 1954 Speech to the National Association of Science Writers.

## 1 2. Context

2 The Preferred Development Plan is a long-term resource plan for electricity in the Province of Manitoba.  
3 Analyzing its features requires an understanding of the electricity system in the Province, and its  
4 expected needs.

### 5 2.1. Manitoba Hydro

6 Manitoba Hydro is the sole utility provider of electricity in the province, and is a Crown Corporation with  
7 the mandate<sup>2</sup> to:

- 8 • Provide electricity to Manitoba ratepayers as economically as possible, consistent with a safe  
9 and reliable system; and
- 10 • Exploit opportunities to export electricity and electricity-related services to the benefit of the  
11 Province of Manitoba and its ratepayers.

12 As a Crown Corporation, Manitoba Hydro does not pay dividends to the province of Manitoba (the  
13 “shareholder”),<sup>3</sup> nor does it pay income tax. Notwithstanding the organization of the entity on corporate  
14 lines – with debt and “equity” on its balance sheet – it is not a profit-maximizing enterprise. By  
15 legislation, it is entitled only to seek revenues sufficient to satisfy its operating costs, debt servicing  
16 needs, and to maintain reserves for various purposes, including the management of contingencies and  
17 smoothing of rates over time.<sup>4</sup> The corporation’s “equity” is better understood as a form of reserve  
18 fund, and its “profits” in any given year as a contribution to that reserve.

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<sup>2</sup> The *Manitoba Hydro Act* describes the objects and purposes as follows:

2. The purposes and objects of this *Act* are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are
  - (a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and
  - (b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.

The *Terms of Reference* of the Manitoba Hydro Electric Board specify the following:

The corporation is charged with responsibilities which include, to ensure a safe, reliable, economical and environmentally responsible supply of energy for Manitoba, and to earn revenues to keep rates low for Manitobans through the export of power and the provision of energy-related services.

<sup>3</sup> Note that in fiscal year 2002-3, the Government of Manitoba received a special dividend payment of \$203 million. This payment was specifically required by amendment of the *Manitoba Hydro Act*. See Statutes of Manitoba, c. 41.

<sup>4</sup> Please see *Manitoba Hydro Act*, s. 39(1) and s. 40(1).

1 By agreement with the shareholder, the target level of “equity” in the corporation is 25% of total  
2 capital,<sup>5</sup> as defined by the following formula:

3 **Formula 1. Equity Ratio Calculation**

$$\frac{\text{Total Equity} = \left\{ \begin{array}{l} \text{Retained Earnings} + \text{Contributions in aid} + \text{Accumulated Other} + \text{Non-controlling} \\ \text{of Construction} + \text{Comprehensive Income} + \text{Interest} \end{array} \right\}}{\text{(Long-term Debt – Sinking Funds – Cash) + Total Equity}} = 25\%$$

4

5 However, this is a long-term target, which serves as a financial guideline only, not an annual  
6 requirement. As a result, the equity ratio floats over time, depending upon actual financial results in any  
7 given year, the capital investment program being pursued at the time, and the rates set by the PUB. For  
8 example, the equity ratio for the past ten years has been reported as follows:

9 **Table 2. Equity Ratio Performance**

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
13%	15%	19%	20%	27%	23%	27%	27%	26%	25%

10

Source: Manitoba Hydro, *62nd Annual Report*, year ending March 31, 2013

11 In addition to the equity target, Manitoba Hydro also attempts to meet two other measures of financial  
12 health, which are to ensure that its Interest Coverage Ratio (“ICR”) is above 1.2, and that typical capital  
13 needs (not including major investments such as generation facilities) can be funded through internal  
14 resources.<sup>6</sup> The formula in use for ICR is:

15 **Formula 2. Interest Coverage Ratio Calculation**

$$\frac{\text{Net Income} + \text{Interest Payments on Debt}}{\text{Interest Payments on Debt}} = \text{ICR}$$

16

17 In essence, targeting a minimum ICR of 1.2 means that Manitoba Hydro will organize its affairs – and  
18 seek rates from the PUB – consistent with maintaining a 20% cushion of annual cash availability over  
19 and above its expected costs of interest.

20

<sup>5</sup> The 75:25 target ratio was first established in September 1995 by the Manitoba Hydro Electric Board. Please see the response to Information Request MPA/MH I-011a.

<sup>6</sup> The Capital Target is 1.2 times typical capital needs, not including major generation or transmission projects, according to the most recent Debt Management Strategy, April 2012, filed with the PUB as part of the General Rate Application.

1  
2 Over the past ten years, the company's performance on this measure has been as follows:

3 **Table 3. Interest Coverage Ratio Performance**

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
0.17	1.25	1.77	1.23	1.69	1.49	1.32	1.27	1.10	1.15

4 Source: 62<sup>nd</sup> Annual Report

5 The notably low performance in 2003-04 coincided with a drought that year, which dramatically affected  
6 the company's net income, in fact resulting in losses for that year (since net income was negative, the  
7 resulting ICR for the year was below 1.0; ICR can actually be negative itself, if losses in a year are greater  
8 than interest payments).

9 Manitoba Hydro has two sources of capital: internally generated cash flow, and debt. Long-term debt  
10 resources are provided by advances from the Government of Manitoba.<sup>7</sup> The Government of Manitoba  
11 raises debt from Canadian and international capital markets in the amounts and with the terms and  
12 conditions agreed upon with Manitoba Hydro, and then provides that debt on a back-to-back basis, with  
13 the addition of a "debt guarantee fee", currently equal to an annual payment of 1% per year on all  
14 outstanding long-term debt. Given that the debt is raised by the Government of Manitoba directly on its  
15 own account, and then subsequently advanced by the Government to Manitoba Hydro, the Government  
16 and taxpayers of Manitoba are directly liable for the full amount of the debt, regardless of the ability of  
17 Manitoba Hydro to make good on its annual interest and principal payments to the Government.

18 Crucially, notwithstanding the fact that the Government of Manitoba raises the required long-term debt  
19 for Manitoba Hydro, and on its face this debt is debt of the Province, credit rating agencies and the  
20 capital markets do not in practice treat that debt as debt of the province, but rather as debt supported  
21 by Manitoba Hydro and its ratepayers.<sup>8</sup> This is a very important element in the calculation of the  
22 Province's credit-worthiness, and hence the overall credit rating on provincial debt. This issue will be  
23 addressed further below, in section 4 (financial distress).

## 24 **2.2. Manitoba's Electricity System Resources**

25 Virtually all electricity users in Manitoba are connected to Manitoba Hydro's electricity system.<sup>9</sup>  
26 Manitoba Hydro currently serves approximately 550,000 customers, and does so with a generation  
27 system amounting to over 5,500 MW peak capacity. More than 90% of the generation resources are

<sup>7</sup> Manitoba Hydro issues a small amount of debt on its own account through Manitoba Hydro bonds, however the vast majority of debt is through Government of Manitoba advances. As per the March 31, 2013 Annual Report, Government advances amounted to \$9,775 million out of total long-term debt of \$10,012 million.

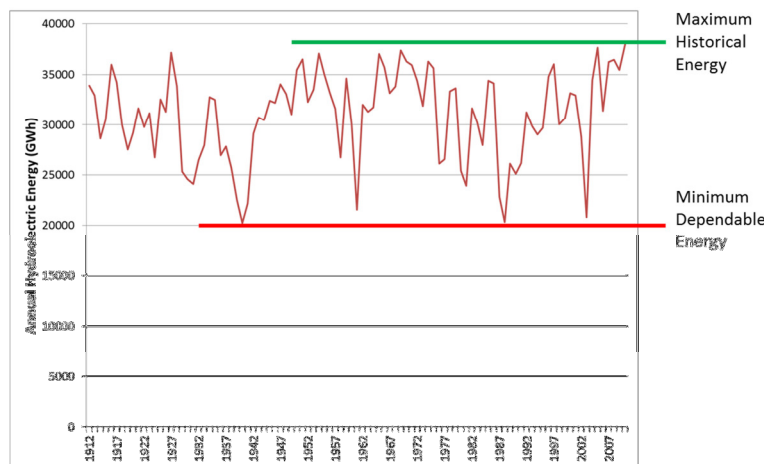
<sup>8</sup> See for example *Credit Analysis of Province of Manitoba*, Moody's Investor Service, July 23, 2013, p. 3: "Roughly one third of the province's total direct and indirect debt is attributed to Manitoba Hydro (issued and on-lent by the province) and is considered to be self-supporting."

<sup>9</sup> A small number of remotely located customers are served through standalone diesel generators.

1 water powered, which puts Manitoba into a select group of “hydro” jurisdictions, which includes  
 2 Quebec, British Columbia, Newfoundland & Labrador, Norway, Paraguay, and Iceland.<sup>10</sup>

3 Like all other predominately water powered systems, Manitoba Hydro must manage the reality of ever-  
 4 changing annual precipitation. In any given year, water flow through hydroelectric generation facilities  
 5 can be much higher or much lower, resulting in very different levels of annual energy production. As  
 6 Figure 5.8 from the NFAT Business Case makes clear, the lowest water flow of the past 100 years was  
 7 only 47% of average, while the highest year was 168% of average.<sup>11</sup> That is a range of more than 3.5  
 8 times the water flow from lowest year to highest year on record. Yet for reasons of reliability, it is only  
 9 safe to count on the lowest levels as “dependable” energy. If Manitoba’s current hydroelectric facilities  
 10 had been in place over the past 100 years, it might have had the following annual performance (note  
 11 that this is an illustration only, based on a certain set assumptions about reservoirs, water management,  
 12 transmission facilities, etc.).

13 **Figure 1. Illustration of Hydroelectric Performance**



14  
 15 If the system included no other electricity resources, then it would be necessary to ensure that the  
 16 minimum dependable energy level was sufficient to satisfy all domestic needs. If Manitoba demand  
 17 were expected to grow in the foreseeable future to the point that demand would exceed minimum  
 18 dependable energy, then more hydroelectric generation capacity would be required.

19 In most years, however, the system will produce more (and in some years much, much more) than the  
 20 minimum level of energy. Since demand is fairly stable on a short-term basis, all of the excess energy in  
 21 any given year may be exported to neighbouring jurisdictions, or if possible “saved” by filling up water  
 22 reservoirs and not producing the energy in the first place.<sup>12</sup> To the extent that existing facilities can

<sup>10</sup> Iceland’s electricity system is approximately 75% hydro, and 25% geothermal, which is also renewable and relatively inexpensive. Newfoundland & Labrador is currently building a new hydroelectric generation facility – Muskrat Falls – which, once built, will allow for the closure of the Holyrood oil-fired station, and which will result in the province having an electricity system which is 100% supported by wind and water powered generation.

<sup>11</sup> Data from Figure 5.8 provided by Manitoba Hydro in response to Information Request MPA/MH II-021.

<sup>12</sup> In the event that reservoirs are full, and exports have reached the maximum possible based on transmission line capacity, then remaining water will be spilled over dams and not run through generators.

1 produce more dependable energy than is needed domestically, then that “extra” dependable energy  
2 can be exported through firm contracts to other jurisdictions.

3 In the case of Manitoba today, the Province is not solely dependent on water power: the electricity  
4 system includes two thermal energy facilities (one coal unit, and four natural gas units), two wind power  
5 facilities (wind power suffers good and bad years like water power, but generally is not as variable, and  
6 on its own schedule, not correlated to water flow), and the ability to import electricity from other  
7 jurisdictions. All of this means that total dependable energy is somewhat higher than what can be relied  
8 on from Manitoba Hydro’s hydroelectric generation facilities.

9 In order for thermal plants to be maintained in good working order and available when needed, they  
10 have to be operated for a small percentage of any week, regardless of whether there is sufficient water  
11 power to meet needs. It is the nature of wind turbines that they produce energy whether needed for  
12 system purposes or not, so they also increase by a small amount the system’s total output every year.  
13 Imports, however, need only be purchased when they are needed. The combination of these factors  
14 means that total system energy output is always greater than annual water power output, and in years  
15 where water is extremely low, other resources ensure that the system’s minimum total energy is  
16 delivered.

17 Currently, Manitoba’s electricity system has the following output characteristics:

18 **Table 4. Manitoba System Resources**

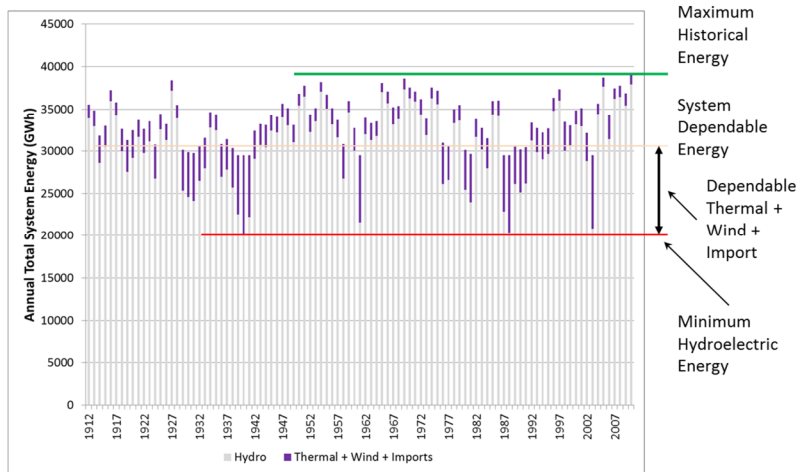
<b>System Dependable Energy</b>	<b>Energy (GWh)</b>
Minimum Dependable Water Power	21,950
Dependable Energy from Thermal, Wind & Imports	8,303
<b>Total System Dependable Energy</b>	30,253
Maximum Water Power Potential	38,000 (approx.)

19 Source: NFAT Business Case, Appendix 4.2; IR MPA/MH II-022

20 The following chart depicts how Manitoba’s current electricity system would have performed if it had  
21 been in place over the past hundred years, assuming that demand in every year was equivalent to  
22 today:

1

**Figure 2. Illustration of Manitoba Electricity System**



2

3 In addition to measuring the total annual energy production of the Manitoba electricity system, it is also  
 4 important to note the peak system capacity: the amount of power that the system can supply at any  
 5 given moment to all of its customers. Because Manitoba’s hydroelectric facilities are supported by a  
 6 system of reservoirs and water control structures, they can be managed so that they operate at higher  
 7 power output levels at certain times of the day or year, and at lower power output levels when less  
 8 electricity is likely to be needed. In this way, even in years with less water flow the system can operate  
 9 at peak capacity at critical times. Thermal facilities can always generate their peak capacity (unless they  
 10 are out of service), and usually at short notice. Imports can only be relied upon if firm capacity contracts  
 11 are in place for expected peak periods of time. Fortunately for Manitoba, the province’s peak  
 12 requirements occur in the winter, while in neighbouring jurisdictions peak requirements occur in the  
 13 summer, so imports are generally available during Manitoba’s periods of peak need. Finally, wind power  
 14 is unreliable on an hourly basis, so it cannot be counted upon for peak capacity. Currently, Manitoba  
 15 Hydro’s system has the following peak capacity characteristics:

16

**Table 5. Manitoba Peak Capacities**

Total System Peak Capacity	Capacity (MW)
Hydroelectric Peak Capacity	5,177
Thermal	517
Contracted Imports	550
<b>Total System Peak Capacity</b>	<b>6,244</b>
2012-13 Manitoba Peak Demand	4,535 (approx.)

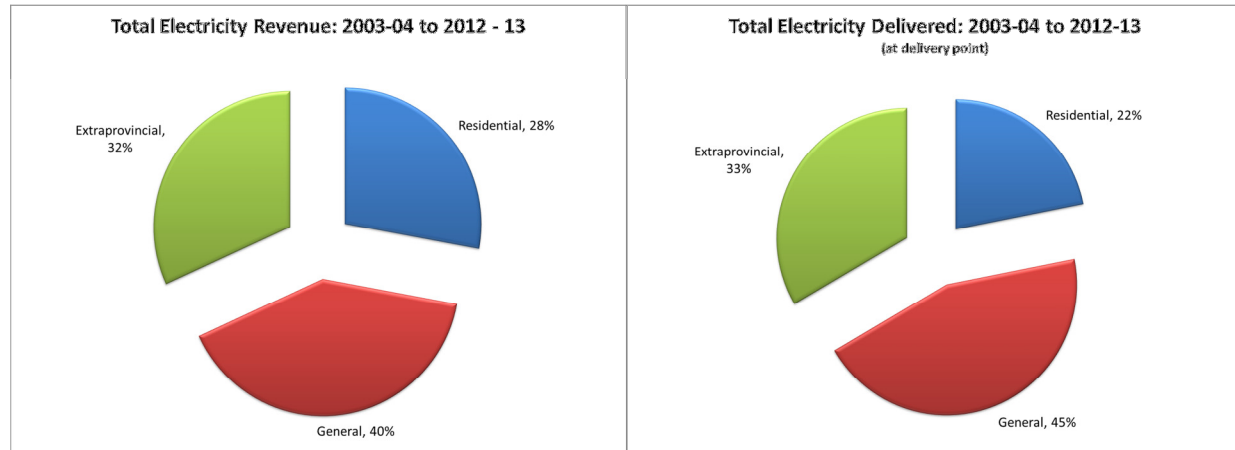
17

Source: NFAT Business Case, Appendix 4.2; 62<sup>nd</sup> Annual Report

18 Revenues for Manitoba Hydro consist of the sum total of domestic ratepayer charges, contracted export  
 19 revenues, and revenues from opportunity exports. Over the past ten fiscal years from 2003-04 to 2012-  
 20 13, export revenues have represented approximately 32% of total Manitoba Hydro revenues from

1 electric operations (not including “other” revenues from consulting, etc.).<sup>13</sup> Exports delivered at the  
2 Manitoba border equaled approximately 33% of total energy delivered to customers.

3 **Figure 3. Manitoba Hydro Electricity Revenues and Deliveries**



4  
5 Source: 62<sup>nd</sup> Annual Report

6 Since the relative domestic and extra-provincial proportions of revenues and delivered exports was  
7 about the same, this means that the price per unit of energy for Manitoba ratepayers (on average for all  
8 ratepayers over the ten-year period) was about equal to the price paid by export jurisdictions for power  
9 received from Manitoba. *However, it is crucial to note that for Manitoba ratepayers, this was the all-in*  
10 *price for power, whereas customers outside Manitoba had to pay transmission, distribution and other*  
11 *costs in addition to the price paid to Manitoba for the raw energy received.* The result is that Manitoba  
12 ratepayers had a total average cost of electricity – including generation, transmission, distribution and  
13 all other services - over that ten year period that was much lower than surrounding jurisdictions. This is  
14 consistent with the view that electricity costs in Manitoba are relatively very low.

15 Hydro-Quebec produces an annual survey of electricity costs in twenty-one different cities across North  
16 America. They compare the total cost of electricity, before taxes, for seven different customer profiles  
17 ranging from typical residential customers to the largest industrial consumers (customers are classed  
18 based on monthly energy consumption and monthly peak demand). Winnipeg, and by extension the rest  
19 of Manitoba, ranks among the three lowest cost jurisdictions included in the survey in every customer  
20 category.<sup>14</sup> This status as a low-cost electricity jurisdiction is a competitive advantage for the province.  
21 Critically, in the two categories for the very largest customers, Manitoba is the lowest cost jurisdiction  
22 surveyed, with a 5% cost advantage over the next jurisdiction for the largest customer class, and a 10%  
23 cost advantage over the next jurisdiction in the second largest customer class.

24

<sup>13</sup> 62<sup>nd</sup> Annual Report, for the year ended March 31, 2013, Manitoba Hydro, data from pages 98-99.

<sup>14</sup> Please see *Comparison of Electricity Prices in Major North American Cities, 2013*, by Hydro Quebec. Available online at [www.hydroquebec.com](http://www.hydroquebec.com).



## 1           **2.3.       New Resource Needs and Opportunities**

2       Manitoba Hydro has identified that existing electricity resources will no longer be sufficient to meet  
3       domestic needs sometime during the mid- to late-2020s. This is claimed for both annual energy  
4       production and peak capacity. Moreover, since Manitoba Hydro currently has ongoing contractual  
5       obligations for dependable exports, the need for additional resources will occur even earlier.

6       In Chapter 4 of the NFAT Business Case, Manitoba Hydro describes their Planning Criteria, the history  
7       and expectations of demand growth in Manitoba, the past and expected future success of demand-side  
8       management programs (“DSM”) to curb demand growth, and the resulting timing of the need for new  
9       resources.

10      Other experts retained by the PUB have examined closely the assumptions, methodologies and  
11      conclusions relied on by Manitoba Hydro to estimate the growth in domestic demand.<sup>15</sup> To the extent  
12      that there is doubt about the near-term expectations for Manitoba demand growth, or the ability of  
13      DSM programs to economically curb that growth, it is largely the timing of the need for new resources  
14      that would be affected. In the longer-term, however, the assumption that Manitoba demand will  
15      continue to increase relentlessly into the future is more controversial, and will be addressed further  
16      below in the discussion of risks in section 4.2.2 (Impact of Manitoba Demand).

17      In addition to growing Manitoba demand for electricity resources, Manitoba Hydro has identified new  
18      export opportunities. Several term sheets have been negotiated with counterparties interested in  
19      contracting with Manitoba for firm exports of electricity, if – but only if – Manitoba proceeds with new  
20      construction of hydroelectric generating stations.

21      The vast majority of Manitoba electricity exports are destined for utilities in the United States. Manitoba  
22      sells a small portion of its available exports to Ontario and Saskatchewan, but in the fiscal year 2012-13  
23      approximately 88% of its export revenues were from sales to the United States.<sup>16</sup>

24      The Midcontinent Independent System Operator (MISO) is the organization which operates the multi-  
25      utility electricity transmission grid into which Manitoba Hydro sells most of its exports. MISO has a peak  
26      summer generation capacity of over 100,000 MW, and is many times the size of Manitoba’s electricity  
27      system when measured by generation resources, customers and total energy consumption. Its resources  
28      are based largely on coal and natural gas-fired generation facilities, with a substantial and growing  
29      amount of wind power resources.<sup>17</sup> Given its reliance on coal and natural gas facilities which can run  
30      almost constantly when needed, the MISO market does not face any shortage of annual power output,  
31      but instead planning issues centre on the need to replace retiring coal capacity, and the need to reduce  
32      the carbon footprint of electricity output in the future.

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<sup>15</sup> Please see reports submitted to the PUB by Elenchus Research Associates Inc. on the load forecast and DSM.

<sup>16</sup> *62nd Annual Report*, p. 49.

<sup>17</sup> Please see, for example, *2012 State of the Market Report for the MISO Electricity Markets*, June 2013; available online at [www.misoenergy.org](http://www.misoenergy.org).

1 Given these characteristics, it is understandable why MISO utilities would only be interested in  
2 hydroelectric power from Manitoba: they have their own coal, natural gas and wind resources, and  
3 would have no economic need to import those from Manitoba Hydro (in fact, importing them would  
4 likely be uneconomic, because it would entail transmission costs to bring power across long distances).  
5 On the other hand, hydroelectric energy is carbon-free like wind, but if supplied in the form of a firm  
6 energy contract, would be much more reliable, and help them to meet their capacity needs while also  
7 reducing their system's carbon output.

8 Currently, when an export market buys power from Manitoba, it is 90%+ "carbon free", given  
9 Manitoba's generation mix. If Manitoba were to build new hydroelectric generation facilities, then its  
10 power would still be 90%+ carbon free (in fact, the figure would rise to 95%+). However, if Manitoba  
11 builds natural gas-fired facilities, or meets its needs in some other way, then it may no longer be able to  
12 claim that it meets that high standard of "carbon free" production. It is not unreasonable to believe, in  
13 these circumstances, that if Manitoba Hydro builds additional hydroelectric generation facilities, it  
14 would find willing buyers for firm energy contracts – at *some* price – for the sale of a substantial portion  
15 of the excess dependable energy that would be expected to be available post-construction.

## 16 **2.4. Stakeholders and Their Interests**

### 17 **2.4.1. Manitoba Ratepayers**

18 Manitoba Ratepayers benefit from Manitoba's electricity system, but are also obligated to pay all of  
19 Manitoba Hydro's costs, less whatever revenue can be earned from exports. Ratepayers are the primary  
20 stakeholder in Manitoba's electricity system, and hence in the consideration of Manitoba Hydro's  
21 Preferred Development Plan. Ratepayer interests are fairly straightforward to identify: they want safe,  
22 reliable electricity services at the lowest possible cost over time. In considering a forward-looking  
23 resource plan such as the Preferred Development Plan, however, it is not possible to specifically forecast  
24 future costs, because they depend on a great many variables that will only be known for certain in  
25 retrospect, as will be discussed much more extensively below. As a result, it is better to formulate  
26 ratepayer interests as: safe, reliable electricity services at the lowest possible *risk-adjusted* cost over  
27 time.

28 The notion of *time* also raises complications when considering ratepayers as a collective. Given that the  
29 Preferred Development Plan and its alternatives would play out over many decades, and that electricity  
30 costs over such a period would necessarily fluctuate, the costs and benefits of any alternative might be  
31 distributed differently between ratepayers over the next twenty years, for example, and ratepayers for  
32 the subsequent twenty year period, or the period after that. Inter-generational equity between  
33 ratepayers is therefore an issue which should be given consideration when reviewing Manitoba Hydro's  
34 options. This will be discussed further below, in section 4 (financial analysis).

35

## 2.4.2. Government of Manitoba

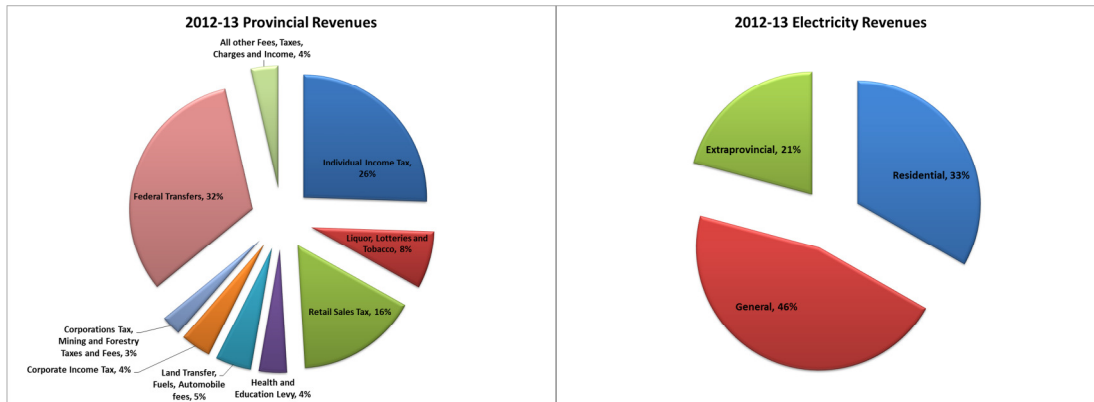
The Government of Manitoba, on behalf of the taxpayers and citizens of Manitoba, is the sole shareholder of Manitoba Hydro, and hence is also an obvious stakeholder in the decision to be made. The Government's interests, however, are more complex than for ratepayers, and include several priorities:

- *Ensure Competitive Electricity Rates:* As has already been noted, Manitoba currently benefits from very low electricity costs as compared to most jurisdictions in North America. This is clearly a competitive advantage for the province, as it may help attract industrial consumers of electricity to the province, who in turn are responsible for jobs and economic development. In addition, since electricity is part of the cost of doing business in every industry – to a greater or lesser degree – keeping electricity costs low generally makes Manitoba businesses more competitive than they would otherwise be. From the perspective of the Government of Manitoba, keeping rates competitive with other jurisdictions is therefore an important goal. However, it is not clear that it is necessarily important for Manitoba to attempt to *maximize* this goal: i.e., to be competitive with other jurisdictions, electricity costs do not need to be “as low as possible”, only lower than elsewhere. If rates in other low cost jurisdictions are rising – for example by the rate of inflation – then Manitoba does not harm its competitive position by allowing its rates to rise by a similar amount.
- *Maximize Tax Revenue, Fees and Charges Paid to Government:* Manitoba Hydro does not pay dividends or income tax to the Province, but it does provide several other revenue streams to government. Water “rental” fees are calculated based on the flow of water through Manitoba Hydro’s hydroelectric facilities. This is essentially a mechanism for the government to directly capture a fraction of the revenue associated with hydroelectric production. Capital taxes are based on the total equity and debt capital being put to use in Manitoba Hydro. Both of these items are considered operating costs for Manitoba Hydro, and are recovered from ratepayers. All other things being equal, it would be reasonable for the government to prefer options where its revenue streams were greater. For the government, these revenue streams are an alternative form of tax, which benefits the provincial budget. It could be objected that if these taxes were not charged to Manitoba Hydro, then electricity costs would be lower, and the government could simply increase some other tax to compensate. However, it is notable that “ratepayers” are not economically identical to “taxpayers”, and hence there is a distributional impact of collecting government revenue through water rentals and capital taxes on Manitoba Hydro.

As noted in the charts below, individuals and families pay a much larger portion of government revenues (through income tax, liquor/lottery/gaming taxes, retail sales tax, etc.) than they do electricity costs (the Residential customer class provided 33% of Manitoba Hydro’s electricity revenues in 2012-13, but personal income taxes and liquor/lottery/gaming taxes represented 34% of Provincial revenues, and then a large share of retail sales tax, land transfer tax and other revenue line items would have to be included). On the other hand, Manitoba businesses and

1 institutions pay a far greater portion of electricity costs than they do government revenues.  
 2 Clearly, government could substitute new provincial taxes for the revenue streams that are  
 3 embedded in electricity costs, and if they did so electricity would become less expensive, but it  
 4 would not necessarily be a simple substitution.

5 **Figure 4. Taxbase and Ratebase Comparison**



6  
 7 Source: Manitoba Estimates, 2013; 62<sup>nd</sup> Annual Report

- 8 • *Minimize Risk of Default on Guaranteed Debt:* As noted above, the Province of Manitoba  
 9 guarantees almost all debt incurred by Manitoba Hydro. While the government charges a fee for  
 10 providing this guarantee, it is a potentially serious burden on the taxpayers of the province. In  
 11 considering the Preferred Development Plan and its alternatives, a significant issue for  
 12 government is minimizing the risk that the province would ever be required to make good on  
 13 the guarantee.

14  
 15 On its face, the legislative requirement that ratepayers cover all costs of Manitoba Hydro (after  
 16 export revenues are deducted) seems to mean that the government would never be called upon  
 17 to pay Manitoba Hydro's debts. After all, if Manitoba Hydro needs more revenue to pay its  
 18 costs, then it can simply request that the PUB raise customer rates. However, in an extreme  
 19 situation of financial distress for Manitoba Hydro (for example, caused by a prolonged drought),  
 20 the need to pay debt costs may conflict with the need to maintain competitive electricity rates.  
 21 For example, if electricity costs were to rise dramatically, implying the need for a substantial  
 22 rate increase, large manufacturers might threaten to close their doors and move production to  
 23 other jurisdictions unless the government intervened to provide assistance. If rates were kept  
 24 low, and Manitoba Hydro simply absorbed the financial losses for a period of years, then  
 25 Manitoba Hydro's status as a financially self-supporting entity would be called into question.  
 26 Credit rating agencies, which currently do not include Manitoba Hydro debt as an obligation of  
 27 the Province of Manitoba, may reconsider that position, at least for a portion of Manitoba  
 28 Hydro's debt, which could have significant implications for the government. What this illustrates  
 29 is that despite the legislation under which Manitoba Hydro operates, a situation of financial

1           distress could force the government to make a difficult political decision. Avoiding the potential  
2           for such situations to arise is therefore assumed to be a priority for the government.

- 3           • *Maximize Job Creation and Economic Development:* Any infrastructure development plan will  
4           entail construction and engineering employment, purchase of supplies, etc., and depending on  
5           where that construction occurs, a range of indirect employment and economic development  
6           activity that benefits different communities across the province to varying degrees. Maximizing  
7           these benefits is an obvious interest of the government in considering the Preferred  
8           Development Plan and its alternatives. Not incidentally, the economic activity that is generated  
9           by construction of large infrastructure also has secondary benefits in increasing government  
10          income and sales tax revenues, as companies and their employees benefit in the form of profits,  
11          salaries and wages. However, infrastructure development must be paid for in the form of  
12          electricity rates over time, and higher electricity rates can lead to a loss of business  
13          competitiveness for the province with an attendant impact on jobs, so the maximization of job  
14          creation and economic development over the long-term is a more subtle issue than it  
15          immediately appears.
- 16          • *Protect the Environment:* Any major infrastructure development will have potential impacts on  
17          the environment that must be understood and potentially balanced against other economic and  
18          social impacts. In the case of the Preferred Development Plan and its alternatives, very different  
19          potential impacts would be felt depending on the choice made. Some alternatives entail direct  
20          impacts on land, flora and fauna through flooding, road construction, etc., while other  
21          alternatives entail air emissions including carbon, oxides of nitrogen, ground level ozone, etc.

### 22           **2.4.3.       Other Stakeholders**

23          In addition to ratepayers and the Government of Manitoba, three other groups bear mentioning as  
24          stakeholders in the decision-making process about the Preferred Development Plan: First Nations, “the  
25          environment” as represented by Environmental Groups, and the Federal Government.

- 26          • First Nations have partnered with Manitoba Hydro in the past on the development of the  
27          Wuskwatim hydroelectric generation facility, and similar arrangements may be expected to  
28          apply to the proposed Keeyask and Conawapa facilities. Given the economic benefits that such  
29          partnerships could bring to affected First Nations, they have a clear interest in the decision. In  
30          addition, since the above facilities are located in lands of traditional concern to First Nations,  
31          potential environmental and social impacts should be taken into account.
- 32          • Environmental groups often challenge government, business and institutional proponents of  
33          large projects with respect to the environmental impacts that a proposed project will engender.  
34          With a single-minded focus on protecting the environment, and on understanding and  
35          mitigating against potential environmental impacts which may not previously have been  
36          brought to light, environmental groups are sometimes a stand-in for “the environment” as an  
37          independent stakeholder in a decision-making process.

- 1       • Given Canada’s constitutional and fiscal relationships, the Government of Canada is often  
2       considered to be the ultimate guarantor of provincial credit.<sup>18</sup> Given the debt guarantee  
3       provided by the Government of Manitoba to Manitoba Hydro, the Government of Canada can,  
4       in some remote sense, be thought of as a guarantor of the debt that would be incurred through  
5       the Preferred Development Plan or its alternatives. In addition, the Government of Canada,  
6       through its authority over navigable waters, inter-provincial environmental issues, and First  
7       Nations, has other, more direct interests in the outcome of the decision-making process.

8       Notwithstanding the notional importance of these three stakeholder groups, it is fairly clear that their  
9       concerns overlap in important ways with those of the Government of Manitoba, even if they may not be  
10      perfectly captured. As a result, these additional stakeholder groups will not be included in any further  
11      analysis in this report, which will limit itself to considering the interests of the two main stakeholders,  
12      Manitoba ratepayers and the Government of Manitoba.

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<sup>18</sup> In the *Credit Analysis* cited above in note 7, Moody’s Investor Service states on p. 5, “Moody’s assigns a high likelihood that the federal government (Aaa, stable) would act to prevent a default by Manitoba. The high likelihood of support reflects Moody’s assessment of the incentive to the federal government of minimizing the risk of potential disruptions to capital markets if Manitoba, or any province, were to default, as well as indications of a moderately positive federal government policy stance as illustrated by the flexibility inherent in the system of federal- provincial transfers.”

### 1   **3. Resource Options**

2   In the Business Case, Manitoba Hydro described multiple electricity resources that could be constructed  
3   in Manitoba to meet anticipated demand. Furthermore, a variety of alternative combinations and  
4   sequences of resources were considered. Many options were discarded because of environmental  
5   concerns or legislative restrictions (e.g., coal and nuclear), while other options were not pursued  
6   because they are currently prohibitively expensive compared to current Manitoba Hydro rates (e.g.,  
7   solar). The options which were fully analyzed in the Business Case included various combinations of new  
8   hydroelectric stations, natural gas-fired stations, and new transmission interconnections with the United  
9   States.

10   One option that did not appear to be thoroughly addressed in the Business Case was the possibility of  
11   largely avoiding new construction through aggressive demand side management programs to flatten the  
12   growth of domestic demand, coupled with new transmission interconnections that could provide  
13   greater peak import capacity and higher total system dependable energy. In response to intervener and  
14   expert consultant requests, Manitoba Hydro is providing additional information to address this possible  
15   option, but did not do so in time for the preparation of this report. As a result, consideration of this  
16   option was not included here.

#### 17       **3.1. Resource Plans and Individual Elements**

18   In the Business Case, Manitoba Hydro provided descriptions and partial analysis of fifteen Resource  
19   Plans, and full analysis including financial models for eight Resource Plans. Each included various  
20   combinations and timelines for several potential resources. Of these eight plans, the “All Gas” (Plan 1)  
21   and Preferred Development Plan (Plan 14) are the most significant contrasts in overall resource strategy,  
22   as they are furthest apart on two orientations: gas vs. hydroelectric, and domestic focus vs. export  
23   focus.

24   Of the remaining six plans that were fully modeled by Manitoba,<sup>19</sup> we dismissed three (plans 2, 7, and  
25   13) because they were essentially similar to other plans, but with less transmission.<sup>20</sup> Even cursory  
26   comparison of Manitoba Hydro’s analysis of plans having similar generation resources coupled with  
27   larger transmission shows the pattern that financial results are superior with additional transmission  
28   capacity. This is consistent with received wisdom in resource planning that transmission  
29   interconnections provide substantial system benefits.

30   For the purposes of our analysis, we limited our focus to the following five Resource Plans.

31

---

<sup>19</sup> Seven plans were not fully modeled (3, 5, 8, 9, 10, 11, 15) because they were either slight variations on others, or they were demonstrated to be clearly inferior through the first two stages of Manitoba Hydro’s analysis.

<sup>20</sup> Plans 2 and 7 include hydroelectric generation but no transmission, and can be contrasted unfavourably to Plans 4, 6, 12 and 14 that all include transmission. Plan 13 includes Keeyask and Conawapa, but only a 250 MW interconnection, whereas both Plans 12 and 14 include a 750 MW interconnection.

1

**Table 6. Resource Plans Examined**

Plan	Elements
1	<p><i>All Gas</i></p> <ul style="list-style-type: none"> <li>• Single cycle natural gas units are added in 2022-23, 2025-26, 2028-29, 2034-35, 2047-48</li> <li>• Combined Cycle natural gas units are added in 2031-32, 2037-38, 2040-41, 2044-45</li> </ul>
4	<p><i>K19/Gas24/250MW</i></p> <ul style="list-style-type: none"> <li>• Keeyask Hydroelectric Station in 2019-20</li> <li>• 250 MW Transmission Interconnect in 2020-21</li> <li>• Single cycle natural gas units are added in 2024-25, 2029-30</li> <li>• Combined Cycle natural gas units are added in 2032-33, 2038-39, 2041-42, 2045-46</li> </ul>
6	<p><i>K19/Gas25/750MW(WPS Inv.)</i></p> <ul style="list-style-type: none"> <li>• Keeyask Hydroelectric Station in 2019-20</li> <li>• 750 MW Transmission Interconnect in 2020-21</li> <li>• Interconnect will be partially owned and funded by a US investor</li> <li>• Single cycle natural gas units are added in 2025-26, 2026-27, 2028-29, 2031-32, 2033-34, 2045-46, 2047-48</li> <li>• Combined Cycle natural gas units are added in 2042-43</li> </ul>
12	<p><i>K19/C31/750MW</i></p> <ul style="list-style-type: none"> <li>• Keeyask Hydroelectric Station in 2019-20</li> <li>• 750 MW Transmission Interconnect in 2020-21</li> <li>• Conawapa Hydroelectric Station in 2031-32</li> <li>• Single cycle natural gas units are added in 2041-42, 2044-45, 2046-47</li> </ul>
14	<p><i>K19/C25/750MW(WPS Inv.)</i></p> <ul style="list-style-type: none"> <li>• Keeyask Hydroelectric Station in 2019-20</li> <li>• 750 MW Transmission Interconnect in 2020-21</li> <li>• Interconnect will be partially owned and funded by a US investor</li> <li>• Conawapa Hydroelectric Station in 2025-26</li> <li>• Single cycle natural gas units are added in 2041-42, 2044-45, 2046-47</li> </ul>

2

Source: NFAT Business Case, Chapter 8

3

Several basic elements are shared between the above Resource Plans, having the following characteristics when added to the existing Manitoba electricity system:

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**Table 7. Resource Elements**

Resource	Dependable Energy	Maximum Energy	Winter Peak Capacity	Maximum On-peak Exported Energy	Maximum Off-peak Imported Energy
209 MW Single Cycle Gas Turbine	2,460 GWh	2,460 GWh	223MW		
308 MW Combined Cycle Gas Turbine	1,688 GWh	1,688 GWh	325 MW		
Keeyask	3,003 GWh	5,400 GWh	630 MW		
Conawapa	4,650 GWh	7,600 GWh	1,300 MW		
250 MW Intertie	Planning Limits		Depends on contracts	1,144 GWh	208 GWh
750 MW Intertie	Planning Limits		Depends on contracts	3,432 GWh	3,120 GWh

2

Source: NFAT Business Case, Chapter 7; SPLASH model outputs provided by Manitoba Hydro

3

The five Resource Plans selected, with their various combinations and timing of resource elements, allow for comparisons of financial performance over time between versions of the Manitoba electricity system with characteristics along several dimensions: Gas/Hydro; Less/More Interconnection; Domestic/Export Focus; Earlier/Later Construction.

4

5

- Gas/Domestic Focus vs. Hydroelectric/Export Focus: Plan 1 vs. Plan 14

6

- Less Interconnect/More Domestic Production vs. More Interconnect/Less Domestic: Plan 4 vs. Plan 6

7

8

- Earlier Hydro construction for Firm Export vs. Later for Domestic: Plan 14 vs. Plan 12

9

- Hydro/Gas vs. Hydro/Hydro: Plan 4 or 6 vs. Plan 14

10

## 3.2. Notable Features

11

### 3.2.1. Contrasting Impact of Resource Elements

12

Natural gas generation resources increase the system's dependable energy, but are unlikely to affect maximum annual energy production to a significant degree. In "wet" years, Manitoba Hydro's existing hydroelectric generation facilities are more than sufficient to satisfy domestic needs and create a

13

14

1 surplus for export. In such years, gas generation facilities will operate to the minimum extent. In “dry”  
2 years, natural gas units have the effect of increasing substantially the minimum system dependable  
3 energy, as well as contributing to peak winter capacity.

4 Hydroelectric generation resources increase both the system’s dependable energy, AND the maximum  
5 energy possible in any given year, therefore driving up the average exports that should be expected  
6 from the system. Hydroelectric generation facilities therefore are inherently “export-oriented”, and beg  
7 the question of the electricity system’s transmission capacity for export (if there is insufficient export  
8 capacity, then in “wet” years water might have to be spilled/wasted).

9 Transmission interconnections potentially provide benefits for meeting peak capacity needs (if coupled  
10 with firm import contracts), and increase the ability to import power in “dry” years and export it in  
11 “wet” years. They are multi-purpose resources and can contribute in a variety of ways to system  
12 financial performance over time.

### 13 **3.2.2. Long Term Plan but Near Term Differentiation**

14 All fifteen Resource Plans proposed by Manitoba Hydro include natural gas-fired generation elements,  
15 though in some cases not until the 2040s. While in Chapter 7 of the Business Case Manitoba Hydro  
16 identified a number of other potential hydroelectric projects in the province,<sup>21</sup> they make no suggestion  
17 that any of these could be practical parts of current planning, because based on the stage of current  
18 project development and relative prices, they are uneconomic. However, it is notable that there is  
19 mention of the possibility that in the future several hydroelectric projects could be combined to create a  
20 more competitive alternative.<sup>22</sup> This suggests that choice of a Resource Plan today, such as the Preferred  
21 Development Plan (which only includes natural gas-fired generation in the distant future), could later be  
22 revisited in light of the opportunity to pursue additional hydroelectric energy. Similarly, even plans  
23 which indicate natural gas both immediately and in the longer term could be revisited at any time in the  
24 future if it is determined that hydroelectric options have become more attractive.

25 In short, while the Resource Plans are structured as long term multi-stage projects for the purposes of  
26 analysis, their true value is in highlighting the potential longer term implications of resource choices  
27 made in the near future. It should be assumed that all Resource Plans are subject to revisit and  
28 modification as they unfold.

### 29 **3.3. Planning Variables**

30 All electricity resource planning exercises entail risks, because they depend very much on future  
31 conditions, which are ultimately unknowable in advance. It is highly unlikely in any jurisdiction that there  
32 is a choice that is universally superior to all other options in all possible future conditions. Instead, the  
33 challenge is consider a wide variety of possible future conditions, and determine if each alternative is

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<sup>21</sup> Please see Business Case, c. 7, pages 23 to 28.

<sup>22</sup> Ibid., p. 28.

1 robust in the way it performs across them. Results of such analysis would indicate the costs, benefits  
2 and risks that would be accepted by stakeholders if that option were chosen.

3 Manitoba Hydro has carefully screened its resource alternatives on the basis of safety and reliability  
4 standards. All of the options examined in detail in the Business Case passed those tests. As a result, the  
5 expected future performance of the *physical* electricity system is not an issue in the selection among  
6 options: all of the options considered would satisfy Manitoba's electricity needs safely and reliably  
7 according to the standards and criteria in place in Manitoba. What is at issue is the expected *financial*  
8 performance of the various resource options under future conditions that might obtain. There are a  
9 number of factors which affect Manitoba Hydro's financial performance, and which will vary in the  
10 future, in ways that are increasingly unpredictable further out in time. To the extent possible, testing the  
11 resource options consists of imagining plausible future paths for these variables, and calculating how the  
12 resource plan would perform in that possible future.

### 13 **3.3.1. Manitoba Demand**

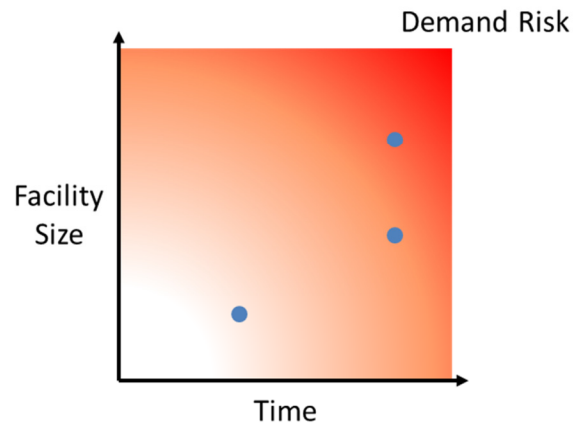
14 The Preferred Development Plan and its alternatives were created because of a perceived need for new  
15 resources. The timing of that need, however, depends very much on the rate of demand growth in  
16 Manitoba. If demand growth is relatively high, then new resources will be required sooner, and if  
17 relatively lower, then later. The difference can amount to a few years, according to the analysis  
18 presented by Manitoba Hydro. One risk is that capital will be spent earlier than necessary, which means  
19 that a facility will not be fully utilized for a period of time. This loss of efficiency would be costly to  
20 ratepayers, but likely only temporarily.

21 Considering the different options, the risk of being incorrect about the timing of the requirement for  
22 new resources is in some measure proportional to the time required for development and construction  
23 of a new facility. For example, a natural gas-fired generation facility may take three years to build and  
24 put into service, while a hydroelectric facility may take five to seven. Given uncertainty in demand  
25 growth, the further out in time the projection is, the greater the likelihood for error. From this  
26 perspective, facilities which can be constructed more quickly have an advantage, because they can be  
27 more accurately targeted to the timing of needs.

28 Over the longer-term, however, the more important risk with respect to demand growth concerns the  
29 size and longevity of proposed resources. Large, extremely long-lived resources are susceptible to  
30 becoming "stranded assets": facilities which are built to serve a need which never fully materializes, and  
31 are therefore inordinately expensive for the purpose they ultimately serve. In the case of electricity  
32 resource options in Manitoba, this risk would be expressed in the case of Keeyask or, more likely,  
33 Conawapa, where the risk is that domestic Manitoba demand growth in the future could stall long  
34 before an additional 1,300 MW of capacity and 5,000 GWh of energy are fully required. The reasons for  
35 a long-term change in direction could be many, but most easily conceived of are some change in  
36 technology which allows consumers to dramatically reduce their consumption (e.g., a new cooling  
37 technology).

1 It is important to note, however, that “demand” need not specifically apply to Manitoba domestic  
 2 demand. A new hydroelectric generation facility in Manitoba could, if Manitoba demand is lower than  
 3 anticipated, simply serve export demand. However, from a financial perspective Manitoba ratepayers  
 4 would then in effect be investors in a pure export project, rather than electricity consumers of a  
 5 necessary facility which may for a time be larger than needed.

6 **Figure 5. Demand Risk and Electricity Infrastructure**



7  
 8 Gas plants, with a much shorter typical life of only twenty-five years and flexibility in size (smaller units  
 9 can be built singly or in multiple sets, as required), do not suffer nearly to the same degree from  
 10 demand risk. Transmission resources, with an average life between the two types of generation  
 11 facilities, occupy a middle level of risk, also mitigated by the fact that they are flexible enough to serve  
 12 several different purposes depending on need (i.e., winter peak capacity, higher exports in “wet” years,  
 13 higher imports in “dry” years, etc.).

### 14 **3.3.2. Fuel Availability/Hydrology**

15 Electricity generation plants require inputs – or fuel – to operate. In the case of hydroelectric facilities,  
 16 this fuel is water that derives from precipitation in relevant watersheds. For thermal plants, that fuel will  
 17 be coal, natural gas, diesel fuel or some other hydrocarbon or biomass. Fuels for wind turbines and solar  
 18 panels are self-explanatory.

19 Manitoba Hydro did not explicitly address hydrology/fuel availability in their financial modeling, except  
 20 to test the sensitivity of the Resource Plans to a prolonged drought. They assumed that natural gas was  
 21 available upon request for any number of new facilities. This is now probably a fair and reasonable  
 22 assumption, given the existing identified natural gas resources in North America (note that ten years  
 23 ago, before the “shale gas revolution”, many analysts believed that North America might run short of

1 recoverable natural gas resources, and be forced to import liquefied natural gas, which would have  
2 represented real concerns about availability).<sup>23</sup>

3 Critically, Manitoba Hydro assumed average hydroelectric performance in every year throughout their  
4 models.<sup>24</sup> This allows them to consider factors which are longer-term than the annual swings in  
5 precipitation that lead to more or less hydroelectric generation.

6 However, review of the information on historical water flows supplied by Manitoba Hydro in the NFAT  
7 Business Case Figure 5.8 suggests that changes in water flows can have an impact beyond any one-year  
8 or short-term period. For example, on a five-year basis, average water flow has ranged from 70% of  
9 average to 130% of average. On a ten-year basis the range narrows only slightly to 80% to 120%. Even  
10 on a twenty-five-year basis the range of averages is 90% to 110%. Given that Manitoba is so heavily  
11 dependent on hydroelectric energy currently, and will continue to be so for an extended period even in  
12 the All Gas Resource Plan, understanding the impact of hydrology on the choice of Resource Plan  
13 appears to be potentially important.

### 14 **3.3.3. Fuel Prices**

15 The price of water as a “fuel” for hydroelectric facilities is set by the government, in the form of the  
16 water rental fee. This fee has been stable, and is assumed to continue at its current level for the  
17 foreseeable future. To take into account the general increase in prices, it is prudent to assume that the  
18 water rental fee will rise by inflation in the more distant future. However, the Government of Manitoba  
19 could change the water rental fee at any time of its choosing, which would have an impact on the  
20 relative attractiveness of hydroelectricity.

21 Natural gas prices are extremely volatile, and a review of prices over the past twenty years  
22 demonstrates the degree of uncertainty that should be placed on any forward estimates. From the  
23 perspective of Manitoba Hydro’s production costs, however, fuel prices are not currently very important  
24 to financial results. Natural gas-fired generators are a small part of Manitoba generation capacity, and  
25 even in the All Gas Resource Plan it will take many years for the system as a whole to become very  
26 sensitive to natural gas prices. However, ultimately the balance between hydroelectricity and natural  
27 gas-fired electricity would shift significantly enough that fuel prices would have a stronger impact on net  
28 income.

29 Another expert consultant to the PUB has commented on the natural gas price assumptions adopted by  
30 Manitoba Hydro, not because of the role of natural gas prices in Manitoba’s production costs, but  
31 because of the impact of natural gas prices on the next variable addressed.<sup>25</sup>

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<sup>23</sup> See for example the International Energy Agency *World Energy Outlook 2013* for a discussion on natural gas availability. Also see the *BP World Energy Outlook 2035*, or the United States Energy Information Administration *Annual Energy Outlook*.

<sup>24</sup> The average chosen is the average hydroelectric output that would result from the application to the planned hydroelectric facilities in each Resource Plan of the water flows of the past 99 years. In other words, assuming that a Resource Plan contemplated no new hydroelectric facilities, and the continued maintenance and repair of all existing facilities, then approximately 31,000 GWh of annual hydroelectric production would be assumed.

### 3.3.4. Export and Import Prices

As noted above, over the past ten years Manitoba Hydro delivered a third of its electricity (measured at delivery point) to export markets, largely because the province's hydroelectric generation facilities were producing far more power than was domestically required. At the same time, it improved the financial value of its system by importing power at off-peak times while holding back hydroelectric generation, and then sold power into export markets at peak value times. When needed, especially in the drought year 2003-04, power was imported in large volumes to compensate for diminished hydroelectric production.

Prices paid per MWh of electricity by export customers are fundamental to the value of all of these transactions, and those prices change over time. A certain portion of these sales were through firm contracts, where prices are fixed for the term (generally rising with an inflation and/or other index), but a majority was exposed to whatever price was prevailing in the market. Given the destination for the vast majority of Manitoba's export electricity, the relevant market is the MISO market in the United States.

Prices in the MISO market are fundamentally out of Manitoba's control. MISO is a much larger system, and its supply and demand dwarfs that of Manitoba. At certain times Manitoba's transactions may have an impact on the marginal price in the market (especially regionally, where system congestion effects become important), but Manitoba is essentially a price taker. Another independent expert consultant retained by the PUB has commented in detail on the assumptions and expectations about future MISO prices.<sup>26</sup>

As noted above, building hydroelectric facilities as part of the chosen Resource Plan has the net effect of making Manitoba Hydro's financial results more dependent on export results, whose value will in turn be determined by both the quantity and price. Testing the Resource Plans with respect to a range of potential export/import prices over time is critical to estimating future impacts of the choice being made.

### 3.3.5. Construction Costs

Until a project is completed, its costs can be estimated, but not known. Given the size of some of the projects being considered, measured both in dollars, complexity and time required for development and construction, the risks associated with construction can be significant.

Manitoba Hydro appears to have made every effort to carefully estimate the cost of constructing different resources, while putting ranges around them to allow for testing of the financial consequences if errors are made. Another independent expert consultant retained by the PUB has provided

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<sup>25</sup> Please see the report to the PUB of Potomac Economics.

<sup>26</sup> Ibid.

1 commentary on the construction cost assumptions made by Manitoba Hydro, and the price ranges that  
2 they have assumed.<sup>27</sup>

3 It is important to note, however, that despite the best efforts of proponents, large construction projects  
4 do sometimes go horribly wrong. History includes cautionary tales such as the Darlington Nuclear Plant  
5 in Ontario (195% over budget), the “Big Dig” in Boston (190% over budget), the Channel Tunnel (80%  
6 over budget), and the Denver International Airport (70%), among many others. Hydro dam projects have  
7 faced similar situations on occasion.

8 More recently and locally, the construction of the Wuskwatim hydroelectric facility in Manitoba suffered  
9 from substantial cost increases because of the unexpected rise in prices for commodities such as cement  
10 and steel, and the spike in labour and engineering costs driven by infrastructure spending across Canada  
11 and the rest of North America.

12 As a result, it is important to test the performance of Resource Plans in the face of different construction  
13 cost scenarios.

### 14 **3.3.6. Cost of Capital**

15 Manitoba Hydro’s capital is a combination of retained earnings and debt. Retained earnings are driven  
16 in part by the rates approved by the PUB for electricity in Manitoba, which nominally should include a  
17 “return on equity” component in order to ensure that Manitoba Hydro actual earns net income that can  
18 be retained.

19 As noted above, Manitoba Hydro depends on the Government of Manitoba to raise debt from Canadian  
20 and international capital markets. Manitoba faces the prevailing rates of interest, and has no control  
21 over them over time (except insofar as the Province’s state of finances affects its credit rating and hence  
22 the premium that must be paid compared to riskless debt instruments). Equity rates on regulated  
23 entities are typically set in relation to interest rates. Since interest rates are themselves affected by the  
24 general inflation rate, all of these factors often move in concert.

25 From the perspective of calculating the performance of Resource Plans in the future, various  
26 combinations of debt, equity and inflation rates should be tested, as these can have profound impacts  
27 on financial performance.

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<sup>27</sup> Please see the report to the PUB of Knight Piésold Consulting.





TAB 9

**REFERENCE:**

Tab 4, Page 31

**PREAMBLE TO IR (IF ANY):**

Page 31 of Tab 4: Financial Target and Uncertainty Analysis states:

S&P has clarified its rating methodology such that it now defines “self-supporting” as maintaining stand-alone investment grade credit metrics. Since Manitoba Hydro does not meet this standard, Manitoba Hydro’s debt is now **included** in the tax supported debt of the Province. S&P considers Manitoba Hydro to have a “highly leveraged” financial risk profile.

**QUESTION:**

- a) When did S&P make this clarification?
- b) Please provide a reference to this clarification in terms of S&P methodology documentation or publications.
- c) Please provide S&P’s definition of “investment grade” as it pertains to Manitoba Hydro.
- d) Please provide Manitoba Hydro’s stand-alone credit rating per S&P.
- e) Please discuss the detailed standards that Manitoba Hydro would have to meet in terms of Debt:Equity, net income, cash flow, etc. to meet investment grade status under S&P’s methodology.
- f) If Manitoba Hydro is no longer determined to be self-supporting per S&P, please indicate what percentage of Hydro’s debt was transferred to the province for the purposes of determining the province’s rating and provide specific references to the S&P rating reports where these values are calculated.
- g) If S&P has transferred 100% of Manitoba Hydro’s debt to the province for the purpose of rating the province, please provide Manitoba Hydro’s understanding of the treatment of Hydro’s revenues and rate competitiveness in the metrics used to evaluate the province’s credit rating.
- h) Please provide a summary of the other major Canadian Crown Corporations (Manitoba and other provinces) in regard to their stand-alone ratings and status as self-supporting

entities, and indicate any changes to self-supporting status resulting from the S&P definitional change.

- i) If Manitoba Hydro is not self-supporting based on S&Ps analysis, and is consolidated into the Manitoba Government debt, please indicate the treatment by S&P for the high level of payments to government that are made by Manitoba Hydro to the Manitoba Government. Are these payments now netted out on consolidation?
- j) Please confirm that DBRS stated: "... a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province's credit profile" (Appendix 4.4, page 2 of 40). Please indicate why Manitoba Hydro cites an equity injection as possibly a beneficial action in light of this statement by DBRS that it could put an adverse impact on the Province's ratings (which are what ultimately determines Hydro's interest rates).
- k) Please provide a copy of all S&P Credit Rating Reports for Manitoba Hydro and the Province of Manitoba over the past 3 years.

**RATIONALE FOR QUESTION:**

**RESPONSE:**

- a) S&P has clarified its rating methodology such that it now defines "self-supporting" as maintaining stand-alone investment grade credit metrics. Manitoba Hydro became aware of this clarification on July 14, 2016; the date that S&P announced that it no longer considered MHEB to be self-supporting mainly due to its high and rising leverage.
- b) When Manitoba Hydro was notified of the change to self-supporting status, Manitoba Hydro held conference calls with both the sub-sovereign analyst at S&P as well as the utility analyst. S&P identified, during these calls, that the criteria employed for the determination of self-supporting status was the requirement for the utility to maintain an investment grade stand-alone credit profile. S&P viewed MHEB, on a stand-alone basis, to have a sub-investment grade credit profile (lower than BBB-). This criteria is also defined in the document *Methodology For Rating Non-U.S. Local And Regional Governments* which can be found as Attachment 1 to this response.<sup>1</sup>

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<sup>1</sup> Standard & Poors Methodology For Rating Non-U.S. Local And Regional Governments, page 44

Response to parts c) to e):

It is Manitoba Hydro’s understanding that according to S&P’s rating methodology within their document titled *Criteria| Corporates | General: Corporate Methodology* (which can be found as Attachment 2 to this response) S&P evaluates an entity’s financial and business risk profiles in order to arrive at an anchor credit rating. Table 18 from S&P’s *Criteria| Corporates | General: Corporate Methodology* document summarizes the ratios that are considered in their financial risk profile analysis.<sup>2</sup>

Table 18

Cash Flow/Leverage Analysis Ratios--Medial Volatility							
	--Core ratios--		--Supplementary coverage ratios--		--Supplementary payback ratios--		
	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest (x)	EBITDA/interest (x)	CFO/debt (%)	FOCF/debt (%)	DCF/debt (%)
Minimal	50+	less than 1.75	10.5+	14+	40+	30+	18+
Modest	35-50	1.75-2.5	7.5-10.5	9-14	27.5-40	17.5-30	11-18
Intermediate	23-35	2.5-3.5	5-7.5	5-9	18.5-27.5	9.5-17.5	6.5-11
Significant	13-23	3.5-4.5	3-5	2.75-5	10.5-18.5	5-9.5	2.5-6.5
Aggressive	9-13	4.5-5.5	1.75-3	1.75-2.75	7-10.5	0-5	(11)-2.5
Highly leveraged	Less than 9	Greater than 5.5	Less than 1.75	Less than 1.75	Less than 7	Less than 0	Less than (11)

In discussions with S&P, they indicated that while S&P has two core ratios for assessing financial risk, for regulated utilities, analysts focus mostly on the FFO/Debt ratio. The supplementary ratios are utilized if there is a divergence between the two core ratios; in other words, if one core ratio indicates ‘significant leverage’ and the other core ratio indicates ‘aggressive leverage’ then analysts will rely on the secondary ratios for direction as to classification. The 3 year average of Manitoba Hydro’s FFO/debt ratio for the last three fiscal years was 2.2% and therefore places MHEB’s financial risk profile into the highly leveraged category.

It is Manitoba Hydro’s understanding that in assessing the business risk profile, S&P looks at Country Risk, Industry Risk and Competitive Position. For regulated utilities in Canada, the first two are low, so the focus of the business risk profile is on Competitive

<sup>2</sup> Ratings Direct, *Criteria| Corporates| General: Corporate Methodology* dated November 19, 2013, page 35.

Position. For regulated utilities, the components of Competitive Position are weighted as follows:

- o Regulatory advantage assessment 60%
- o Scale, scope and diversity 20%
- o Operating efficiency 20%

At 60% weighting, the regulatory advantage assessment is MHEB's largest business risk component. The following is quoted directly from the *Criteria/ Corporates/ Utilities: Key Credit Factors For the Regulated Utilities Industry* (which can be found as Attachment 3 to this response):

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

Regulatory stability:

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

Tariff-setting procedures and design:

- Recoverability of all operating and capital costs in full
- Balance of the interests and concerns of all stakeholders affected
- Incentives that are achievable and contained

Financial stability:

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

Regulatory independence and insulation:

- Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
- Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event”<sup>3</sup>

Table 3 from S&P’s *Criteria | Corporates | General: Corporate Methodology* document (found as Attachment 2 to this response) combines the financial and business risk profile in order to determine the anchor credit rating.<sup>4</sup>

Table 3

Combining The Business And Financial Risk Profiles To Determine The Anchor						
	--Financial risk profile--					
Business risk profile	1 (minimal)	2 (modest)	3 (intermediate)	4 (significant)	5 (aggressive)	6 (highly leveraged)
1 (excellent)	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
2 (strong)	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
3 (satisfactory)	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
4 (fair)	bbb/bbb-	bbb-	bb+	bb	bb-	b
5 (weak)	bb+	bb+	bb	bb-	b+	b/b-
6 (vulnerable)	bb-	bb-	bb-/b+	b+	b	b-

With a “highly leveraged” financial risk profile, the business risk profile would need to be “excellent” in order to achieve an anchor rating with a BBB- ceiling. S&P did not disclose MHEB’s business risk profile, however with a stand-alone credit profile deemed to be sub-investment grade, it is assumed the business risk profile was not considered to be “excellent”.

- f) All of the provincial advances to Manitoba Hydro are included in the Province’s debt burden for the purposes of determining its credit rating. From S&P’s Global Ratings report dated July 29, 2016 on the Province of Manitoba:

<sup>3</sup> Ratings Direct, *Criteria | Corporates | Utilities: Key Credit Factors For the Regulated Utilities Industry* copyright 2016, page 5.

<sup>4</sup> Ratings Direct, *Criteria | Corporates | General: Corporate Methodology* dated November 19, 2013, page 8.

“Our assessment of the province's debt burden fully incorporates the debt on-lent to MHEB (nearly 40% of total tax-supported debt), whereas previously we had considered MHEB's status as a self-supporting entity to be a mitigating factor.”<sup>5</sup>

- g) Should all debt on-lent to the MHEB be included in the Province’s metrics for the purpose of evaluating the province’s credit rating, it is unclear to Manitoba Hydro what adjustments are made by S&P to reported revenues.
- h) The following table provides a summary of other major Canadian Crown Corporations in regard to their status as self-supporting entities as considered by S&P as well as the date of the change in self-supporting status as evidenced by the publication of their respective provincial credit rating reports. S&P does not publish stand-alone ratings for the Crown Corporations.

Crown Corporation	Self-Supporting Status	Date of Change in Status by S&P
Manitoba Hydro	No	July 14, 2016
BC Hydro	Yes	N/A
Hydro Quebec	Yes	N/A
SaskPower	No	June 24, 2016
NB Power	No	June 23, 2016
Nalcor Energy	No	July 19, 2016

- i) Manitoba Hydro is unaware of the treatment by S&P with respect to the payments to government that are made by Manitoba Hydro.
- j) DBRS did state: “... a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province’s credit profile” (Appendix 4.4, page 2 of 40). However, DBRS also states the following:

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<sup>5</sup> S&P’s Global Ratings report dated July 29, 2016 on the Province of Manitoba, page 3

“... the Utility has begun reviewing initiatives to help alleviate pressure on its key financial ratios, such as improving operational efficiencies, requesting annual rate increases higher than the previously planned 3.95%, as well as a potential equity injection from the Province. DBRS sees these initiatives, if actualized, as positive to Manitoba Hydro’s financial profile, as they will provide some financial flexibility for the Utility, especially in the event of adverse drought conditions or further cost overruns on the projects.”<sup>6</sup>

Manitoba Hydro cites an equity injection as possibly a beneficial action as this would assist in restoring the financial health of the Corporation in a timely manner. Currently, DBRS highlights MHEB’s high leverage as the #1 challenge for the Corporation.<sup>7</sup>

- k) Manitoba Hydro does not have permission from S&P to place the Credit Rating Reports on the public record. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of these reports pursuant to Rule 13.

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<sup>6</sup> DBRS Rating Report on the MHEB dated November 25, 2016 page 1.

<sup>7</sup> DBRS Rating Report on the MHEB dated November 25, 2016 page 2.



**TAB 10**

*TVA, For Generations to Come, presentation  
dated June 2, 2017, available at:*

**[http://www.snl.com/Cache/1500100374.PDF?  
O=PDF&T=&Y=&D=&FID=1500100374&iid=406](http://www.snl.com/Cache/1500100374.PDF?O=PDF&T=&Y=&D=&FID=1500100374&iid=406)**

**3363**

TAB 11

## RATING METHODOLOGY

## US Public Power Electric Utilities With Generation Ownership Exposure

This rating methodology replaces "US Public Power Electric Utilities With Generation Ownership Exposure", last revised on March 1, 2016. We have updated some outdated links and removed certain issuer-specific information.

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### Analyst Contacts:

<b>NEW YORK</b>	<b>+1.212.553.1653</b>
Kevin Rose	+1.212.553.0389
<i>Vice President - Senior Analyst</i>	
kevin.rose@moodys.com	
Dan Aschenbach	+1.212.553.0880
<i>Senior Vice President</i>	
dan.aschenbach@moodys.com	
Angelo Sabatelle	+1.212.553.4136
<i>Associate Managing Director</i>	
angelo.sabatelle@moodys.com	
Michael Mulvaney	+1.212.553.3665
<i>Managing Director - Project Finance</i>	
michael.mulvaney@moodys.com	

» contacts continued on the last page

### Summary

This rating methodology explains our approach to assessing credit risk for US Public Power Electric Utilities with Generation Ownership Exposure. This document provides general guidance that helps issuers, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for US public power electric utilities whose credit profile is largely influenced by power generation ownership. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This report includes a detailed scorecard. The scorecard is a reference tool that can be used to approximate credit profiles within the US public power electric utilities with generation ownership exposure sector in most cases. The scorecard provides summarized guidance for the factors that are generally most important in assigning ratings to issuers in the US public power electric utility sector whose credit profile is largely influenced by power generation ownership. However, the scorecard is a summary that does not include every rating consideration. The weights shown for each factor in the scorecard represent an approximation of their importance for rating decisions but actual importance may vary substantially. The scorecard-indicated rating is not expected to match the actual rating of each issuer.

The scorecard contains five factors that are important in our assessment for ratings in the US public power electric utilities with generation ownership exposure sector:

1. Cost Recovery Framework Within Service Territory
2. Willingness and Ability to Recover Costs with Sound Financial Metrics
3. Generation and Power Procurement Risk Exposure
4. Competitiveness
5. Financial Strength and Liquidity

## Factor 5: Financial Strength and Liquidity (30% Weight)

### Why it Matters

A utility's ultimate credit profile must incorporate its financial metrics, as any public power utility that is substantially weaker than its peers in terms of liquidity, cash flow generated in relation to debt service, or debt relative to the value of its asset base will generally have a higher probability of default. Public power electric utilities, especially those that own generation, are typically capital intensive with an ongoing need to invest in their assets and have a higher leverage profile than their investor-owned counterparts, which typically necessitates consistent access to debt capital markets to assure adequate sources of funding. A utility's financial strength is key to its maintaining this market access and, in general, its long-term viability. Public power electric utilities with weaker metrics may find that their access to markets decreases rapidly when markets shift or their debt load is viewed as unsustainable.

When examining financial strength, there is no single measure that can predict the likelihood of default. We utilize metrics that are indicators for liquidity resources in relation to operating and maintenance expenses, the capacity of the issuer to service its debt and the size of its debt burden relative to its assets. Comparison to peers is typically useful.

### How We Assess Financial Strength and Liquidity for the Scorecard

#### Adjusted Days Liquidity on Hand Ratio (10% weight)

The formula for Adjusted Days Liquidity on Hand Ratio (days) is as follows:

(Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt portion of annual payments made to JAAs under take-or-pay contracts)

For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines (described below) are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. Some utilities have commercial paper programs that are backed by letters of credit, and the unused portion is included when the LC issuing bank is rated P-1.

To be included in this ratio, eligible bank lines must meet all of the following criteria:

- » Committed facilities
- » Remaining tenor of committed drawdown availability is at least one year
- » Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- » If bilateral, provided by a bank rated P-1
- » If syndicated, provided by a group of banks predominantly rated P-1

Bank lines that do not meet the eligibility requirements are not included in calculating the ratio. However, depending on their strength, they may be assessed qualitatively as a credit positive if they constitute incremental liquidity as part of prudent financial policies. While bank lines over a year are included in the ratio, bank line maturities are considered in the broader context of a utility's future cash flow requirements, including capital expenditures, and loan/bond amortizations. Longer dated tenors are more favorable from a credit perspective.

Debt Ratio (10% weight):

$(\text{Gross debt} - \text{Debt service funds} - \text{Interest payable and debt service reserve funds}) / (\text{Gross fixed plant assets} - \text{Accumulated depreciation on plant} + \text{Net working capital})$

Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

Adjusted Debt Service or Fixed Obligation Charge Coverage Ratio (10% weight)

In order to improve comparability between utilities that have chosen different generation procurement and financing strategies, there are some differences between their coverage ratios. For a public power electric utility that does not have any generation exposure via take-or-pay contracts with JAAs, we use the Adjusted Debt Service Coverage Ratio. For a utility that purchases some portion of its power under a take-or-pay contract with a JAA that has issued debt related to fulfilling that contract, we use the Fixed Obligation Charge Coverage Ratio.

Adjusted Debt Service Coverage Ratio:

$(\text{Annual recurring revenues plus interest income} - \text{Recurring annual cash operating expenses} - \text{GFTs}) / \text{Aggregate annual debt service}$

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Most public power utilities transfer a portion of their surplus revenues to a municipal government at an agreed upon level. While the transfers typically come after debt service in the legal flow of funds, in practical terms the transfer is a requirement that in many cases is made on a monthly basis. Therefore, our Adjusted Debt Service Coverage Ratio treats the transfer as akin to an operating expense, which differentiates it from the traditional bond ordinance debt service coverage ratio. We utilize the adjusted debt service coverage ratio in the scorecard because it provides a better overall indicator of a utility's operating results that provides greater comparability among public power electric utilities. In some cases, the bond ordinance coverage ratio may also be important to our analysis.

Fixed Obligation Charge Coverage Ratio:

$(\text{Annual recurring revenues plus interest income} - \text{Recurring annual cash operating expenses} - \text{GFT} + \text{Debt service portion of annual payments made to JAAs under take-or-pay contracts}) / (\text{Aggregate annual debt service} + \text{Debt service portion of annual payments made to JAAs under take-or-pay contracts})$

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Many public power enterprises finance the development or purchase of generation assets through JAAs under take-or-pay contracts to increase power reliability, diversify the power resource mix, and lower power costs. We view a take-or-pay contractual obligation as fixed and the debt service portion of annual payments made to the JAA as a debt service obligation of the utility.

Financial Strength and Liquidity	Weight	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand <sup>9</sup> (3-year avg) (days)	10%	≥ 250	150 - 250	90 - 150	30 - 90	15 - 30	< 15
Debt ratio (3-year avg) <sup>10</sup> (%)	10%	< 35%	35% - 60%	60% - 75%	75% - 90%	90% - 100%	≥ 100%
Adjusted Debt Service Coverage <sup>11</sup> OR	10%	≥ 2.5x	2x - 2.5x	1.5x - 2x	1.1x - 1.5x	1x - 1.1x	< 1x
Fixed Obligation Charge Coverage <sup>12</sup> (3-years avg) (x)							

## Factors 6, 7, and 8

These factors result in upward or downward adjustments to the preliminary scorecard-indicated rating resulting from factors 1-5. In aggregate, these factors can result in a total of 3 notches up or down from the preliminary scorecard-indicated rating to arrive at the scorecard-indicated rating. In the unusual circumstance that the importance of these factors in assessing the issuer's credit profile is greater than can be incorporated within the range of this notching band, they may nonetheless be incorporated in the actual rating – please see Other Rating Considerations.

### Factor 6: Operational Considerations

Operational considerations include construction risks and whether the utility is a vital service provider. In aggregate, operational considerations can result in adjustments ranging from 2 notches down to one notch up.

We assess each utility's construction risks and may apply up to 2 negative notches to the preliminary scorecard-indicated rating in accordance with the construction program's complexity, technical difficulty, scale relative to the size of the utility, and risk-allocation between the utility and its contractors for cost over-runs and delays, including liquidated damages. We may consider feasibility studies and other reports provided by third-party consulting engineers to inform our assessment of the risks associated with a particular project. Risk mitigation may include fixed-price contracts with liquidated damages, performance

<sup>9</sup> Defined as: (Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt service portion of annual payments made to JAAs under take-or-pay contracts). For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. To be included in this ratio, eligible bank lines must meet all of the following criteria:

- » Committed facilities
- » Remaining tenor of committed drawdown availability is at least one year
- » Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- » If bilateral, provided by a bank rated P-1
- » If syndicated, provided by a group of banks predominantly rated P-1

<sup>10</sup> Defined as: (Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets – Accumulated depreciation on plant + Net working capital). Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

<sup>11</sup> Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service. In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

<sup>12</sup> Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts).