MANITOBA HYDRO
2010-2011 GENERAL RATE APPLICATION

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

BOOK OF DOCUMENTS

Kubursi/Magee Cross Examination

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TABLE OF CONTENTS

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PUB/KM-8.
Reference: Section 1.4, Page 19 — System Expansion

Eleventh. 'System expansion is necessary and massive capital will be needed sooner or later to meet the expanding load in Manitoba...."

a) Please provide the specific load forecast and power resource references that support the conclusions in the eleventh finding.

b) Please clarify how this statement is impacted by:
Economic downturn to 2009 and 2010.
A drop in MH's domestic load of 1,000 to 1,500 GWh/year after 2008.
A weak electricity export market over the last two years.
A possible continuation of low natural gas prices.
A stalled C02 pricing process.

ANSWER:

a) The issue is timing of these investments. Sooner or later, Manitoba demand would catch up to existing capacity. This present cannot be projected forward. There are a number of special events that would not hold for long. These include the present sluggish recovery in the US and to some extent in Canada. Consensus forecasts have marked 2014 as the beginning of a major recovery. The present is also witness to a major decline in natural gas prices. Shale gas has generated an excess supply of gas. Its impact on water and other technical and environmental considerations are being cited as reasons why this excess supply cannot be expected to last for long period. Carbon taxes are very low and a few measures needed to combat global warming and climate change are being shelved. There is no evidence, however, that this reticence and slow response to climate change can be expected to remain in place. The reversal of economic trends by themselves should anchor a healthy and steady rise in electricity demands. When this aided by weather changes and extreme events, the combination would translate into higher and higher demands. Environmental considerations would have limited volumetric impacts given their slow and gradual manifestations but could have serious implications for prices.

b) i) The current economic slowdown has reduced energy demand particularly by industry. This cannot be expected to last beyond 2014 and a few economists and organizations (IMF and OECD) have even projected that recovery would start in 2011 and would take a firm hold by 2014.

ii) A drop of MH load is again a reflection of a poor economic recovery. This recovery is expected to strengthen in the next few years.

iii) Weak electricity exports are also the result of poor economic conditions in the US and could also be the result of implicit protectionism and buying American. If it is the result of the former, then the expected economic recovery would change the outlook. If it is the latter the rebound in the export market may be delayed but not reversed.

iv) Natural gas prices are low because of sluggish demand for electricity and because of abundant gas supplies on account of shale gas. The water requirements and quality of water impingements could easily slow this reliance on shale gas and natural gas prices could start rising.

v) The stalled CO_2 process is worrisome; it affects prices more than quantities but could reduce profitability of any new investment in generation.

The critical factor is again are the costs and timing of the investment in capacity expansion. History has taught us not to exaggerate the present; it is not the best indicator of the future, particularly of the present is encumbered.

3

CAC/MSOS Exhibit #____

CAC/MSOS/KM/PRE-ASK-1
Attachment 1

Climatic Change
DOI 10.1007/s10584-011-0061-5

LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

Robert W. Howarth · Renee Santoro · Anthony Ingraffea

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Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the lifetime of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years. A

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010). B

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

6

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a]Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b]Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c]Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d]Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e]Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

10

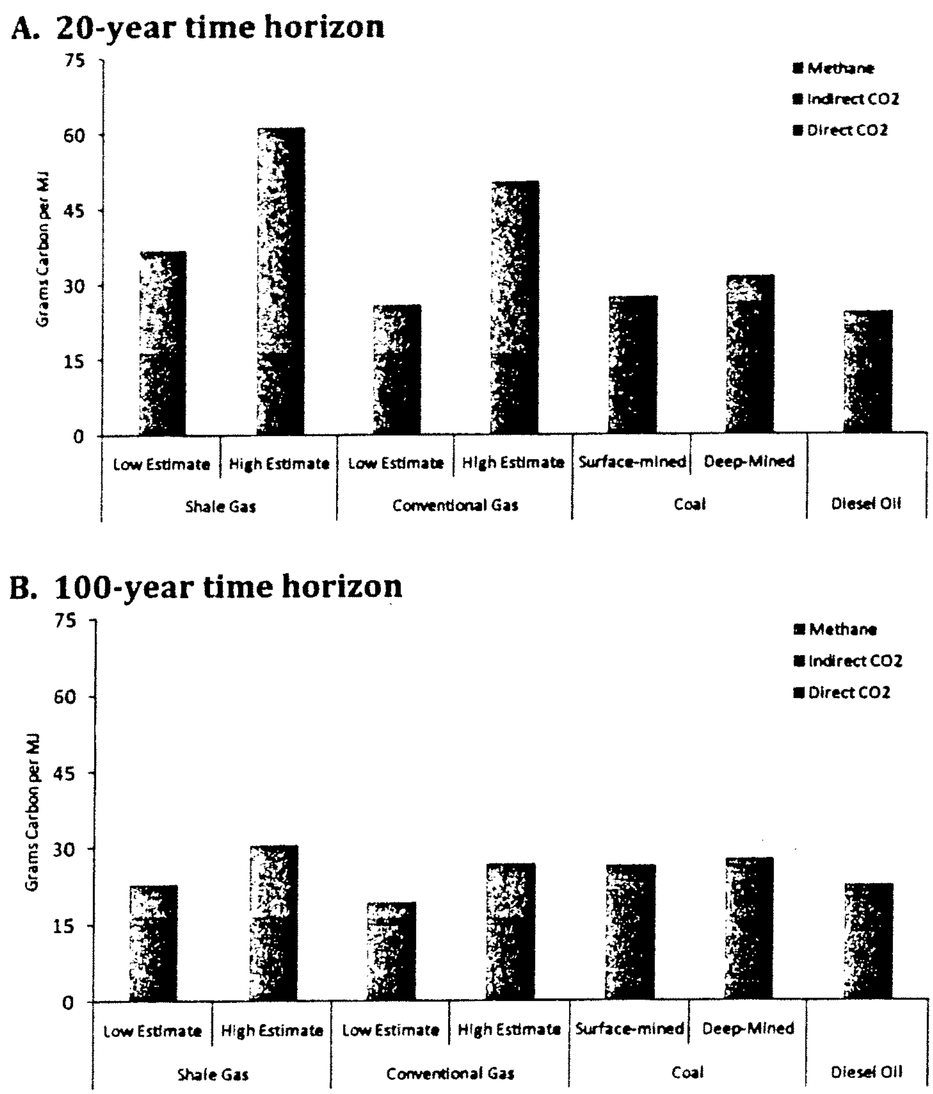

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil. C

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming. D

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change. E

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CAC/MSOS/KM-11

Subject: Risk

Reference: Kubursi Magee Report, page 6

Preamble: The Report states:

> MH tolerance and acceptance of risks may be different from that of the public.

Question:

a) Please advise on Kubursi's and Magee's understanding of whether the risk tolerance at MH is, in fact, different from that of the public.

b) Please advise how Kubursi and Magee would assess the relative risk tolerance of MH versus the risk tolerance of the public.

ANSWER:

a) As long as there is not an explicit formula that ties rate setting to net earnings of MH, and the residents of Manitoba do not have a mechanism whereby they can influence the distribution of MH's net earnings, the increased earnings from selling electricity at times when a risk exists that water flows may decline means that the rewards of risk taking by MH are reflected in higher earnings for MH.

These additional earnings may not be shared with the rate payers. The latter, however, have to bear some of these losses as increases in the rates and/or as tax payers if losses are covered by debt.

b) This diversion of risk and rewards between the public and MH creates a wedge and reveals a difference in the interest and appreciation of risk between the two parties.

CHAPTER I INTRODUCTION:
PUB/KM-2.

Reference: Risk Tolerance Page 6, paragraph 3

KM refers to misalignment of risk tolerance between MH and Manitoba public.

a) Describe the characteristics of risk appetite at MH that are different from public risk appetite.

b) Explain the statement the "potential rewards of the risk-taking are internalized within MH?

c) What process is available to ensure the "shareholder" (ie the citizens of Manitoba) is not subject to undue risks or costs from Manitoba Hydro actions and that Manitoba Hydro's management of risk is appropriate?

ANSWER:

(a) The public is typically risk averse and would have little appetite for risk taking. This is not typically the case for utilities and businesses that generally have different assessment of risks, even when they are inclined to be conservative. MH has generally a greater appetite for risk taking than the public; the last drought is a case in point. MH may feel less inclined to stop selling electricity at the early part of a possible drought as precipitation declines in the spring, fearing that refraining from selling electricity at this early stage may represent forgone revenues if the precipitation levels were to change. The public may not have the same evaluation of these forgone earnings; they are not likely to see any change in their rates on their account; the rate setting in Manitoba is not explicitly sensitive to these earnings.

(b) As long as there is not explicit formula that ties rate setting to net earnings of MH and the residents of Manitoba do not have a mechanism whereby they influence the distribution of MH net earnings, the increased earnings from selling electricity at times when a risk exists that water flows may decline means that the rewards of risk taking by MH are reflected in higher earnings for the utility which may not be shared by the rate payers or losses that the rate payers and/or tax payers may have to shoulder.

(c) A risk management plan consistent with best practice in other hydro utilities and best risk management principles of the type described at length in Chapter 2 of the KM Report would help align the risk management plan and risk governance with shareholder expectations. The public would like to see their Corporation is fully aware of expected risks, their consequences, their probability of occurrence and have in place risk mitigation and control plans to deal with them. MH has an evolving risk management plan that is more consistent with best practice, but that there are a few adjustments and improvements that can be put in place to make it more consistent with expectations and best practice standards. A few of these recommendations have been outlined at length in KM Report Chapter 2 and Chapter 7.

MH/KM - 3

Reference: Chapter 1 - Page 5

"The public guarantees of debt can tempt a public utility to undervalue risk and behave more recklessly than if it were to bear alone the consequences of its risky behaviour."

a) Please indicate whether the above statement is included as a direct reference to MH or as an academic statement regarding utilities generally.

b) If the response in part a) is that the statement was a direct reference to MH, please provide studies, references and/or documents supporting this statement as it applies to MH.

ANSWER:

(a) The statement is not a direct reference to Manitoba Hydro. It is typical of any business. It does apply equally to Manitoba Hydro and to any other public utility. As noted, the connotation must be guarded against.

(b) Manitoba Hydro in early 2003 felt it was not in a position to reduce the selling of power in the US market. This constituted a risk adoption to maintain income.

MH/KM - 5

Reference: Chapter 1 - Page 6

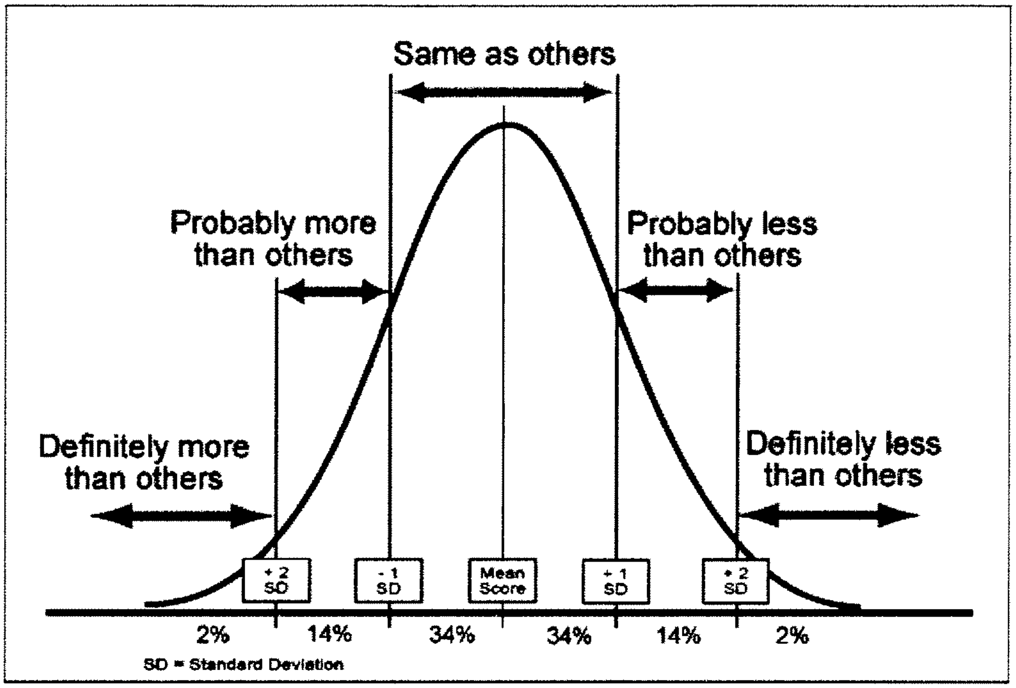
"This misalignment in risk tolerance arises not only because of different appetites for risk but also from the fact that the public assumes the costs of any losses either in higher electricity rates (if PUB allows it) or through debt payment charges, whereas the potential rewards of the risk-taking are internalized within MH."

a) Given MH's definition of revenue requirement for the purpose of rate making (where export and other revenues are applied to reduce revenue requirement from domestic customers), please explain how the rewards of the risk taking are internalized within MH.

ANSWER:

As long as there is not an explicit formula that ties rate setting to net earnings of MH and the residents of Manitoba do not have a mechanism whereby they can influence the distribution of MH's net earnings, the increased earnings from selling electricity at times when a risk exists that water flows may decline means that the rewards of risk taking by MH are reflected in higher earnings for MH which may not be shared by the rate payers of losses that the rate payers and/or tax payers may have to shoulder.

NORMAL DISTRIBUTION GRAPH



21

CAC/MSOS Exhibit #____

PUB ORDER NO. 150/08

DIRECTIVE NO. 4

INDEPENDENT ASSESSMENT OF FIXED VS. FLOATING RATE DEBT

Manitoba Hydro

July 24, 2009

Manitoba Hydro
Independent Assessment of Fixed Vs. Floating Rate Debt

Introduction

Order 150/08, Directive No. 4 directed MH to undertake the following:

> MH to provide the Board an independent assessment of the Corporation's relative weighting of fixed vs. floating debt and file a report with the Board on or before June 30, 2009.

Manitoba Hydro response

A Request for Tender was sent to six financial institutions. The low bid was received from National Bank Financial (NBF) in the amount of $200 000.

In summary, NBF concluded that, "Manitoba Hydro's fixed vs. floating rate debt policy of 15% to 25% floating rate debt is inside of the identified optimal range of 14% to 27% floating rate debt, and is therefore both reasonable and appropriate in the context of an asset/liability management framework."

A copy of the NBF Report entitled, "Independent Assessment of Corporate Policy Fixed vs. Floating Rate Debt" is attached.

Attachment
2009 07 24

23

Manitoba Hydro

Independent Assessment of Corporate Policy
Fixed vs. Floating Rate Debt

National Bank Financial

July 16, 2009

NATIONAL BANK FINANCIAL

Table of Contents

List of Figures and Tables

Figures

Tables

1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

It is National Bank Financial Inc.'s ("NBF") understanding that Manitoba Hydro was instructed by the Public Utilities Board of Manitoba ("Board") to obtain an independent assessment of its fixed vs. floating rate debt policy as a result of arguments put forward by a coalition of intervenors in the 2008/09 General Rate Application hearings.

Following a submission in response to a Request for Tender ("RFT") dated January 16, 2009, Manitoba Hydro engaged NBF to provide this independent assessment of its fixed vs. floating rate debt policy.

Although a substantial portion of the data required to complete the assessment was sourced from Manitoba Hydro, NBF worked independently of management and derived its conclusions by way of interpretation of analysis conducted and its institutional knowledge base.

1.2. OBJECTIVE

In order to address the specific requirements outlined in the RFT and complete its independent assessment of Manitoba Hydro's fixed vs. floating rate debt policy, NBF's objective was to provide the following:

1. A body of knowledge regarding the theory of portfolio optimization and advantages and disadvantages of each portfolio optimization methodology;

2. Identification of key factors associated with achieving an optimal weighting of fixed vs. floating rate debt;

3. An in-depth analysis of the fixed vs. floating rate debt policies of Manitoba Hydro's peers;

4. The definition of an optimal floating rate debt range through a variety of scenarios based on different yield curves, interest rate expectations and other factors, that can be supported by historical analysis;

5. An implementation plan to assist Manitoba Hydro on an ongoing basis to ensure its portfolio mix is at an optimal level given different possible economic scenarios; and

6. A financial impact analysis, comparing the optimal fixed vs. floating rate debt mix against Manitoba Hydro's current policy.

NBF has considered and assessed the specific requirements outlined in the RFT and provided an overall recommendation with respect to an optimal fixed vs. floating rate debt policy for Manitoba Hydro, as well as supporting analysis herein.

1.3. ASSUMPTIONS AND LIMITATIONS

NBF's mandate is to provide an independent assessment of Manitoba Hydro's fixed vs. floating rate debt mix. In order to strictly adhere to this mandate, NBF did not evaluate other aspects of Manitoba Hydro's debt policy that may have impacted the result of this assessment. Specifically, NBF's analysis did not include an assessment of Manitoba Hydro's choice of debt maturities and the proportion of US Dollar denominated debt in its debt portfolio, as these issues were deemed to be outside of the scope of this assignment.

In addition, given that Manitoba Hydro's debt is issued and guaranteed by the Province of Manitoba, Manitoba Hydro's cost of debt is dependent on the Province of Manitoba's credit rating. NBF's assessment is therefore premised on the maintenance of the current credit rating of the Province of Manitoba.

1.4. THE NBF APPROACH

In order to assess the situation and recommend an optimal debt policy for Manitoba Hydro, NBF formulated its approach based on a comprehensive analysis of the issues relevant to this assignment. Specifically, the components of the approach were:

1.4.1. Portfolio Theory Overview

NBF began with a comprehensive review of the available academic literature on alternative approaches to fixed vs. floating rate debt management. The review included modern portfolio theory, post modern portfolio theory, market timing and asset/liability management, and their respective advantages and limitations.

In the debt management context, both modern portfolio theory and post modern portfolio theory only seek to minimize a company's cost of debt and its volatility. As a result, these approaches ignore operational cash flow volatility, which may be correlated with movements in interest rates and therefore affect net income. Given that profit is the measure of financial performance, these methods result in incomplete analyses.

The market timing theory also ignores the asset volatility factors of the business and relies on a view on the future direction of interest rates. Furthermore, the framework is unable to quantify the risks associated with issuing floating rate debt; analysis suggests that a debt portfolio with a high proportion of floating rate debt will result in higher interest expense volatility.

The asset/liability approach examines both revenues and expenses simultaneously and formulates an optimal mix of fixed and floating rate debt based on reducing the volatility factors affecting the company. Given that the asset/liability management approach is the only approach that matches a company's assets and liabilities, thereby allowing for optimization of net income, NBF decided that this was the appropriate framework to determine the optimal fixed vs. floating rate debt policy for Manitoba Hydro.

1.4.2. Identification of Key Factors

As the first step in the asset/liability management approach, NBF identified the sources of Manitoba Hydro's cash inflow and outflow volatility. This qualitative process of identifying key factors provided the basis for the quantitative historical analysis of the volatility and correlation of these factors conducted by NBF in its technical analysis.

NBF found that key factors affecting assets were domestic utility rates (subject to Canadian inflation risk) and extraprovincial revenues (primarily subject to US inflation risk for long-term contracts, and fluctuations in spot electricity prices in the MISO grid for short-term contracts and spot transactions).

The key factors affecting liabilities were purchased power (subject to spot electricity prices in the MISO grid), operation and maintenance expenses (subject to Canadian inflation risk), and interest expenses (subject to interest rate fluctuations).

While hydrology is a source of Manitoba Hydro's cash flow volatility, there is no causal relationship between weather patterns and macroeconomic indicators. As a result, it is not possible to lower exposure to hydrology risk through determining a debt policy, and therefore hydrology was not considered a key factor in the asset/liability management framework.

Another source of cash flow volatility excluded from the asset/liability management framework was foreign currency exchange rate fluctuation, which impacts extraprovincial power sales and purchases. Given that Manitoba Hydro already has an Exposure Management Program in place to effectively manage currency risk, evaluation of this risk factor was considered to be outside the scope of this assessment.

1.4.3. Peer Group Analysis

NBF examined the fixed vs. floating rate debt policies of Manitoba Hydro's peer group, which consisted of both crown utility and publicly-traded corporations considered to be vertically integrated electric utilities (i.e. owning energy generation, transmission and distribution infrastructure). The purpose of this analysis was not to provide an assessment of the peer group's fixed vs. floating rate debt policies, but rather to attain insight ~~into a rele~~vant peer group's choice of floating rate debt mix.

The first component of this analysis examined the historical floating rate debt proportions of each of the peers over the past 10 years. When combined with historical yield curves and interest level analyses, NBF found evidence that those peers with a floating rate debt component utilized market timing strategies. In particular, peers tended to increase their portion of floating rate debt during periods of rising term spreads (indicating higher discrepancies between short and long-term interest rates), and lowered the proportion during contracting term spread periods. Moreover, in low interest rate environments this analysis provided evidence that these companies fixed a higher portion of their debt in order to lower their risk at a cheaper cost.

NBF then extended the key factor identification process to the peer group, qualitatively assessing the sources of volatility present in each of the peer group's business models. This analysis yielded a statistically significant correlation between the crown utility peers' proportion of export revenues and their levels of floating rate debt. The analysis demonstrated that Manitoba Hydro's fixed vs. floating rate debt policy was consistent with that of its peer group.

1.4.4. Technical Analysis

A historical analysis was conducted for each of the identified key volatility factors. These factors and their respective volatility metrics were:

Table 1: Key Factor Volatility Metrics

	Asset Variables	Volatility Metric
A	Domestic Utility Rates	Change in Canadian CPI
B	Extraprovincial Power (Short-Term Contracts and Spot)	MISO Power Price
C	Extraprovincial Power (Long-Term Contracts)	Change in US CPI

	Liability Variables	Volatility Metric
D	Canadian Short-Term Interest Rates	3 Month BA
E	US Short Term-Interest Rates	3 Month LIBOR

Each factor's volatility, as measured by the standard deviation from the mean, and its correlation with the other factors, were calculated from historical data.

This analysis proved that short-term export power contracts and spot market sales were the most volatile factors, being driven by power prices in the MISO grid. Also, these factors exhibited higher correlation with short-term interest rates compared to domestic utility rates or long-term export contracts.

As a result, this analysis indicated that Manitoba Hydro's fixed vs. floating rate debt policy should incorporate an element of floating rate debt in order to lower net income volatility under the asset/liability management framework.

1.4.5. Scenario Analysis

Following the results of the technical analysis, a scenario analysis was conducted in order to identify the range of floating rate debt mixes that would lower net income volatility.

NBF's volatility impact model generated 10,000 scenarios, reflecting volatility and correlation metrics derived from the aforementioned technical analysis. Each scenario was then applied to a set of 100 portfolios of varying fixed vs. floating rate debt mixes. The mean net income impact and its volatility, as measured by standard deviation from the mean, were calculated for each one of these 100 different portfolios.

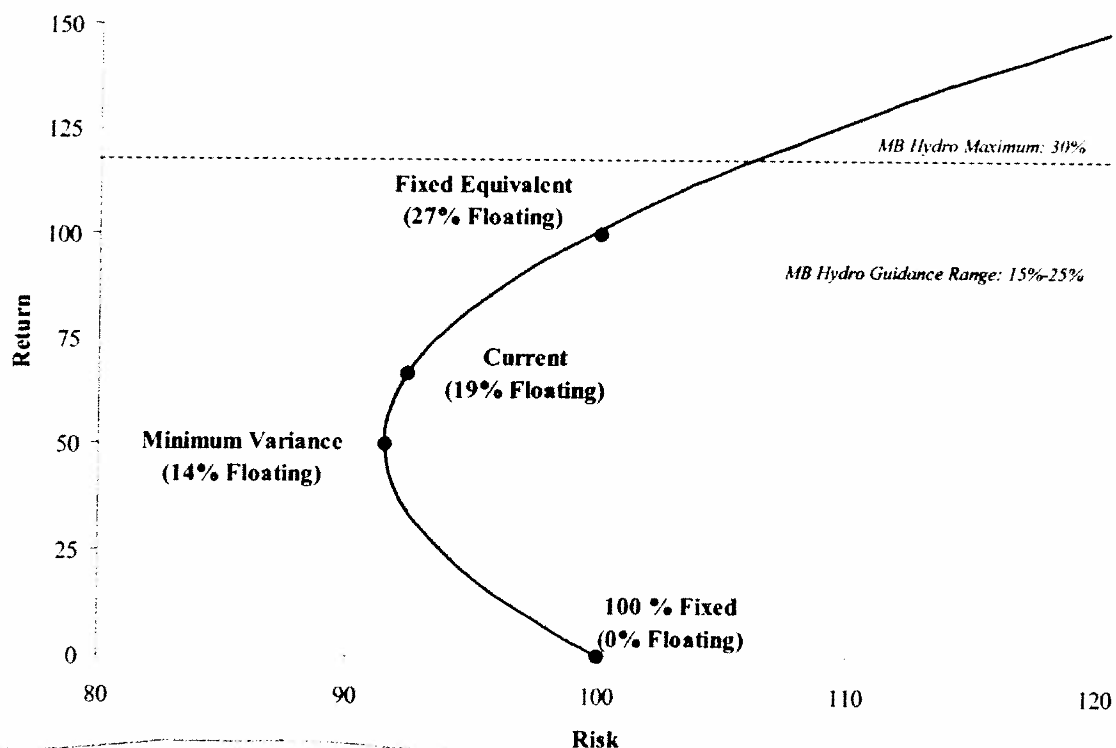
This analysis resulted in the identification of two key metrics: the fixed equivalent and the minimum variance portfolios; The fixed equivalent portfolio, defined as the mix that results in the same amount of volatility as a portfolio comprised of 100% fixed debt, was determined to have a 27% floating rate debt component.

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. Increasing the proportion of floating rate debt can lead to lower risk because the analysis shows that interest expense and revenues are somewhat correlated. The 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.

Table 2: 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

Figure 1: Volatility Impact Model Efficient Frontier



The range between the minimum variance and the fixed equivalent portfolios represents an optimal range of mixes that allow Manitoba Hydro to minimize its interest rate volatility (Risk) and maximize its net income (Return) through lower interest rates, by way of a floating rate component in its debt portfolio.

1.5. Solution Formulation

NBF's scenario analysis demonstrated that Manitoba Hydro's guidance range of 15% to 25% floating rate debt was inside of this optimal floating rate debt range of 14% to 27%.

Having also analyzed the risk profile of Manitoba Hydro's business, namely the high exposure to hydrology risk, NBF believes that Manitoba Hydro's current guidance range is reasonable in the context of an asset/liability management framework, as it seeks to lower risk in an efficient, return maximizing manner.

Furthermore, NBF recommends that Manitoba Hydro complement this asset/liability management framework with a market timing component that allows the company to adjust its floating rate debt proportion within the identified optimal range in order to take advantage of the prevailing interest rate environment. This adjustment should take into account both the level and the slope of the yield curve.

Steeper yield curves generally allow for greater cost savings by switching to floating rate debt, but also result in higher net income volatility. Given that interest rates are currently at historical lows, there exists an opportunity to lower risk at relatively inexpensive levels by increasing the proportion of fixed rate debt.

1.6. Impact Analysis

Having established an optimal range of fixed vs. floating rate debt mixes as prescribed by the asset/liability management framework, NBF analyzed the impact of this range of portfolios on Manitoba Hydro's historical financial results. This analysis demonstrated that historically, Manitoba Hydro has kept its floating rate debt mix within the optimal risk reduction range of 14% to 27%.

1.7. Conclusions

NBF's independent assessment of Manitoba Hydro's fixed vs. floating rate debt policy concludes that its current policy of 15% to 25% floating rate debt is inside of the identified optimal range of 14% to 27% floating rate debt, and is therefore both reasonable and appropriate in the context of an asset/liability management framework.

2. PORTFOLIO THEORY OVERVIEW

In order to determine the appropriate framework for an optimal fixed vs. floating rate policy, NBF conducted a comprehensive review of portfolio theory alternatives, and the advantages and limitations of each alternative.

While asset allocation decisions have been thoroughly debated and explored in academic literature, research on liability management has been more sparse, and was generally limited to high level capital structure decisions such as equity versus ~~debt allocations.~~

Early capital structure literature has stated that the choice of liability structure is irrelevant in the absence of contracting costs and taxes.[1] The introduction of frictions, such as taxes and bankruptcy costs, provides one possible justification for a non-trivial capital structure choice that is based on the trade-off between the tax benefit of debt and the bankruptcy costs of debt. The first quantitative analysis of this trade-off theory was provided by Leland[2] and subsequently by Leland and Toft.[3]

This section provides an overview of the different theories of debt management as they apply to fixed vs. floating rate debt, and their respective advantages and limitations.

2.1. MODERN PORTFOLIO THEORY

Modern portfolio theory (MPT) describes how rational, risk averse entities optimize their portfolio of securities through diversification. It measures the risk/return profiles of portfolios comprised of different individual securities, and plots a set of efficient investment portfolios (the efficient frontier) that maximize return for a given level of risk.

This approach was first formulated by Markowitz in 1952, who proposed that simply picking assets that yield the highest net present value leads to an inefficient portfolio. Instead, a more efficient mix of assets can lower risk for any given level of return.[4] MPT has traditionally been used as a framework to examine portfolio returns and risks, and its application was limited in the context of analyzing liabilities.

[1] Modigliani, F., Miller, M., 1958, The Cost of Capital, Corporation Finance and the Theory of Investment, American Economic Review, 48 (3), 261–297.
[2] Leland, H., 1994. Corporate Debt Value, Bond Covenants, and Optimal Capital Structure, Journal of Finance, American Finance Association, 49 (4), 1213-1252.
[3] Leland, H., Toft, K., 1996, Optimal Capital Structure, Endogenous Bankruptcy, and the Term Structure of Credit Spreads, Journal of Finance, 51 (3), 987-1019.
[4] Markowitz, H., 1952, Portfolio Selection, The Journal of Finance, 7 (1), 77-91.

While this concept provides a useful framework to underline the benefits of holding a diversified portfolio of securities, it is an incomplete analytical tool for a precise formulation of risk management for several reasons.

2.1.1. Diversification Risk

There are two types of risks associated with securities: systematic and non-systematic risk. The former is driven by the market-wide risk that affects all securities to varying degrees, such as a global recession. As a result, this type of risk cannot be reduced through portfolio diversification.

Conversely, non-systematic risk is specific to each security, and therefore can be reduced with appropriate diversification by adding uncorrelated securities to the portfolio. Empirical studies have shown that the average portfolio standard deviation could be reduced to less than 20% by incrementally increasing the number of securities in a portfolio.[5]

The limitation of this approach is that it is based on simplistic diversification, where each security in the portfolio is weighted equally. Theoretically, it is possible to construct a more efficient set of portfolios through a more judicious diversification procedure that leads to an efficient portfolio, one that maximizes return for a given level of risk. Furthermore, this analysis seems to imply that the best results are attained with an infinite number of securities in the portfolio to minimize risk. However, diversification and constant portfolio adjustments can be a costly process. Therefore, marginal returns resulting from diversification decrease eventually, implying that there is an optimal level of diversification to be attained.[6]

2.1.2. The Efficient Frontier – Theory

In constructing an efficient portfolio, the first step is to derive the total return of the portfolio, which is simply the arithmetic mean of the returns of each of the securities comprising the portfolio. Mathematically, the portfolio return can be expressed as follows:

$$\mathrm{E}(R_p) = \sum_{i}^{n} w_i \mathrm{E}(R_i) \qquad (1)$$

Where $\mathrm{E}(R_p)$ and $\mathrm{E}(R_i)$ denote the expected return of the portfolio and the individual securities, respectively, and w_i the relative weighting of each security in the portfolio. As a result, an

[5] Statman, M., 1987, How Many Stocks Make a Diversified Portfolio, Journal of Financial and Quantitative Analysis, 22, 353-363.
[6] Lubatkin, M., Chatterjee, S., 1994, Extending Modern Portfolio Theory into the Domain of Corporate Diversification: Does It Apply?, Academy of Management Journal, 37 (1), 109-136.

investor can achieve any level of return that lies in the range of the portfolio simply by changing the relative weighting of the individual securities.

The second step is to determine the risk level of the overall portfolio. Under MPT, risk is defined as the standard deviation (σ) from the mean. At this point, the concept of correlation among the securities (denoted by ρ_{ij}, which represents the correlation factor between security i and j) is introduced. Mathematically, portfolio risk can be represented as follows:

$$\sigma_p^2 = \sum_i^n w_i^2 \sigma_i^2 + \sum_i^n \sum_{j,j \neq i}^n w_i w_j \sigma_i \sigma_j \rho_{ij} \qquad (2)$$

For any given set of two distinct securities, the correlation between the two is likely to be less than perfect and hence ρ_{ij} will be less than 1. As a result, it is conceivable that a mix of relative weighting options exist that would lead to risk levels that are below those of the lowest risk asset in the portfolio.

2.1.3. The Efficient Frontier – Application

In theory, the construction of an efficient frontier can be easily formulated with equations (1) and (2) above. However, the application of theory to real market data presents several challenges, such as transaction costs, changing risk/return profiles, limitations to active portfolio management, and, in the case of debt portfolios, refinancing risk.[7]

For illustration purposes, this section of the analysis will focus on a simple two liability portfolio with constant risk/reward relationships as a base case. Under the base case scenario, it is assumed that a debt portfolio consists of just two elements: a fixed rate debt component and a floating rate component. As a proxy for returns and volatility, 3 month Banker's Acceptance ("BA") and 15 year Province of Manitoba debt yields were analyzed.

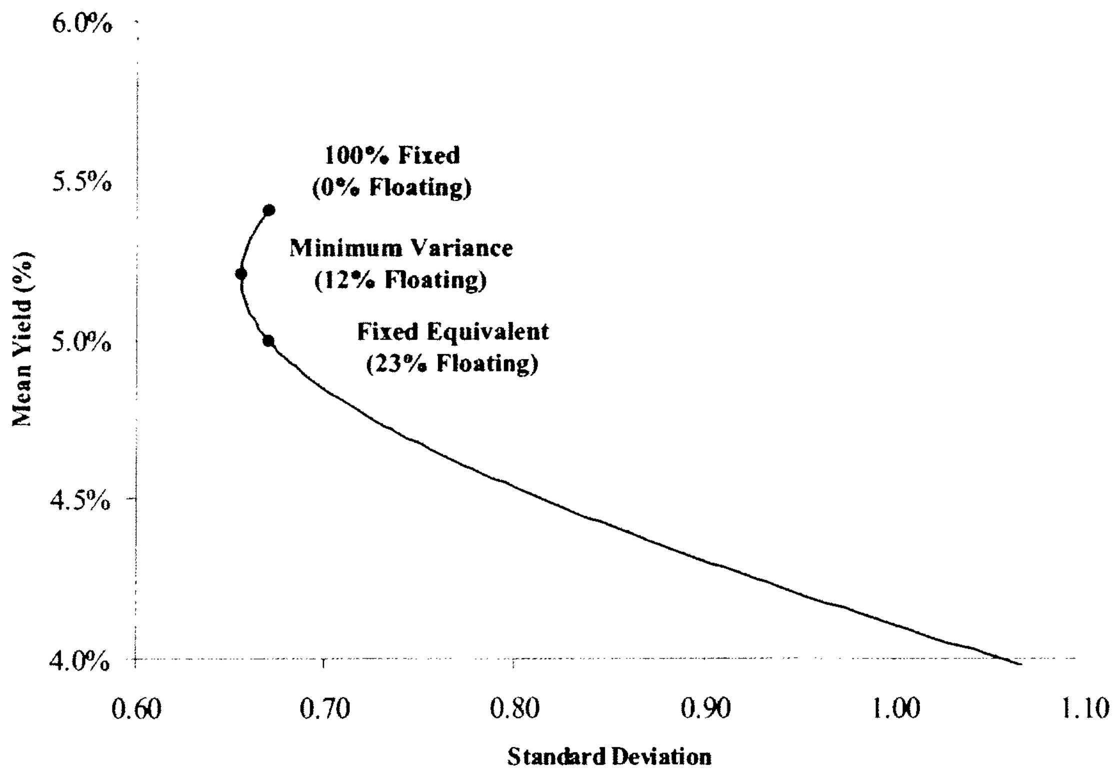
Table 3: Yield Correlation, 1999-2009[8]

	3 Month BA	15 Year Prov. of Man.
Mean Yield (%)	3.63%	5.40%
Standard Deviation (%)	1.27%	0.67%
Correlation	0.33	

[7] Fisher, L., 1975, Using Modern Portfolio Theory to Maintain an Efficiently Diversified Portfolio, Financial Analysts Journal, 31 (3), 73-85.
[8] Historical interest rate data as per Bloomberg.

An analysis using historical 10 year data yields the following efficiency frontier:

Figure 2: MPT Efficient Frontier, 1999-2009



According to this analysis, minimum volatility is achieved with a 12% floating rate debt component. With a 23% floating rate debt component, the same volatility can be achieved as 100% fixed, but at a lower cost of debt.

A company's appropriate mix of fixed and floating rate debt is ultimately a function of its risk appetite. However, this analysis demonstrates that regardless of a company's risk profile, a more efficient risk/cost equilibrium can be attained by introducing a floating rate element to the company's debt portfolio.

2.1.4. Advantages

MPT is a simple, straight-forward analysis that provides a broad context for understanding the interactions of systematic risk and reward. The theory concludes that an appropriate diversification of debt instruments may help lower the cost of debt.

2.1.5. Limitations

MPT relies on the assumption that the correlation between short and long-term interest rates stays constant over time. Historically there has been no evidence to support this assumption, given that yield curve slopes have shown high levels of volatility over the past ten years.

While on average, over the past decade, there has been a positive relationship between short and long-term rates, it is apparent that correlation factors change depending on the specific timeframe chosen.

Table 4: Yield Correlation, 1999-2003 vs. 2004-2009[9]

1999-2003	3 Month BA	15 Year Prov. of Man.
Mean Yield (%)	4.05%	5.99%
Standard Deviation (%)	1.27%	0.42%
Correlation	0.58	

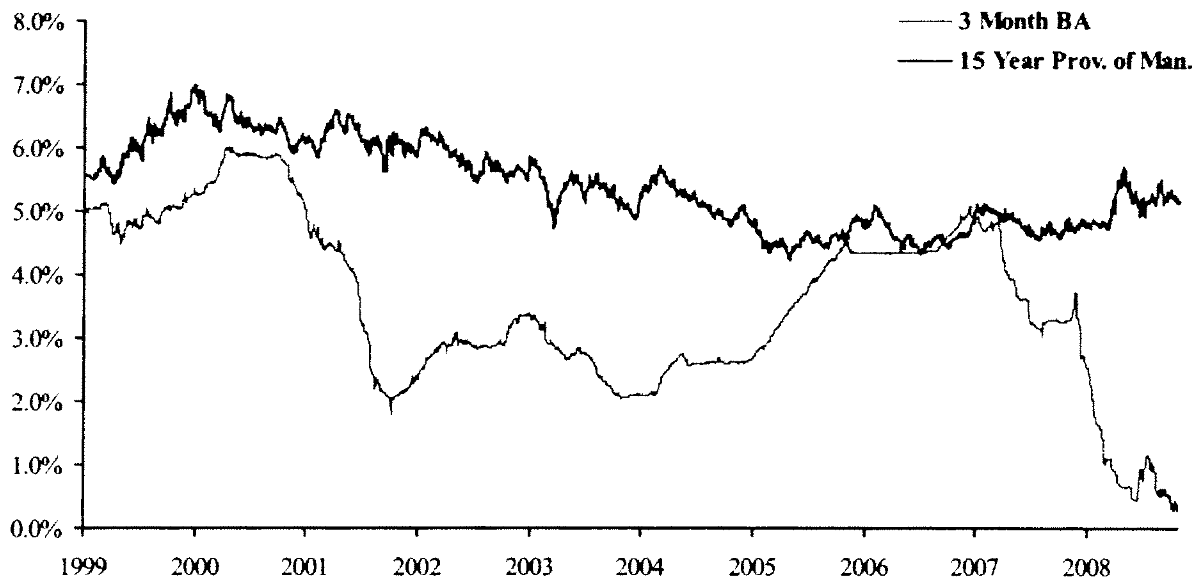
2004-2009	3 Month BA	15 Year Prov. of Man.
Mean (%)	3.23%	4.87%
Standard Deviation (%)	1.14%	0.31%
Correlation	-0.56	

Figure 3 illustrates this point graphically. It is apparent that during the first five years, both rates move together, leading to a strong positive correlation of 0.58. However, from 2004 onwards, interest rates move in opposite directions, leading to a negative correlation of -0.56.

[9] Historical interest rate data as per Bloomberg.

38

Figure 3: Historical Interest Rates[10]



As a result, MPT yields two separate efficiency frontiers for the two time periods. In the 1999-2003 timeframe, minimum variance is achieved at a 100% fixed portfolio, whereas for 2004-2009, a 16% floating mix yields the lowest volatility.

Furthermore, in the debt management context, MPT's only objective is to minimize a company's cost of debt and its volatility. However, this is an incomplete analysis because it ignores operational cash flow volatility, which may be correlated with movements in interest costs. Given that profit is the measure of financial performance, MPT results in an incomplete analysis.

Despite these limitations, MPT does present itself as a useful tool to evaluate the appropriate mix of fixed and floating rate debt. One generic conclusion that can be derived from this exercise is that depending on the correlation of fixed and floating rates, an appropriate diversification of different debt instruments may help lower the cost of debt for a given level of risk.

2.2. Alternative Theories

2.2.1. Post Modern Portfolio Theory

The Post Modern Portfolio Theory (PMPT) was developed to address some of the limitations of the MPT, namely the symmetrical distribution of returns. To address this, Rom and Ferguson introduced the concept of volatility skewness, which denotes the ratio of a distribution's

[10] Historical interest rate data as per Bloomberg.

percentage of total variance from returns above the mean, to the percentage of the distribution's total variance from returns below the mean.[11]

One way to address some of the major shortcomings of MPT, namely the symmetrical distribution of returns, is to introduce a three-parameter lognormal distribution of returns to account for the skew in the volatility of returns. The lognormal distribution assumes that the natural logarithm of the returns follow a normal distribution.

PMPT refines the MPT model to account for asymmetric expected returns, and reduces skewed volatility. However one of the limitations of PMPT is that it ignores the asset-side volatility factors of the business, and while it is considered a useful academic tool to analyze portfolio performance, it is an incomplete approach to corporate risk management decisions.

2.2.2. Market Timing Theory

The market timing approach dictates that companies should determine their fixed vs. floating rate debt policy according to the expectations of changes in future interest rates.

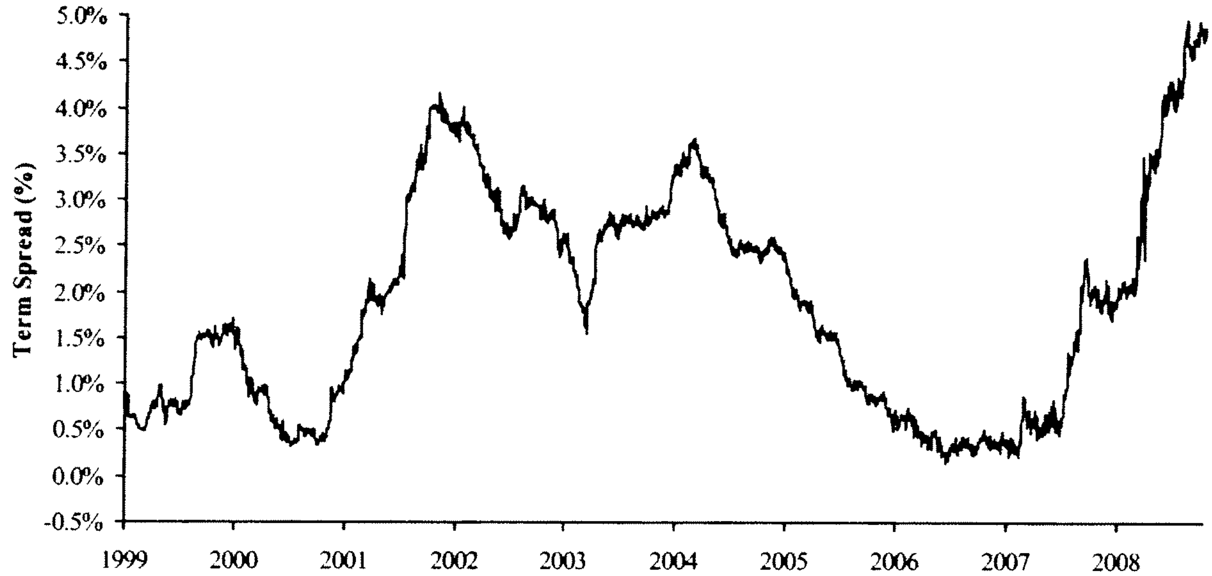
Steeper yield curves imply greater difference between short and long-term interest rates, and would entail a higher proportion of floating rate debt in the short term to lower interest expense. If companies believe they can effectively time the market, thereby reducing their cost of capital, then the interest rate exposure selection should be driven by movements in interest rates.[12]

The concern associated with this approach is that market timing is macroeconomic focused and may be considered speculative in nature. Market timing seeks to adjust the cost of debt based on current and expected yields, but does not aim to reduce other volatility factors correlated with interest rate movements. The cost of debt is only one component of financial performance.

Figure 4 depicts the term spread of the 3 month and 15 year Province of Manitoba bonds, illustrating the current steepness of the yield curve, implying that practicing a higher proportion of floating rate debt would result in a lower interest expense.

[11] Rom, B., Ferguson, K., Post-Modern Portfolio Theory Comes of Age, 1993, Journal of Investing, 1, 349-364.
[12] Faulkender, M., 2005, Hedging or Market Timing, Journal of Finance, 60 (2), 931-962.

Figure 4: Term Spread – 3 Month BA vs. 15 Year Province of Manitoba[13]



The market timing approach seeks to take advantage of a steep yield curve. This strategy is particularly relevant ~~in the~~ current economic environment where interest rates, especially short-term ones, ~~are at~~ historical lows. The market timing approach reflects economic factors that management should take into account when seeking to minimize interest expense, which has a direct impact on the profitability of the company. However, this approach has traditionally focused on yield curve slopes, without taking into account the overall level of interest rates, which should be reflected in debt structuring decisions.

Other pitfalls associated with market timing theory are that it ignores the asset volatility factors of the business and relies on a view on the future direction of interest rates, which could be interpreted as speculation. ~~Also, the~~ framework is unable to quantify the risks associated with issuing floating rate debt; analysis suggests that a debt portfolio with a high proportion of floating rate debt will result in higher interest expense volatility.

2.2.3. Asset/Liability Management

The asset/liability ~~approach~~ examines both revenues and expenses simultaneously and formulates an optimal mix of fixed and floating rate debt based on reducing the volatility factors affecting the company. Taking an asset/liability management approach considers interest expense management in the context of the overall business, not as a standalone item. The approach seeks

[13] Historical interest rate data from Bloomberg.

to optimize net income, which is the key metric of relevance for Manitoba Hydro. Carrying more floating rate debt can have a volatility-decreasing effect by offsetting changes in interest rates.[14] Hedging strategy impacts a company's ability to pay interest, and meet its debt costs on a regular basis.[15] High variability in cash flows negatively impacts capital expenditure plans because debt cannot be used as a supplement to internally generated cash flows to fund capital requirements.[16]

In Hackbarth et al., the authors examine the optimal mixture of bank and market debt to explore dynamic capital structures in the context of realistic macroeconomic settings with interest rate and inflation risks. However, all market debt is assumed to be in the form of fixed rate bonds.[17]

In most academic research papers, corporate debt is only represented by fixed coupon bonds and does not take into consideration interest rate movements and inflation risks. Hence, limited analytical results relevant to the scope of this assessment are available.

Other hedging theories stipulate that by matching the interest rate exposure of the liabilities to that of their assets, firms can reduce variability of their cash flows and, as a result, lower their expected cost of financial distress and capture greater tax shield benefits.[18] Hedging also allows firms to minimize how often they have to raise external capital.[19] These academic papers have not provided any quantitative estimate of the optimal breakdown between various types of debt instruments.

Martellini and Milhau tie together these two separated strands of the corporate finance literature by providing the first quantitative analysis of capital structure and debt management choices in a unified framework. This research shows that risk management motives can be quantitatively analyzed in the context of a formal capital structure model. To do that, it considers the optimal allocation to various competing forms of liabilities in a more realistic stochastic environment. In the presence of interest rate and inflation risks, they obtain analytical expressions for the price of, and optimal allocation to, various forms of liabilities classes (fixed rate bonds, floating rate bonds and inflation indexed bonds, in addition to equity).[20]

[14] Chava, S., Purnanandam, A., 2007, Determinants of the Floating-to-Fixed Rate Debt Structure of Firms, Journal of Finance, 50 (3), 789-819.
[15] Smith, C., Stulz, R., 1985, The Determinants of Firms' Hedging Policies, Journal of Financial and Quantitative Analysis, 20 (4), 391-405.
[16] Froot, K., Scharfstein, D., Stein, J., 1993, Risk Management: Coordinating Corporate Investment and Financing Policies, Journal of Finance, 48 (5), 1629-1658.
[17] Hackbarth, D., Hennessy, C., Leland, H., 2007, Can the Trade-off Theory Explain Debt Structure?, Review of Financial Studies, 20 (5), 1389-1428.
[18] Smith, C., Stulz, R., 1985, The Determinants of Firms' Hedging Policies, Journal of Financial and Quantitative Analysis, 20 (4), 391-405.
[19] Froot, K., Scharfstein, D., Stein, J., 1993, Risk Management: Coordinating Corporate Investment and Financing Policies, Journal of Finance, 48 (5), 1629-1658.
[20] Martellini, L., Milhau, V., 2008, Capital Structure Choices and the Optimal Design of Corporate Market Debt Programs, Second Singapore International Conference on Finance 2008.

This analysis shows that debt management decisions have an impact on capital structure decisions. The optimal allocation depends on the correlation between interest rates and the firm's asset value. The volatility of the interest rate and the speed of mean reversions also play an important role in the determination of the debt structure.

The limitation associated with taking an asset/liability management approach to formulating an optimal debt mix is that it is often difficult to segregate both the factors that impact operating cash flow and analyze their correlation with interest rates.

2.3. CONCLUSION

NBF's comprehensive review of academic literature on alternative debt portfolio frameworks and their respective advantages and limitations established that the asset/liability management approach is the most appropriate framework for assessing Manitoba Hydro's fixed vs. floating rate debt policy.

In NBF's opinion, the asset/liability model is the only alternative that allows for the optimization of net income as it seeks to match the assets and liabilities of a company.

3. IDENTIFICATION OF KEY FACTORS

Having identified the asset/liability management framework as the appropriate approach for this analysis, NBF examined the sources of volatility of the assets and liabilities affecting the historical financial performance of Manitoba Hydro.

The asset analysis identified the volatility factors affecting the drivers of Manitoba Hydro's revenue, and likewise, the liabilities analysis identified the volatility factors affecting Manitoba Hydro's costs. The key factors identified in this analysis were used as the drivers of the technical analysis and scenario testing.

3.1. ASSETS

Assets are defined as the stream of cash inflows that result from operational assets. These include both domestic and extraprovincial electricity sales revenue.

3.1.1. Domestic Utility Rates

The prices charged for the sale of electricity and natural gas within Manitoba are subject to review and approval by the Public Utilities Board of Manitoba ("Board"). The Board is the provincial government's regulatory body through which all of Manitoba Hydro's electricity and natural gas rate applications must be approved before rate increases or decreases can become effective.

Table 5: Domestic vs. Extraprovincial Electric Revenues and Volumes[21]

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Electric Revenue ($mm)	$1,122	$1,212	$1,362	$1,243	$1,218	$1,458	$1,753	$1,558	$1,633	$1,675
Domestic Revenue ($mm)	$748	$737	$781	$786	$875	$918	$939	$984	$1,024	$1,074
GWh	16,331	15,820	16,698	16,958	18,953	19,323	19,781	19,976	20,555	21,109
$/MWh	$34.26	$39.09	$47.24	$46.97	$49.22	$50.03	$53.00	$50.75	$49.33	$51.29
Export Revenue ($mm)	$374	$475	$581	$457	$343	$540	$814	$574	$609	$601
Import Costs ($mm)	$19	$30	$56	$126	$506	$101	$86	$186	$99	$136
Net Export Rev. ($mm)	$355	$445	$525	$331	($163)	$439	$728	$387	$510	$465
Export GWh	10,911	12,154	12,298	9,735	6,976	10,789	15,360	11,305	12,348	11,720
Export $/MWh	$34.26	$39.09	$47.24	$46.97	$49.22	$50.03	$53.00	$50.75	$49.33	$51.29
Import GWh	978	916	1,458	3,043	9,627	2,278	1,787	3,454	2,098	2,579
Import $/MWh	$18.97	$32.43	$38.36	$41.41	$52.58	$44.19	$48.28	$53.94	$47.09	$52.91

3.1.2. Extraprovincial Revenues

Extraprovincial revenues are subject to two main macroeconomic volatility factors: spot/forward rate risk in the Mid-West Independent Operating (MISO) system and foreign currency exchange exposure. MISO is an open-market, US electrical grid. Manitoba Hydro sells excess electricity to this grid through contracts or at the prevailing spot price. Constant fluctuations in spot prices affect forward contract prices and total extraprovincial revenue. Due to extraprovincial revenues generated from sales into the MISO grid, Manitoba Hydro is exposed to fluctuations in foreign currency exchange rates.

Manitoba Hydro engages in two types of export sales: contracted export sales and spot price export sales. Export contracts account for most of Manitoba Hydro's exported electricity being sold on-peak capacity. Current long-term export contracts produce export sales of about 2,500 GWh/year at prices above $50.00/MWh (average of $55.00/MWh for fiscal 2007/08). Other contracts are short-term market based agreements, and pricing is below $40.00/MWh for sales volumes of 1,500 GWh/year.

Opportunity export sales are spot price sales that attempt to capture the remainder of on-peak availability, and rely on shoulder and off-peak periods to maximize total electrical sales. These

[21] Data as per Manitoba Hydro.

off-peak sales in fiscal 2007/08 accounted for an additional 8,000 GWh in 2007/08, however brought the export average price below $50.00/MWh.

Historically, export revenues have accounted for a significant proportion of total revenues, accounting for an average of 37% over the past 10 years with a standard deviation of 4.9% over the same period.

Table 6: Domestic vs. Extraprovincial Revenues[22]

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Domestic Rev. ($mm)	$748	$737	$781	$786	$875	$918	$939	$984	$1,024	$1,074
Extraprov. Rev. ($mm)	$374	$475	$581	$457	$343	$540	$814	$574	$609	$601
Total Electric Revenue	**$1,122**	**$1,212**	**$1,362**	**$1,243**	**$1,218**	**$1,458**	**$1,753**	**$1,558**	**$1,633**	**$1,675**
Extraprovincial (%)	33%	39%	43%	37%	28%	37%	46%	37%	37%	36%
					Standard Deviation of Proportion of Extraprovincial Revenue:					*4.9%*

3.1.3. Potential Hydraulic Generation/Reserves

Reservoirs within the Nelson-Churchill drainage basins allow Manitoba Hydro to store water for future electrical generation. These reserves are held at virtually no economic cost and it allows Manitoba Hydro to reserve power generation for future seasons in order to meet variable domestic demand and to optimize export sales during peak load demand in the MISO grid.

3.2. Liabilities

Liabilities are defined as the stream of cash outflows that result from both operating and financial activities. These include cost of power purchased from extraprovincial sources, as well as interest payments on issued debt.

3.2.1. Purchased Power

Purchased power costs are subject to spot rate risk in the MISO system given that Manitoba Hydro purchases electricity from the MISO grid at the prevailing spot price. Constant movement in spot prices affects the cost of purchased power.

[22] Data as per Manitoba Hydro.

3.2.2. Operation and Maintenance Expenses

Costs and operating programs have increased due to: increased maintenance requirements (due to an aging infrastructure); wage and benefit settlements that exceed projected inflation; additional overtime and increased staffing levels (to meet extraprovincial requirements); the expansion of programs (to meet higher than expected domestic customer numbers and needs); and the meeting of environmental and other stakeholder expectations. These costs have been compounded by the recent shortage of skilled labour in Manitoba, which results in higher training and labour costs.

3.2.3. Water Rental Fees

Water rentals relate to the use of provincial water resources. Water rentals and assessment fees are determined by the amount of annual water-flow used during the year.

3.2.4. Debt and Interest Expenses

Manitoba Hydro maintains a proportion of floating rate debt in its debt portfolio, which is subject to the volatility of the underlying rate drivers (3 month BA in Canada, 3 month LIBOR in the US). Their respective correlations with other key factors are analyzed in detail in the technical analysis portion of this assessment, and form the basis for the scenario analysis.

The ~~portion~~ of total debt denominated in US Dollars is in place as part of Manitoba Hydro's Exposure Management Program ("EMP") to manage the currency risk associated with extraprovincial power sales. This portion of total debt establishes a natural hedge against US Dollar denominated extraprovincial revenues. This assumption is discussed further in section 5.1.1.

3.3. HYDROLOGY RISK

Based on a study published in Manitoba Hydro's 2008/09 General Rate Application, 94 years of river flow history revealed that Manitoba has faced drought conditions in 23 of the 94 years (approximately 1 year in every 4). Consecutive years of drought conditions occurred from 1929 to 1932, 1936 to 1942, 1976 to 1977, 1980 to 1981, and 1987 to 1991. The most recent drought was in 2003-04. In Table 7, Manitoba Hydro has forecasted the impact of a drought on retained earnings.

Table 7: Hydrology Risk Analysis[23]

Event in Forecast Period	Frequency	Cumulative Retained Earnings Reductions ($mm)
One Year Drought (50% of 2003/04 loss)	1 in 10	($490)
2003/04 Drought	1 in 15	($891)
Five-Year Drought (1987-91)	1 in 50	($2,800)
Seven-Year Drought (1936-42)	1 in 100	($3,500)

Hydrology is considered a key volatility factor affecting the financial performance of Manitoba Hydro. Although hydrology risk can affect the volatility of regulated electricity rates and extraprovincial generation, there is no causal effect between hydrology and macroeconomic factors and therefore cannot, in the context of this assessment, be deemed a key variable in determining the optimal fixed versus floating rate debt policy.

3.4. Conclusion

The foregoing analysis demonstrates that Manitoba Hydro's business model is subject to several volatility factors that affect its assets and ~~liabilities.~~ In formulating an optimal fixed vs. floating rate debt policy, the relationship between these factors justifies the use of an asset/liability management framework. Such an approach will allow Manitoba Hydro to lower net income volatility risk while attaining an optimal level of return.

[23] Data as per Manitoba Hydro.

4. PEER GROUP ANALYSIS

As part of this assessment, NBF examined Manitoba Hydro's peer group's fixed vs. floating rate debt policies. The peer group consisted of vertically integrated electric utilities, and was segmented into two separate types of peers: crown utility corporations and publicly-traded corporations.

Table 8: Peer Group List

Crown Utility Corporations	Publicly Traded Corporations
BC Hydro	Emera Inc.
SaskPower	Fortis Inc.
Hydro Québec	Canadian Utilities Limited
New Brunswick Power	
Newfoundland & Labrador Hydro (Nalcor Energy)	

First, NBF tracked each of the peer's historical floating rate debt mix over a 10 year period and found evidence that Manitoba Hydro's peers utilized market timing to adjust their fixed vs. floating rate debt mix to account for prevailing interest conditions.

Second, NBF extended the key factor identification process to the peer group to identify the sources of volatility affecting their assets and liabilities, and found evidence of asset/liability management.

The purpose of the peer group analysis was not to provide an evaluation of the peer group's fixed vs. floating rate debt policy. Rather, this analysis simply compared Manitoba Hydro's policy to its peers and found that it was consistent with industry practice from an asset/liability management perspective.

4.1. MARKET TIMING EVIDENCE

Market timing provides context as to the macroeconomic reasoning for changes in floating rate debt proportions over time. Companies use this strategy to take advantage of a steep yield curve by increasing floating rate debt, or by fixing their floating rate debt during low interest rate timeframes.

The market timing component of this analysis first examined the relationship between the floating rate debt mix and the slope of the yield curve. Figure 5 depicts the relationship between the peer group's floating rate debt proportion and term spreads in the past 10 years:

Figure 5: Term Spread vs. Average Peer Group Floating Rate Debt %[24]

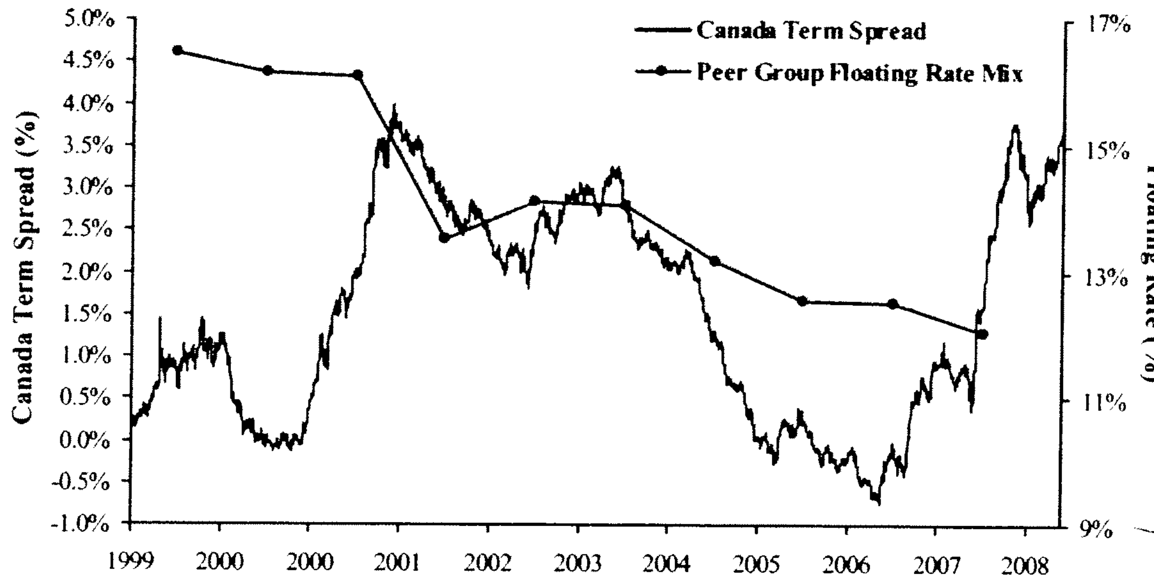


Figure 5 proves that while the peer group's floating rate debt proportion has followed the term spread between 2000 and 2006, these companies have not increased their proportion of floating rate debt in the context of the recent spike in term spreads that has taken place over the last two years.

One reason for this divergence could involve a lag effect between the term spread change and its reflection in company policy. However, another explanation could be the fact that the current low-interest economic environment provides an opportunity for companies to fix their long-term debt at cheaper prices than historical levels.

Figure 6 tests this latter hypothesis by examining the relationship between the peer group's average floating rate debt proportion and long-term interest rates:

[24] Historical interest rate data as per Bloomberg, peer group floating rate mix as per peer group company reports.

Figure 6: 20 Year Government of Canada vs. Average Peer Group Floating Rate Debt %[25]

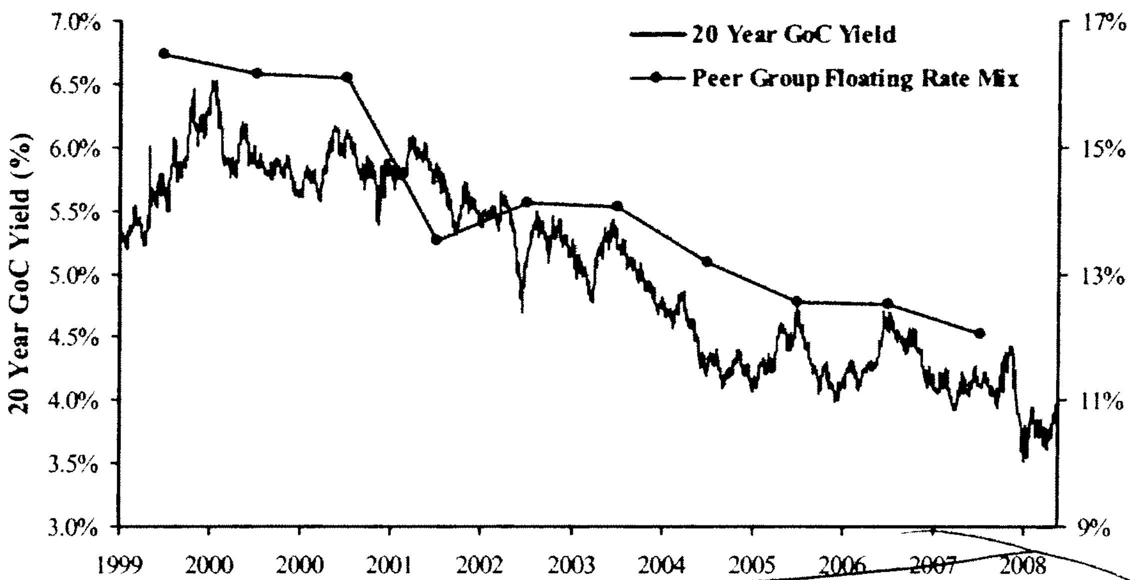


Figure 6 provides evidence that given the unique interest rate environment today, these companies are choosing to engage in market timing not by taking advantage of the increasing term spread, but rather by taking the opportunity to lower their interest rate volatility by fixing more of their debt at historically lower levels.

4.2. Asset/Liability Management Evidence

The asset/liability management approach is a more fulsome and detailed methodology of determining the reasons behind implementing certain individual debt management policies. The sources of revenue and costs were both examined, and the analysis assessed volatility factors associated with changes to each company's net income.

4.2.1. Assets

4.2.1.1. Domestic Utility Rates

The prices charged for the sale of electricity and natural gas within the respective operating provinces of the peer group is subject to review and approval by each public utilities board/commission, with the exception of companies that operate in merchant markets such as Alberta. The public utilities board/commission is the respective provincial government's regulatory body through which all electricity and natural gas rate applications must be approved before rate increases or decreases can become effective.

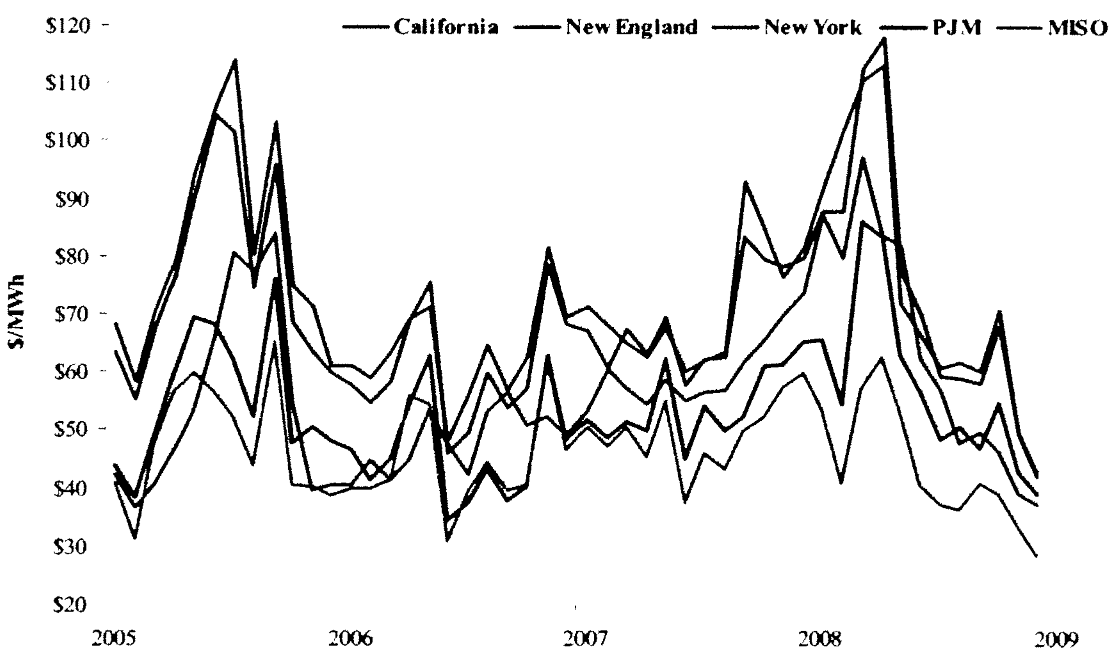
[25] Historical interest rate data as per Bloomberg, peer group floating rate mix as per peer group company reports.

Regulated electricity rates are determined by a host of factors including, but not limited to, inflation risk, electricity demand risk and fuel price risk.

4.2.1.2. Export Revenue

Export revenues are subject to two main macroeconomic volatility factors; spot/forward prices associated with selling excess electricity to open-market grids and foreign currency exchange exposure. Open-market grids that the peer group sells excess electricity into include; California ISO (CISO), ISO New England, MISO, New York Independent System Operator (NYISO), PJM Interconnection and Alberta ISO. The peer group sells excess electricity to these open-market grids at the prevailing respective spot/forward prices. Constant changes in spot prices affect total export revenue. Secondly, due to export revenues generated from sales into the previously mentioned open-market grids, export revenues are exposed to fluctuations in foreign currency exchange rates.

Figure 7: Historical ISO Electricity Spot Prices[26]



4.2.1.3. Generation Risk

Natural weather conditions such as hydrology and wind levels impact generation and its volatility increases dependency on import power. The unpredictability of these sources of generation affect the volatility of regulated electricity rates, however it is not a risk that is correlated with macroeconomic metrics such as interest rates and cannot be used in forecasting

[26] Historical ISO electricity spot prices as per Bloomberg.

future impacts on financial performance, specifically through determining an optimal debt policy.

4.2.2. Liabilities

4.2.2.1. Operation and Maintenance Expenses

Unexpected inflation risk is the key metric affecting volatility in operation and maintenance expenses of the peer group. Items such as unforeseen changes in staffing levels/costs are responsible for this volatility.

4.2.2.2. Purchased Power

Purchased power costs are subject to two main volatility factors: spot rate risk associated with purchasing electricity due to domestic generation shortfall on open-market grids and foreign currency exchange exposure. The open-market grids that the peer group purchases electricity from include: ISO New England, MISO, New York Independent System Operator (NYISO), and PJM Interconnection. Secondly, due to purchased power from electricity in the previously mentioned open-market grids, purchased power is exposed to fluctuations in foreign currency exchange rates.

The cost of producing power from certain additional sources of generation is an additional volatility factor affecting the peer group. Input fuel prices for power generation from natural gas, coal and oil are all examples of fuel costs that are subject to external pricing.

4.2.2.3. Debt and Interest Costs

Peers that maintain a floating portion of their total debt are subject to volatilities in rate drivers (BA and LIBOR). NBF's peer group analysis demonstrated that among the peers, only SaskPower fixed all of its debt and hence was not affected by fluctuations in short-term interest rates.

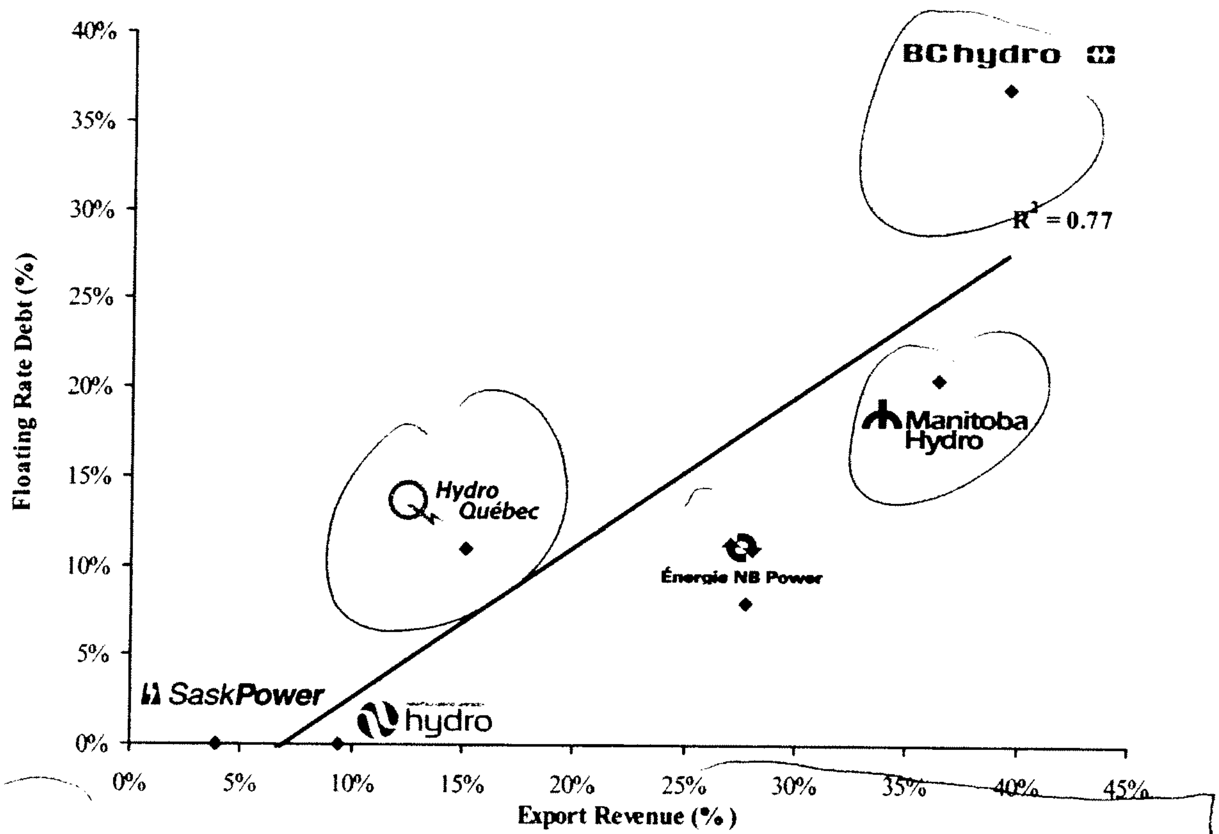
Furthermore, the analysis also demonstrates that peer group members issue a portion of their debt in foreign currencies to mitigate ~~foreign revenue~~ exposures.

4.2.3. Asset/Liability Management Evidence

The foregoing key factor identification process demonstrated that Manitoba Hydro's peers are subject to volatility factors that warrant an asset/liability management approach to their fixed vs. floating rate debt policy.

In Figure 8, an evaluation of the crown utility peer group's operations indicates that there is a positive relationship (as evidenced by an R^2 of 0.77) between the exposure to exported power revenue, which is subject to spot/forward electricity price volatility, and the proportion of floating rate debt on the company's balance sheet. Figure 8 suggests that as revenues become more dependent on exports, the floating rate debt component becomes more prevalent.

Figure 8: Peer Group Floating Rate Debt % (2008) vs. Export Revenue % (Crown Utilities)[27]



Manitoba Hydro, BC Hydro, NB Power and Hydro Québec all export material amounts of power to various markets in the United States. To hedge part of the volatility of spot/forward prices, each respective peer carries a floating rate debt component in their debt portfolio.

4.3. Conclusion

The peer group analysis provided evidence of market ~~timing among Manitoba Hydro's~~ peer group. The historical analysis suggests that the peers adjusted their floating rate debt proportion to take advantage of the prevailing interest rate environment.

[27] Data as per Manitoba Hydro and peer group company reports.

The asset/liability portion of the analysis yielded evidence that Manitoba Hydro's fixed vs. floating rate debt policy is consistent with that of its crown utility peers from an asset/liability management perspective.

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

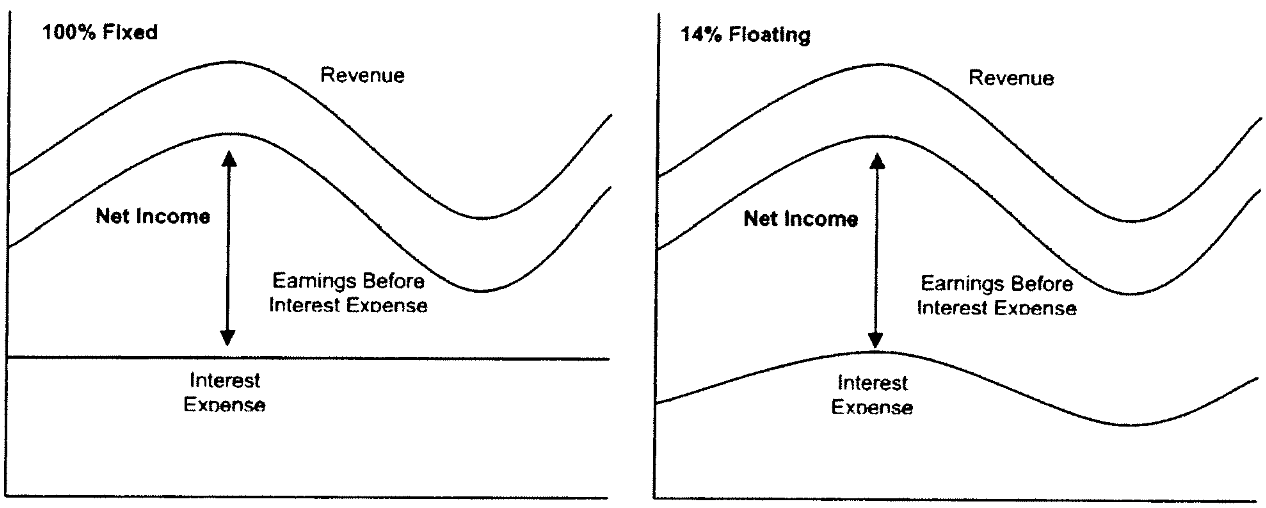
Correlations	Domestic Utility Rates	Export Power (ST and Spot)	Export Power (LT Contracts)	Canadian ST Interest Rates	US ST Interest Rates
Domestic Utility Rates	-	0.17	0.66	0.06	0.00
Extraprovincial Power (ST and Spot)	0.17	-	0.23	0.46	0.37
Extraprovincial Power (LT Contracts)	0.66	0.23	-	0.22	0.00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