CAC/MSOS Exhibit 16

MANITOBA HYDRO
2010-2011 GENERAL RATE APPLICATION

CONSUMER ASSOCIATION OF CANADA (Manitoba Branch) and MANITOBA SOCIETY OF SENIORS

BOOK OF DOCUMENTS

April 5, 2011

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PUB/MH I-59

Subject: **Tab 6: Capital Expenditures**
Reference: **CEF 09-1/CEF 08-1**

a) **Please provide the most recent budget estimates for the major components of Bipole III:**

   i. **Northern Converter**
   ii. **Transmission Lines**
   iii. **Southern Converter**

ANSWER:

Please see the following table for the major components of Bipole III.

COMPONENTS	**APPROVED BUDGET (IN THOUSANDS)**
Transmission Base Estimate	814,312
Escalation & Interest	319,336
Subtotal	1,133,648
Northern Converter Base Estimate	388,482
Southern Converter Base Estimate	485,116
Escalation & Interest - Converters	240,591
Subtotal	1,114,189
TOTAL	**2,247,837**

CAPITAL EXPENDITURE FORECAST (CEF10)
(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
ELECTRIC												
Major New Generation & Transmission												
Wuskwatim - Generation	1 274.6	300.8	130.3	16.2	-	-	-	-	-	-	-	447.2
Wuskwatim - Transmission	291.2	35.7	21.2	-	-	-	-	-	-	-	-	56.9
Herblet Lake - The Pas 230 kV Transmission	74.9	22.2	6.0	-	-	-	-	-	-	-	-	28.3
Keeyask - Generation	5 636.9	71.2	152.5	179.2	312.3	379.5	683.0	749.1	1 080.5	816.6	640.1	5 064.0
Conawapa - Generation	7 770.8	42.4	104.4	105.2	83.3	166.4	298.6	333.4	325.1	623.4	1 038.0	3 110.1
Kelsey Improvements & Upgrades	301.7	42.7	34.7	28.5	12.5	-	-	-	-	-	-	118.6
Kettle Improvements & Upgrades	165.7	17.5	18.7	21.6	22.2	15.4	7.3	7.5	7.6	7.7	7.9	133.6
Pointe du Bois Spillway Replacement	398.2	18.6	24.4	92.7	103.6	89.2	31.5	0.5	-	-	-	360.5
Pointe du Bois - Transmission	86.0	20.5	15.6	25.0	13.1	3.1	-	-	-	-	-	77.3
Bipole III - Licensing & Properties	123.5	9.1	18.9	9.6	9.3	9.8	11.1	5.9	11.2	0.2	-	85.1
Bipole III - Transmission Line	958.4	2.8	5.4	38.2	87.9	181.9	313.1	133.0	192.2	-	-	954.6
Keewatinoow Converter Station	466.3	6.3	11.8	60.5	78.3	56.0	81.1	43.5	8.2	118.8	-	464.6
Keewatinoow AC Collector System	80.9	1.9	7.4	32.5	35.2	0.9	1.3	0.7	0.9	-	-	80.8
Riel Converter Station	618.7	36.7	31.7	58.7	135.1	128.1	14.4	5.0	1.7	196.2	-	607.7
Riel 230/500 kV Station	267.6	70.2	66.8	29.4	28.9	41.3	-	-	-	-	-	236.5
Ontario 100 MW Firm Import Upgrades	4.8	-	0.6	2.2	1.9	-	-	-	-	-	-	4.8
Dorsey - US Border New 500 kV Transmission Line	204.8	-	0.1	0.9	1.9	2.4	11.7	64.5	93.5	28.9	-	204.0
St Joseph Wind Transmission	6.5	5.5	-	-	-	-	-	-	-	-	-	5.6
Demand Side Management	NA	36.9	38.0	39.1	38.6	36.2	29.5	25.0	23.0	21.9	20.4	308.6
Waterways Management Program	NA	5.5	-	-	-	-	-	-	-	-	-	5.5
		746.6	688.6	739.7	964.3	1 110.2	1 472.7	1 368.0	1 743.9	1 813.8	1 706.4	12 354.1

CAPITAL EXPENDITURE FORECAST (CEF10)

(in millions of dollars)

	Total Project Cost	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	10 Year Total
Power Supply												
HVDC Converter Transformer Bushing Replacement	5.9	0.4	0.7	1.1	-	-	-	-	-	-	-	2.2
HVDC Auxiliary Power Supply Upgrades	5.3	0.9	0.2	-	-	-	-	-	-	-	-	1.2
Dorsey Synchronous Condenser Refurbishment	32.3	2.5	4.5	4.4	1.1	-	-	-	-	-	-	12.5
HVDC System Transformer & Reactor Fire Protection & Prevention	10.4	1.0	0.6	0.2	-	-	-	-	-	-	-	1.8
HVDC AC Filter PCB Capacitor Replacement	29.8	1.2	-	-	-	-	-	-	-	-	-	1.2
HVDC Transformer Replacement Program	105.7	0.3	1.1	4.9	8.1	-	-	-	-	-	-	14.5
Dorsey 230 kV Relay Building Upgrade	82.2	4.4	3.7	3.4	17.5	35.4	12.3	3.2	-	-	-	79.8
HVDC Stations Ground Grid Refurbishment	4.3	0.5	0.4	0.4	0.4	0.3	0.1	-	-	-	-	2.2
HVDC Circuit Breaker Operating Mechanism Replacement	15.9	1.9	2.7	1.1	0.4	0.1	0.1	0.1	0.1	0.1	-	6.6
HVDC Bipole 1 Pole Differential Protection	3.3	-	-	1.1	2.2	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.5	2.5	3.9	11.0	2.1	-	-	-	-	-	19.9
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.9	2.4	5.7	-	-	-	-	-	11.0
HVDC Bipole 1 & 2 Smoothing Reactor Replacement	39.3	14.3	12.8	1.9	9.2	-	-	-	-	-	-	38.2
HVDC Bipole 1 P1 & P2 Battery Bank Separation	3.2	-	0.9	2.2	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	-	0.5	1.6	1.1	3.0	3.1	2.3	-	-	-	11.7
HVDC Bipole 1 & 2 DC Converter Transformer Bushing Replacements	8.7	-	0.6	1.0	1.7	5.4	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Hall Wall Bushing Replacements	19.2	0.5	0.1	0.2	3.4	4.4	4.1	4.8	1.4	-	-	18.9
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.3	0.9	1.5	1.1	1.1	0.3	-	-	-	5.2
HVDC Bipole 2 Refurbish Thyristor Module Cooling Components	4.7	1.4	1.3	-	-	-	-	-	-	-	-	2.7
HVDC Transformer Marshalling Kiosk Replacement	6.8	0.6	1.8	2.0	1.2	0.7	-	-	-	-	-	6.3
HVDC Gapped Arrestor Replacement	16.3	0.1	3.8	3.4	4.0	3.5	1.3	0.2	-	-	-	16.3
Pine Falls Rehabilitation	56.2	2.5	5.8	15.8	1.2	4.6	6.8	9.0	-	-	-	45.8
Jenpeg Unit Overhauls	128.1	-	-	-	-	-	2.3	2.5	18.5	24.3	24.9	72.5
Power Supply Dam Safety Upgrades	34.0	4.3	-	-	-	-	-	-	-	-	-	4.3
Winnipeg River Riverbank Protection Program	19.7	1.2	1.2	1.3	1.3	1.3	1.3	1.4	-	-	-	9.1
Power Supply Hydraulic Controls	20.5	3.7	1.5	0.5	1.3	-	-	-	2.1	2.6	0.9	12.6
Slave Falls Rehabilitation	223.0	19.8	7.3	1.7	3.7	32.4	40.8	45.6	38.8	9.2	-	199.4
Great Falls Unit 4 Overhaul	19.7	4.5	9.5	-	-	-	-	-	-	-	-	14.0
Great Falls Unit 5 Discharge Ring Replacement and Major Overhaul	24.8	-	-	-	-	2.3	17.5	5.0	-	-	-	24.8
Generation South Transformer Refurbish & Spares	29.8	0.4	4.8	11.3	12.1	0.5	0.3	0.3	-	-	-	29.7
Water Licenses & Renewals	40.8	5.3	6.0	6.2	6.8	6.6	0.7	-	-	-	-	31.5
Generation South PCB Regulation Compliance	4.7	0.6	0.5	0.4	0.4	0.2	2.4	-	-	-	-	4.5
Kettle Transformer Replacement Program	35.6	8.7	7.0	7.2	8.0	3.9	-	-	-	-	-	34.8
Generation South Breaker Replacement Program	11.1	2.5	3.0	1.4	3.4	-	-	-	-	-	-	10.3
Seven Sisters Upgrades	9.5	2.8	2.0	1.5	1.2	-	-	-	-	-	-	7.6
Generation South Excitation Program	18.3	0.1	0.3	2.1	2.4	0.6	1.5	2.9	1.7	6.8	-	18.3
Brandon Unit 5 License Review	18.7	0.2	0.1	1.6	2.7	9.2	-	-	-	-	-	13.8
Selkirk Enhancements	14.2	1.5	0.4	-	-	-	-	-	-	-	-	1.9
Laurie River/CRD Communications & Annunciation Upgrades	4.8	0.9	3.1	0.7	-	-	-	-	-	-	-	4.6
Notigi Marine Vessel Replacement & Infrastructure Improvements	4.6	0.9	3.0	0.6	-	-	-	-	-	-	-	4.5
Pointe du Bois Safety Upgrades	50.0	0.5	1.6	5.5	11.2	16.0	11.7	3.5	-	-	-	50.0
Fire Protection Projects - HVDC	5.2	0.6	0.4	0.3	1.2	1.0	-	-	-	-	-	3.5
Halon Replacement Project	36.4	4.6	5.5	6.8	2.7	-	-	-	-	-	-	19.7

PUB ORDER NO. 150/08

DIRECTIVE NO. 4

INDEPENDENT ASSESSMENT OF FIXED VS. FLOATING RATE DEBT

Manitoba Hydro

July 24, 2009

5. TECHNICAL ANALYSIS

The purpose of NBF's technical analysis was to quantify the volatility and correlation of the key factors identified in Section 3, namely domestic utility rates, export power prices (short-term contracts/spot transactions and long-term contracts) and Canadian and US short-term interest rates. NBF found that the difference in volatilities between regulated and spot electricity prices and their correlation to short-term interest rates were the key elements of this analysis. The results were then used as inputs for the scenario analysis in Section 6.

5.1. ASSUMPTIONS

In order to strictly adhere to the scope of this mandate and issue in question, namely the optimal mix of fixed vs. floating rate debt, NBF has made the following assumptions in its technical analysis.

5.1.1. US Assets and Liabilities

The NBF methodology assumed Manitoba Hydro's current mix of Canadian and US Dollar ("USD") denominated debt as given, and then analyzed the optimal mix of fixed vs. floating rate debt for its entire debt portfolio.

Manitoba Hydro currently has an EMP to manage its currency risk. The EMP uses USD denominated debt to establish a natural hedge between USD cash inflows and outflows. Any discussion regarding the appropriate mix of Canadian vs. USD denominated debt instruments would entail an evaluation of Manitoba Hydro's currency risk hedging practices, which is outside the scope of this assignment.

For the purposes of the technical analysis, NBF assumed that USD denominated debt accounted for 37% of the total debt portfolio in the base case year, calculated as the average proportion of total debt over the last three years. This proportion is comparable to the 37% in extraprovincial revenues as a percentage of Manitoba Hydro's total electric revenue as identified in Table 6.

Table 9: Historical Proportion of US Dollar Denominated Debt[28]

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Exchange Rate (C$/US$)	$1.172	$1.174	$1.594	$1.469	$1.311	$1.210	$1.167	$1.153	$1.028
Fixed Debt (C$mm)	$3,367	$2,758	$4,033	$3,425	$2,793	$2,578	$2,488	$2,458	$2,191
Floating Rate Debt (C$mm)	$206	$176	$478	$441	$393	$363	$350	$346	$514
Total US Debt (C$mm)	$3,573	$2,934	$4,511	$3,866	$3,186	$2,940	$2,838	$2,804	$2,705
(%) of Total Debt	50.1%	45.5%	58.9%	53.2%	43.1%	40.8%	39.6%	38.8%	35.6%

5.1.2. Debt Maturity Schedule

Discussion regarding the maturity schedule of debt instruments is outside the scope of this assignment. Hence, current and historical maturities will form the basis for the technical analysis.

As Manitoba Hydro's weighted average fixed term to maturity in 2008 was 14.7 years, throughout its technical analysis, NBF assumes a fixed term to maturity of 15 years for fixed debt instruments.

Table 10: Historical Average Maturity Terms[29]

Term to Maturity	2000	2001	2002	2003	2004	2005	2006	2007	2008
Total Canada	23.2	21.9	21.1	20.7	19.4	18.9	18.8	18.1	19.4
Total US	18.2	15.6	13.5	12.4	12.3	11.3	10.3	10.3	8.8
Total Fixed	18.7	17.3	15.9	15.6	14.9	14.6	14.4	13.7	14.7
Total Floating	13.0	12.7	9.4	8.3	7.8	8.0	7.1	7.8	6.4

5.2. VOLATILITY AND CORRELATION ANALYSIS

As previously discussed, Manitoba Hydro's financial results are subject to several volatility factors, most notably variances in export electricity prices, exchange rates and hydrology. The primary source of net income variability relates to the substantial level of hydrology risk that is present in Manitoba Hydro's operations. Given that in principle there is no causal relationship between weather patterns and macroeconomic indicators, it is not possible to lower exposure to this hydrology risk through determining a debt policy.

However, it is important to note that the added volatility introduced by fluctuations in hydrology does highlight the need for the stabilization of income, to the extent that it can be managed through financial instruments.

[28] Data as per Manitoba Hydro.
[29] Data as per Manitoba Hydro.

Given that hydrology and currency risks are non-factors in the technical component of the analysis, NBF's methodology focuses on power prices in both the domestic and extraprovincial markets as value drivers for the assets, and compares them to the liability portion driven by short-term interest rates. As a proxy for volatility in domestic rates and long-term export contracts, NBF's technical analysis utilizes the volatility in the Canadian Consumer Price Index ("Canadian CPI") and US Consumer Price Index ("US CPI"), respectively.

The historical results, based on a 2005-2009 period, are summarized as follows:

Table 11: Variable Volatilities, 2005-2009[30]

	Asset Variables	Volatility Metric	Mean	Standard Deviation
A	**Domestic Utility Rates**	Change in Canadian CPI	1.68%	1.45%
B	**Extraprovincial Power (Short-Term Contracts and Spot)**	MISO Power Price	US$42.37	US$11.96
C	**Extraprovincial Power (Long-Term Contracts)**	Change in US CPI	2.32%	1.66%

	Liability Variables	Volatility Metric	Mean	Standard Deviation
D	**Canadian Short-Term Interest Rates**	3 Month BA	3.49%	1.18%
E	**US Short Term-Interest Rates**	3 Month LIBOR	4.02%	1.43%

Changes in Canadian CPI and US CPI levels were measured using a lognormal distribution. The mean reflects annualized increases, whereas the standard deviation represents the proportion of the mean that is subject to volatility on an annualized basis.

Table 12: Variable Correlation Matrix, 2005-2009

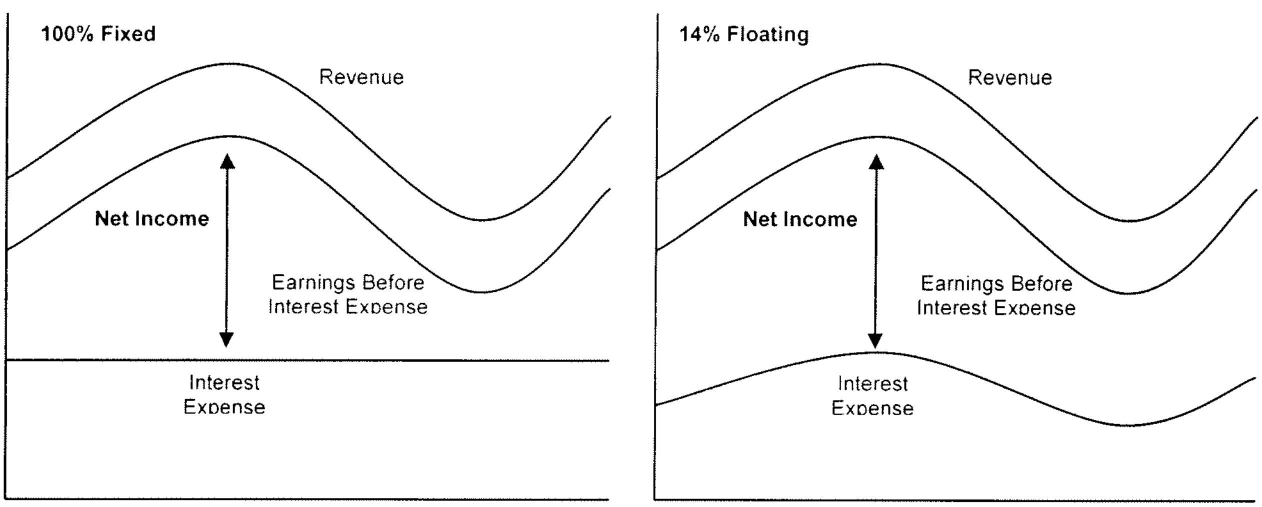
Correlations	Domestic Utility Rates	Export Power (ST and Spot)	Export Power (LT Contracts)	Canadian ST Interest Rates	US ST Interest Rates
Domestic Utility Rates	-	0.17	0.66	0.06	0.00
Extraprovincial Power (ST and Spot)	0.17	-	0.23	0.46	0.37
Extraprovincial Power (LT Contracts)	0.66	0.23	-	0.22	0.00
Canadian ST Interest Rates	0.06	0.46	0.22	-	0.91
US ST Interest Rates	0.00	0.37	0.19	0.91	-

[30] Historical interest rate data as per Bloomberg.

The technical analysis demonstrates that short-term export power contract prices have higher correlation with short-term interest rates than domestic rates and long-term export contracts. The results suggest that the volatility in the pricing of these contracts could be better mitigated by increasing the proportion of floating rate debt.

Increasing the proportion of floating rate debt can lead to lower risk because our analysis shows that interest expense and revenues are correlated. Because short term interest expense and revenues move together to a certain extent, net income can be stabilized by adding a floating element to the overall debt portfolio. A 100% fixed portfolio would keep interest expense flat, and hence revenue fluctuations will be reflected in net income. However, by allowing interest expense to move together with revenue, Manitoba Hydro can achieve more net income stability, as shown in figure 9.

Figure 9: Correlation Impact on Net Income



This conclusion was incorporated in the scenario analysis portion of NBF's assessment.

6. SCENARIO ANALYSIS

Based on the aforementioned technical analysis, NBF's scenario analysis generated a set of 10,000 scenarios for each of the identified key factors. These scenarios reflected the volatility and correlation metrics previously quantified in the technical analysis.

This set of scenarios was then applied to 100 portfolios of different fixed vs. floating rate debt mixes. Under each scenario, the net impact on Manitoba Hydro's net income was calculated for each portfolio mix. The inherent volatility in a given portfolio selection was then derived from the variance that each fixed vs. floating rate debt mix caused under each one of the 10,000 generated scenarios.

The product of this scenario generation process was an average return (defined as net income impact) and risk (the level of volatility of this net income impact) that resulted from each one of the 100 different portfolio mixes.

6.1. Efficient Frontier

Each portfolio was plotted according to its risk and reward profile, yielding a curve of possible outcomes. Due to the positive correlation between power prices (especially short-term and spot export prices) and floating interest rates, the result suggested that risk could actually be lowered by increasing the proportion of floating rate debt.

The fixed equivalent, defined as the portfolio that yields the same level of risk as the 100% fixed portfolio, consisted of 27% floating rate debt. For illustration purposes, this was established as the base case level of risk and return, and each portfolio's net income impact and volatility were calculated relative to this base case.

Table 13 summarizes these findings:

Table 13: Portfolio Risk/Return Matrix

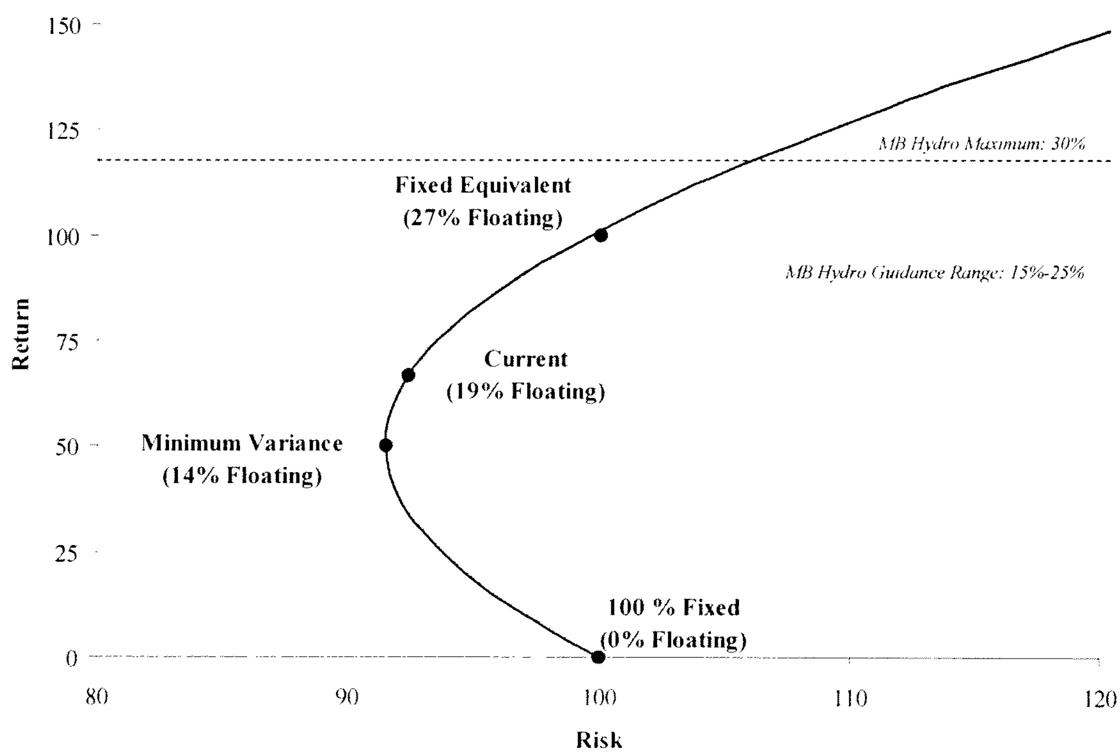
	Floating (%)	Adjusted Risk	Adjusted Return
1. Fixed	0%	100	0
2. Minimum Variance	14%	93	50
3. Current (March 31, 2008)	19%	94	69
4. Fixed Equivalent	27%	100	100
5. Floating	100%	253	370

The minimum variance portfolio was defined as the fixed vs. floating rate mix that yielded the lowest variance in net income, and was achieved by incorporating 14% floating rate debt into the debt portfolio. The above analysis implied that risk could be lowered by 7% by increasing the floating rate debt mix to 14% (from a 100% fixed portfolio) while making positive gains in net income since floating interest rates tend to be lower than fixed interest rates.

Furthermore, this analysis demonstrated that in order to maximize returns for a given level of risk, the portfolio must contain more than 14% floating rate debt. This minimum variance point therefore determined the beginning of the efficient frontier, which was defined as the set of portfolios that maximize return for a given level of risk.

The efficient frontier resulting from this scenario analysis is illustrated as follows:

Figure 10: Volatility Impact Model Efficient Frontier



This analysis proves that Manitoba Hydro's guidance range of 15% to 25% floating rate debt mix is efficient from a risk/return perspective as it is above the minimum variance portfolio. In addition, this range is below the fixed equivalent mix of 27% floating rate debt. As a result, Manitoba Hydro's current floating rate debt policy has the effect of lowering net income volatility in relation to a 100% fixed debt portfolio, while increasing returns through interest cost savings.

8. IMPACT ANALYSIS

Having established an optimal range of fixed vs. floating rate debt mix, as prescribed by the asset/liability framework, NBF analyzed the retroactive impact of this range on Manitoba Hydro's historical financial results.

8.1. IMPACT ON MANITOBA HYDRO

For each year, NBF calculated the impact on interest expense resulting from both the minimum variance (14% floating rate debt) and fixed equivalent (27% floating rate debt) portfolios. This allowed for an adjustment to the actual net income and coverage ratios. These impacts are summarized as follows:

Table 14: Impact of changes in Floating Rate Debt Mix[33]

all figures in ($mm)	2000	2001	2002	2003	2004	2005	2006	2007	2008
Total Debt	**$7,134**	**$6,442**	**$7,661**	**$7,268**	**$7,390**	**$7,204**	**$7,169**	**$7,227**	**$7,599**
Historical Debt Mix									
Floating Rate	15%	14%	14%	16%	17%	22%	19%	19%	19%
Net Income									
Minimum Variance	$152	$267	$206	$61	($453)	$129	$410	$116	$326
Actual	$152	$269	$214	$71	($436)	$136	$415	$122	$346
Fixed Equivalent	$171	$301	$229	$93	($424)	$149	$424	$133	$363
Interest Coverage									
Minimum Variance	1.35	1.62	1.41	1.12	0.14	1.24	1.76	1.22	1.67
Actual	1.35	1.62	1.42	1.14	0.17	1.25	1.77	1.23	1.71
Fixed Equivalent	1.39	1.69	1.45	1.18	0.19	1.27	1.79	1.25	1.75

8.2. CONCLUSION

The impact analysis demonstrates that since Manitoba Hydro's historical floating rate debt mix had stayed within the optimal range as prescribed by the asset/liability framework, the actual financial results were also within the optimal range.

[33] Historical financial data as per Manitoba Hydro.

<u>**CAC/MSOS/MH I-164**</u>

Subject: **Debt and Debt Management Fixed vs. Floating**

Reference: **Independent Assessment of Corporate Policy Fixed vs. Floating, the National Bank Financial Report, Appendix 13.3, Section 8.1, Impact on Manitoba Hydro, page 39.**

The report provides a table showing impact of changes on the floating rate debt mix.

Data from 2008 Table 14		(millions)		
2008 Total Debt		$7,599	Net	Interest
	Floating		Income	Saving
Fixed Equivalent	27%	$2,052	$ 363	
Minimum Variance	14%	$1,064	$ 329	
Difference		$ 988	$ 34	3.44%

The Table above is prepared to permit a discussion of the impact of changes, and assumes for the purpose of these questions that the $7,559 million total debt number is an average debt number, that the net income is unaffected by tax, and that the Fixed Equivalent and Minimum Variance calculations are not rounded.

CAC/MSOS wishes to better understand this analysis,

a) Would we be correct in thinking that the difference between the modeled Fixed Equivalent and Minimum Variance floating rate debt amounts is $988 million?

<u>**ANSWER**</u>**:**

The following response was provided by National Bank Financial:

"The following information was utilized to respond to the question:

Table 14: Impact of changes in Floating Rate Debt Mix[1]

all figures in ($mm)	2000	2001	2002	2003	2004	2005	2006	2007	2008
Total Debt	**$6,609**	**$6,489**	**$7,841**	**$7,396**	**$7,484**	**$7,263**	**$7,169**	**$7,375**	**$7,599**
Historical Debt Mix									
Floating Rate	18%	15%	18%	18%	22%	19%	17%	19%	20%
Net Income									
Minimum Variance	$144	$268	$205	$62	($461)	$123	$412	$117	$333
Actual	$152	$270	$214	$71	($436)	$136	$415	$122	$346
Fixed Equivalent	$158	$277	$246	$98	($418)	$159	$424	$128	$358
Interest Coverage									
Minimum Variance	1.33	1.62	1.40	1.12	0.12	1.23	1.76	1.22	1.67
Actual	1.35	1.62	1.42	1.14	0.17	1.25	1.77	1.23	1.69
Fixed Equivalent	1.36	1.64	1.48	1.19	0.20	1.29	1.79	1.24	1.72

The difference in floating rate debt between Fixed Equivalent and Minimum Variance portfolios would have been approximately $988 million."

[1] Historical Manitoba Hydro data revised as per company information. This adjustment is for consistency purposes only and does not affect NBF's findings in the report.

MANITOBA HYDRO
2010/11 & 2011/12 GENERAL RATE APPLICATION

INTEGRATED FINANCIAL FORECAST & ECONOMIC OUTLOOK

INDEX

Due to uncertainty pertaining to the current economic situation key short term variables including escalation, interest rates and exchange rates impacting the IFF were reviewed in summer 2009 to ensure that current information was considered in the forecast.

The value of the Canadian dollar continued to exhibit volatility relative to the US dollar throughout the summer of 2009. The Canadian dollar averaged $1.26 in March 2009, $1.12 in July 2009 and further appreciated to reach $1.02 in mid-October 2009. The value of the Canadian dollar had appreciated over the summer due, in large part, to the US dollar depreciating relative to other currencies in response to ongoing concerns with U.S. trade and budgetary deficits. Due to this volatility, forecasts of exchange and interest rates were reviewed again in October 2009 to ensure the most current information was reflected in the IFF. The Manitoba Hydro short term and long term cost of debt, shown in the table below, incorporates the relevant credit spread and the provincial guarantee fee. As a result of these subsequent reviews, the values of certain variables that were used in the IFF differ from those in the 2009 Economic Outlook. The revised variables are as follows:

		Short-Term Interest Rate		**Long-Term Interest Rate**		
	CPI % change	**T- Bill %**	**MH Cost of Debt %**	**10 Yr+ %**	**MH Cost of Debt %**	**Cdn$/US$**
2009/10	0.6	0.25	1.45	3.70	5.60	1.11
2010/11	1.9	1.20	2.40	4.00	5.65	1.07
2011/12	2.0*	3.40	4.60	4.60	6.20	1.09
2012/13	2.0*	4.10	5.30	5.10	6.70	1.07

*Note: CPI was unchanged from 2009 Economic Outlook for 2011/12 and 2012/13.

5.2 INTEGRATED FINANCIAL FORECAST

The Integrated Financial Forecast IFF09-1 sets forth the projected financial results and financial position of Manitoba Hydro. Its purpose is to provide an indication of the Corporation's long-term financial direction and for use in sensitivity analysis evaluating strategic alternatives. The forecast IFF09-1 can be found in Appendix 5.2.

This year's IFF reflects the impacts of the economic downturn on short-term financial results and the consequential impacts over the 10-year forecast period. A comparison of MH09-1 with MH08-1 in Table 5.1.1 shows a significant decline in net income due

PUB-Pre-Asks

Re: IFF 10

e) Please provide a comparison of the interest rate (IFF 10 versus IFF 09-1).

The interest rate assumptions are the same as those contained in IFF10. The table below outlines the interest rate assumptions (IFF09 is in brackets):

	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *
2010/11	1.10% (1.40%)	4.20% (4.65%)
2011/12	2.10% (3.60%)	4.35% (5.20%)
2012/13	3.30% (4.30%)	5.25% (5.70%)
2013/14	3.85% (4.45%)	5.55% (6.10%)
2014/15	4.30% (4.45%)	5.90% (6.10%)
2015/16	4.65% (4.45%)	6.30% (6.10%)
2016/17 – 2029/30	4.65% (4.45%)	6.60% (6.10%)

*Excluding Provincial Guarantee Fee of 1.0%

PUB/MH I-35

Subject: **Tab 4: Financial Results & Forecast**
Reference: **Tab 4 Page 16 of 29, Schedule 4.6.0 Finance Expense**

e) Please provide a schedule of new debt issues of long-term borrowings for the years 2009/10, 2010/11 and 2011/12 years and the forecast and Interest per year at forecast rate interest rates used for each loan.

ANSWER:

Please see the attached schedule.

New Long Term Debt Issues
Forecast as at September 30, 2009 in Schedule 4.6.0 Interest Costs
(all amounts in $millions)
(rates exclude PGF)

Fiscal Year	Series	Amount	Currency	Issue Date	Maturity Date	Coupon Rate	Interest Cost 2009/10	Interest Cost 2010/11	Interest Cost 2011/12
2009/10	C107	100.0	CAD	2-Jun-2009	4-Sep-2012	Floating 3 BA + 0.40%	0.7	1.6	3.6
	FK-2	300.0	CAD	5-Jun-2009	5-Mar-2040	4.65%	11.6	14.0	14.0
	FM-4	100.0	CAD	1-Sep-2009	1-Sep-2014	Floating 3 BA + 0.484%	0.6	1.8	3.7
	Forecast	200.0	CAD	Feb-2010	Feb-2040	4.60%	0.8	9.2	9.2
	Forecast	200.0	CAD	Mar-2010	Mar-2040	4.60%	0.0	9.2	9.2
	Total New Debt	900.0					13.7	35.8	39.7
2010/11	Forecast	200.0	CAD	Jun-2010	Jun-2040	4.65%		7.0	9.3
	Forecast	200.0	CAD	Aug-2010	Aug-2040	4.65%		5.4	9.3
	Forecast	200.0	CAD	Nov-2010	Nov-2040	4.65%		3.1	9.3
	Forecast	200.0	CAD	Mar-2011	Mar-2041	4.65%		0.0	9.3
	Total New Debt	800.0						15.5	37.2
2011/12	Forecast	200.0	CAD	Sep-2011	Sep-2041	5.20%			5.2
	Forecast	200.0	CAD	Dec-2012	Dec-2042	5.20%			2.6
	Forecast	200.0	CAD	Mar-2012	Mar-2042	5.20%			0.0
	Total New Debt	600.0							7.8

Leveraging Network Utility Asset Management Practices for Regulatory Purposes

November 2009

KEMA

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